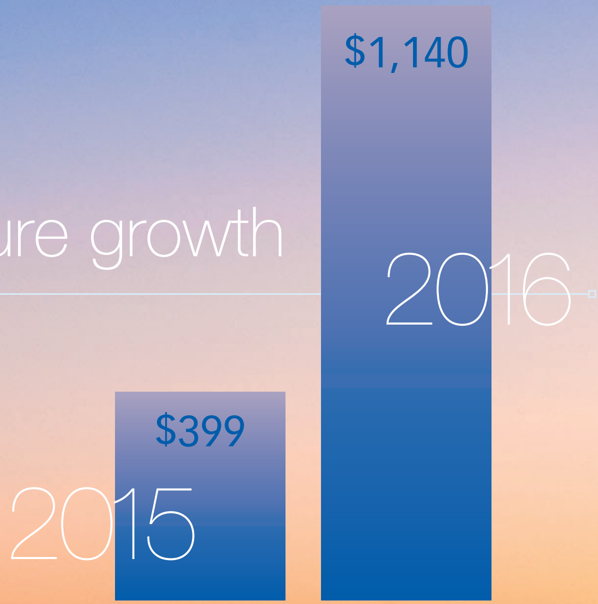
a clear vision

MPLX ENERGY LOGISTICS

2016 ANNUAL REPORT

for future growth

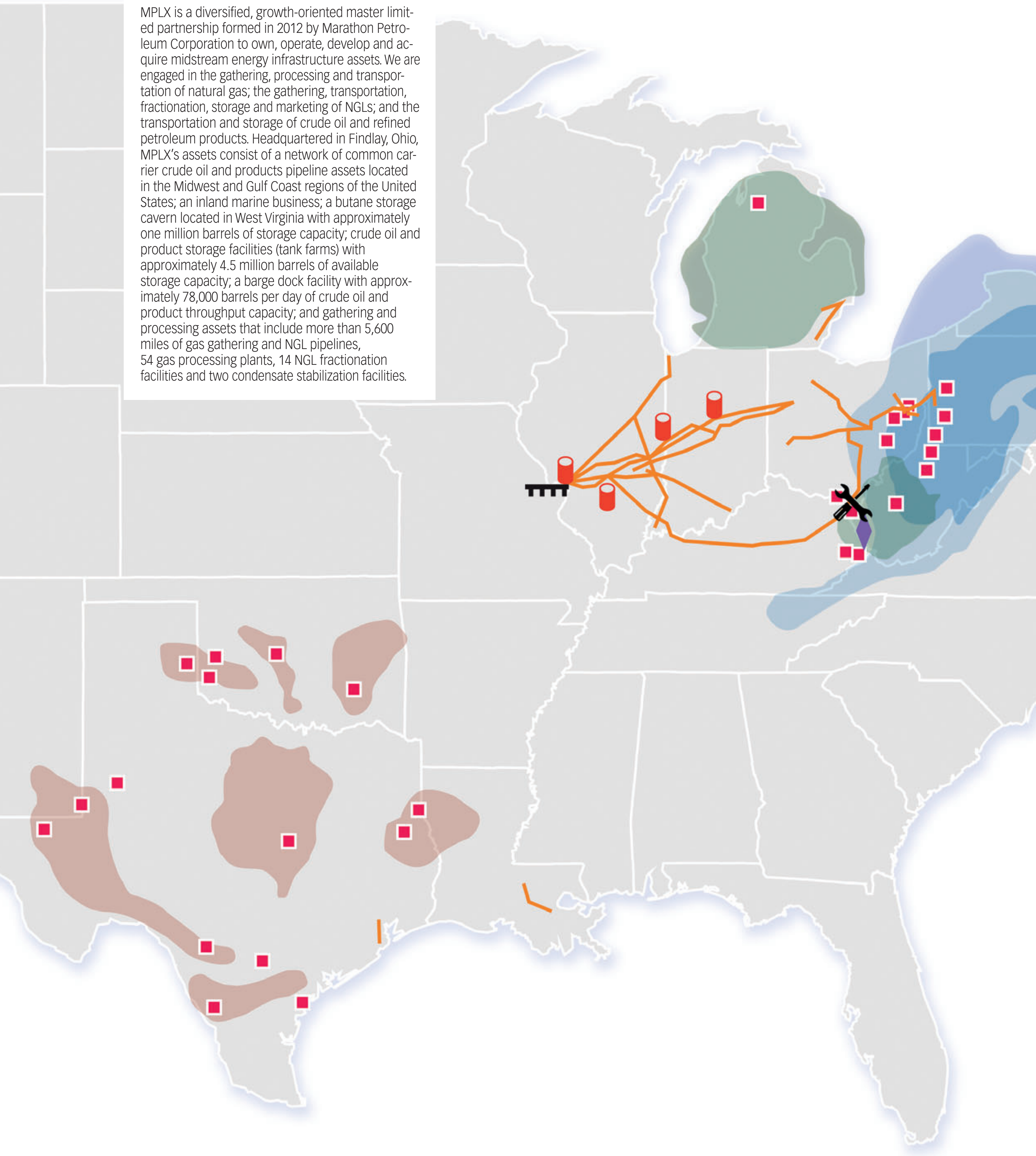


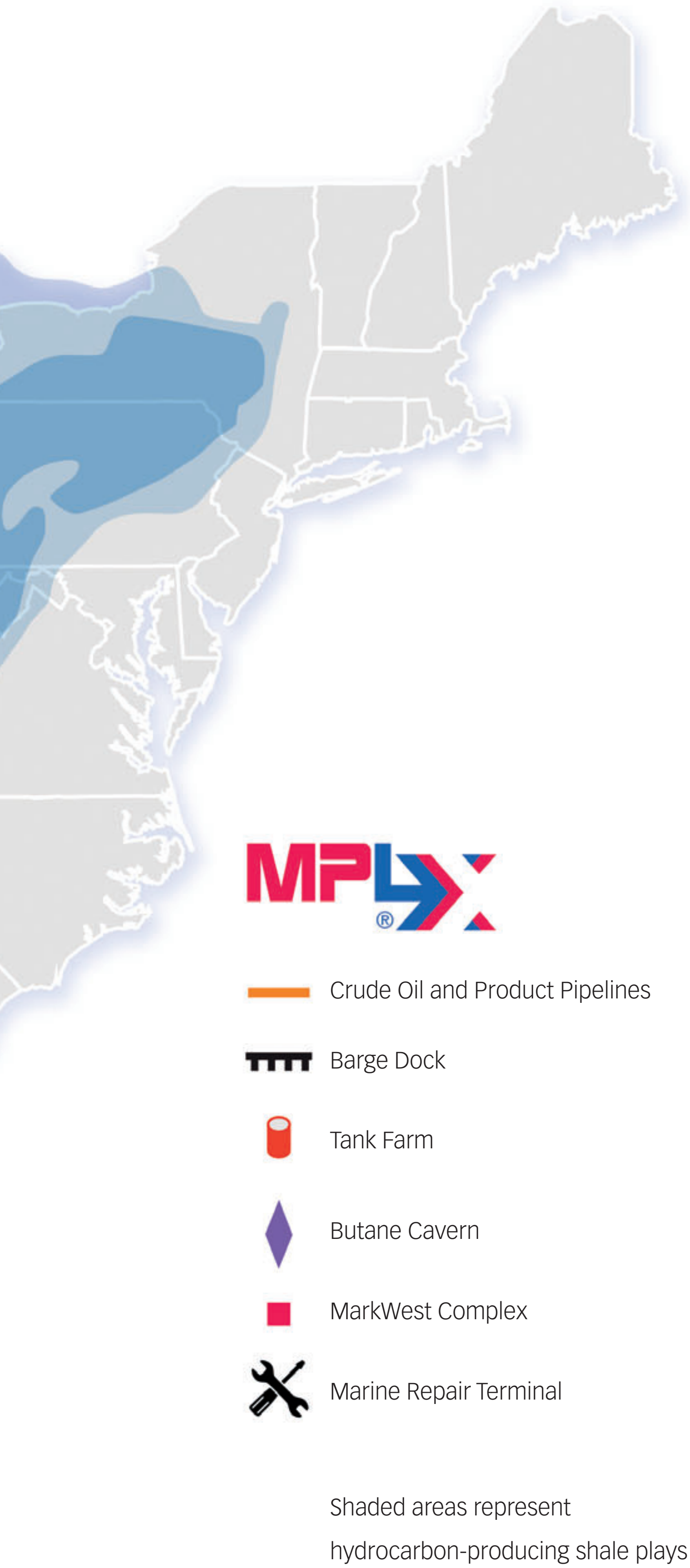
Distributable cash flow in millions attributable to MPLX.
Non-GAAP measure including MarkWest from Oct. 1, 2016. See reconciliation on Page 13.

MarkWest's gas processing and fractionation complex in Cadiz, Ohio

OPERATIONAL OVERVIEW

MPLX is a diversified, growth-oriented master limited partnership formed in 2012 by Marathon Petroleum Corporation to own, operate, develop and acquire midstream energy infrastructure assets. We are engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs; and the transportation and storage of crude oil and refined petroleum products. Headquartered in Findlay, Ohio, MPLX's assets consist of a network of common carrier crude oil and products pipeline assets located in the Midwest and Gulf Coast regions of the United States; an inland marine business; a butane storage cavern located in West Virginia with approximately one million barrels of storage capacity; crude oil and product storage facilities (tank farms) with approximately 4.5 million barrels of available storage capacity; a barge dock facility with approximately 78,000 barrels per day of crude oil and product throughput capacity; and gathering and processing assets that include more than 5,600 miles of gas gathering and NGL pipelines, 54 gas processing plants, 14 NGL fractionation facilities and two condensate stabilization facilities.





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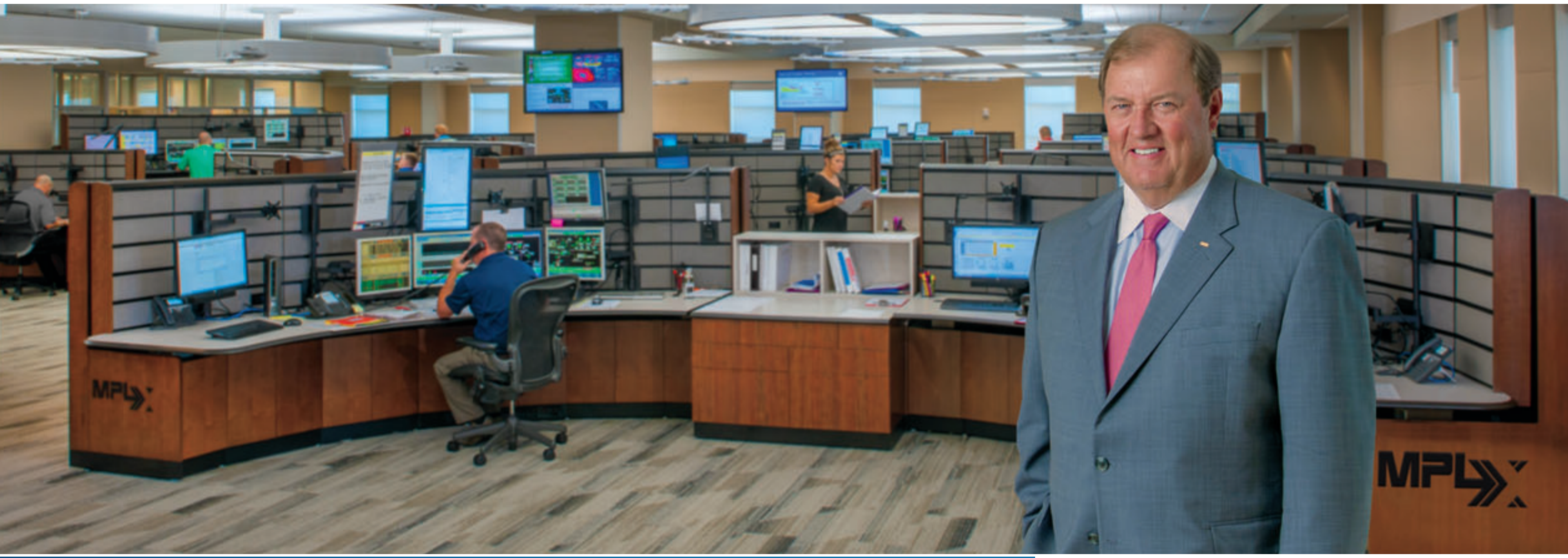
Glossary of Terms

bbl: barrels
bcf/d: billion cubic feet per day
bpd: barrels per day
cf/d: cubic feet per day
EBITDA: earnings before interest, taxes, depreciation and amortization
GP: general partner
IPO: initial public offering of units
LP: limited partner
MarkWest: MarkWest Energy Partners, L.P., is a wholly owned subsidiary of MPLX LP acquired in December 2015.
mbpd: thousand barrels per day
MLP: master limited partnership
mmcf/d: million cubic feet per day
MPC: Marathon Petroleum Corporation
MPL: Marathon Pipe Line LLC
NGL: Natural gas liquids

FROM THE CHAIRMAN AND CEO

Fellow unitholders,

Over the course of 2016, we executed on our plan to deliver strong operational and financial results. We achieved our targeted distribution growth rate and reduced our financial leverage while maintaining strong distribution coverage. We accomplished this by optimizing capital investments through organic growth projects and acquisitions from our sponsor Marathon Petroleum Corporation (MPC), managing costs, and continuing our sharp focus on customer service. We are excited about our future growth profile and the bold course of strategic actions over the next 12 to 18 months that we expect will approximately double the size of the partnership and lower our cost of capital.



2016 Success by the Numbers

In millions, except per unit and ratio data	2016	2015 (a)
Net income attributable to MPLX (b)	$ 233	$ 156
Adjusted EBITDA attributable to MPLX (c)	1,419	498
Net cash provided by operating activities	1,288	340
Distributable cash flow (DCF) (c)	1,140	399
Distribution per common unit (d)	2.05	1.82
Distribution coverage ratio (e)	1.23x	1.27x
Growth capital expenditures (f)	1,201	271

(a) MarkWest operations excluded from results and measures provided prior to the Dec. 4, 2015, merger.
(b) The year ended Dec. 31, 2016, includes pretax, non-cash impairments of $89 million related to an equity method investment and $130 million related to the goodwill established in connection with the MarkWest acquisition.
(c) Non-GAAP measure calculated before the distribution to preferred units and excluding impairment charges. See description in Non-GAAP financial measures on back cover.
(d) Distributions declared by the board of directors of our general partner.
(e) Non-GAAP measure. See description in Non-GAAP financial measures on back cover.
(f) Includes capital expenditures for inland marine business ("Predecessor"), acquired on March 31, 2016. Excludes capital expenditures for MarkWest acquisition. See description on Page 14.

MPLX significantly transformed its financial profile in 2016, our first full year with MarkWest Energy Partners. Our adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) nearly tripled over the prior year, to more than $1.4 billion, from $498 million in 2015. Net income rose 49 percent over the full-year 2015 to $233 million for 2016. Additionally, full-year distributable cash flow exceeded $1.1 billion. We also acquired MPC's marine business and invested $1.2 billion in an attractive

FROM THE CHAIRMAN AND CEO

set of organic projects that will continue to grow distributable cash flow and position MPLX as an industry leader.

Since our IPO in 2012, we have achieved 16 consecutive quarters of growing distributions for our unitholders. In 2016, we delivered a distribution growth rate of 13 percent, leading the industry among large-cap, diversified master limited partnerships (MLPs).

We remain committed to maintaining a strong balance sheet and an investment-grade credit profile.

The partnership ended the year in solid financial position with $2.7 billion of liquidity and a debt–to-pro forma adjusted EBITDA leverage ratio of 3.4 times. We also reported a robust full-year distribution coverage ratio of 1.23 times.

On Jan. 3, 2017, we set forth a new course of strategic actions intended to lower our cost of capital and provide increased visibility to our distribution growth. The partnership expects to acquire from MPC assets with approximately $1.4 billion in EBITDA in 2017. We expect to finance these proposed acquisitions through approximately equal portions of debt and equity, with the equity financing to be

Page 2: MarkWest's Hidalgo complex in Orla, Texas

Above: An employee at MarkWest's Sherwood facility in West Virginia, and the Keystone complex in Evans City, Pennsylvania

funded through common units issued to our sponsor, MPC, limiting our reliance on the public-equity market for financing.

As part of the strategic actions, an acquisition representing approximately $250 million of annual EBITDA closed in the first quarter of 2017.

Upon completion of the acquisitions, our size and scale would be among the largest in the industry with nearly equal contributions from our Logistics and Storage and Gathering and Processing segments and a pro forma expected EBITDA profile double what it is today.

Additionally, in conjunction with the acquisitions from our sponsor, we expect to exchange new MPLX common units for MPC's economic interest in the general partner, including incentive distribution rights.

competitively positioned

FROM THE CHAIRMAN AND CEO

These actions are expected to lower our cost of capital and position us for attractive growth in the long term. All of these transactions are subject to requisite approvals, market and other conditions, including tax and regulatory clearances.

With an investment-grade credit profile, an attractive portfolio of organic growth projects and potential for an improved cost of capital, we expect to deliver an attractive distribution growth rate, maintain a strong distribution coverage ratio and remain competitively positioned to generate long-term value for our unitholders.

Above left: MarkWest's Majorsville complex near Dallas, West Virginia

Above right: MarkWest's Keystone complex in Evans City, Pennsylvania

Page 5: The 50-mile Cornerstone Pipeline was completed in the fall of 2016

Sincerely,

Gary R. Heminger
Chairman and Chief Executive Officer

long-term value

LOGISTICS AND STORAGE

In 2016, MPLX's Logistics and Storage segment, which generates stable cash flows with its fee-based revenues and minimal direct commodity exposure, successfully commenced operations of the Cornerstone Pipeline, to transport liquids production from the Marcellus and Utica shales of Eastern Ohio to a tank farm in East Sparta, Ohio, and on to MPC's refinery in Canton, Ohio, providing improved industry connectivity to the region.

Cornerstone is the first step of MPLX's long-term pipeline investment program, an industry solution to transport condensate, natural gasoline, butane and diluent out of the Northeast.

LOGISTICS AND STORAGE

As part of that long-term plan, we also completed the construction of the Hopedale connection to the Cornerstone Pipeline to transport natural gasoline from the Marcellus and Utica shales to Midwest refiners, including MPC. MPLX is now in the process of expanding the capacity of existing pipelines, as well as constructing additional new pipelines as part of a larger build-out of the Utica Shale infrastructure, which is targeted for completion in mid-2017. With this mix of new and existing pipelines, MPLX is seizing a unique opportunity to support producer customer growth by connecting natural gas liquids (NGLs) to downstream markets in the Midwest and Canada through its extensive and growing distribution network.

A marine tow along the Ohio River near Cincinnati, Ohio

MarkWest's Ohio Condensate facility in Cadiz, Ohio

Additionally, in 2016, MPLX acquired MPC's inland marine business for $600 million, by issuing new units to MPC. As of Dec. 31, 2016, the inland marine business comprised 18 towboats, 204 barges and 18 leased barges. The business transports light products, heavy oils, crude oil, renewable fuels, chemicals and feedstocks in the Midwest and U.S. Gulf Coast regions, and accounts for nearly 60 percent of the total volume MPC ships by inland marine vessels. The addition of these assets, under a fee-for-capacity contract with MPC, adds approximately $120 million of annual EBITDA to the partnership.

MPLX also is expanding its network of butane caverns and tank farms to support MPC.

extensive distribution network

GATHERING AND PROCESSING

MPLX's Gathering and Processing segment delivered strong volume growth in 2016 and continues to provide exceptional organic growth opportunities to the partnership.

The addition of the MarkWest Gathering and Processing segment transformed the profile of our partnership to one of the largest natural gas processors in the United States and the largest processor and fractionator in the prolific Marcellus and Utica shales. Over the course of 2016, the partnership reported year-over-year increases of 11 percent in gathering, 13 percent in natural gas processing and 25 percent in natural gas liquids fractionation volumes.

MarkWest's Houston complex in Washington County, Pennsylvania

The partnership continues to pursue and execute exceptional growth opportunities, supporting a diverse set of over 160 producer customers in some of the nation's most prolific shale plays.

Included among its plans for continued growth, the partnership has secured new agreements with two of its largest producer customers in the Northeast region, to support the continued long-term development of substantial rich-gas acreage in the Marcellus and Utica shales.

Among the new plans are extended and amended agreements with Range Resources Corporation for which MPLX expects to construct an additional processing facility at its Houston complex in Pennsylvania in early 2018, and to commission the Harmon Creek complex, in Pennsylvania, by mid- to late 2018.

GATHERING AND PROCESSING

Additionally, the partnership announced that its wholly owned subsidiary, MarkWest Energy Partners, L.P., and Antero Midstream Partners LP have formed a strategic joint venture to support the development of Antero Resources Corporation's extensive Marcellus Shale acreage in the prolific rich-gas corridor of West Virginia. The joint venture is expected to commence new dedicated facilities beginning in 2017 and continuing into the future.

Ongoing joint venture development includes three new gas processing facilities, totaling 600 million cubic feet per day of incremental capacity, as well as future development by the joint venture of up to

Gas processing facilities of MarkWest's Sherwood complex in West Virginia

another eight processing facilities, which would be located at both the Sherwood complex and at a new location in West Virginia. Additionally, the joint venture has invested in 20,000 barrels per day of existing fractionation capacity at the Hopedale complex in Ohio, and has an option to invest in additional fractionation infrastructure to support future liquids production from its processing facilities.

MPLX is also growing its diversified footprint across established resource plays in Texas and Oklahoma. Specifically in the Delaware Basin of West Texas, the partnership completed the Hidalgo I plant in May 2016 and experienced strong volume increases from ongoing producer activity in the area, quickly ramping up to near-full utilization of the facility. In addition to West Texas, the partnership is actively growing its position in the STACK (Sooner Trend of the Anadarko Basin Canadian and Kingfisher counties) resource of Oklahoma's Cana-Woodford Shale.

GROWTH

MPLX looks forward to significant growth in 2017 and beyond as we enter a period of expansion driven by a recovery of commodity prices, increasing rig counts and growing customer exploration and development activity.

Through cost management, optimized capital investments and a continued relentless focus on customer service, we anticipate continued increases in gathered, processed and fractionated volumes in 2017.

The forecast for organic growth capital expenditures in 2017 is $1.4 billion to $1.7 billion and maintenance capital is forecast at approximately $100 million. Approximately $1 billion to $1.3 billion of these growth investments are expected to support producer customers in the Gathering and Processing

Welding Cornerstone Pipeline near Cadiz, Ohio

segment. During 2017, the partnership expects to complete 400 million cubic feet per day of additional natural gas processing capacity and 120,000 barrels per day of additional fractionation capacity, primarily in the Marcellus Shale.

The remaining $400 million is planned for the Logistics and Storage segment for the development of various crude oil and refined petroleum products infrastructure projects, including a build-out of Utica Shale infrastructure in connection with the recently completed Cornerstone Pipeline, a butane cavern in Robinson, Illinois, and a tank farm expansion in Texas City, Texas.

The partnership expects a distribution growth rate of 12 to 15 percent for 2017 and a double-digit rate for 2018. Looking forward, we also are energized by the transformative opportunity inherent in the strategic actions we announced on Jan. 3, 2017. The acquisition of assets generating approximately $1.4 billion in EBITDA, and the exchange of new MPLX common units for MPC's economic interests in the general partner will contribute to a reduced cost of capital and enhance the partnership's ability to deliver an attractive distribution growth rate for the long term.

With a simplified structure, full alignment with our sponsor MPC, and enhanced visibility to an attractive distribution growth rate, MPLX remains confident about its compelling long-term value proposition for investors.

BOARD OF DIRECTORS

Standing

Garry L. Peiffer
Retired President, MPLX GP LLC, and Executive Vice President, Corporate Planning and Investor and Government Relations, MPC. Mr. Peiffer joined MPC's predecessor, Marathon Oil Company, in 1974 and held various leadership positions with the company. He was named executive vice president of MPC in 2011, and president of MPLX in 2012.

Christopher A. Helms
President and CEO, U.S. Shale Management Company. Mr. Helms previously served in various leadership positions at NiSource Inc. and NiSource Gas Transmission and Storage. Mr. Helms was responsible for leading the company's interstate gas transmission and storage business.

John P. Surma
Retired Chairman and CEO, United States Steel Corporation. Prior to USS, Mr. Surma held various leadership positions at Marathon Oil Company, including senior vice president of Finance and Accounting, president of Speedway SuperAmerica LLC, and president of Marathon Ashland Petroleum LLC.

Michael L. Beatty
Former Chairman, Beatty & Wozniak, P.C. Mr. Beatty was a director of MarkWest Hydrocarbon and was named a director of MarkWest Energy Partners, L.P. in 2008. Prior to these positions, he was executive vice president, general counsel and director of the Coastal Corp., and chief of staff to Colorado Gov. Roy Romer.

Pamela K.M. Beall
Executive Vice President and Chief Financial Officer, MPLX GP LLC. Ms. Beall began her career with Marathon Oil Company and transferred to USX Corporation. After rejoining Marathon in 2002, she held various leadership positions, most recently executive vice president, Corporate Planning and Strategy, MPLX GP LLC.

Frank M. Semple
Retired Chairman, President and CEO, MarkWest Energy Partners, L.P. Mr. Semple joined MarkWest Energy Partners, L.P. in 2003 as president and CEO, and was elected chairman in 2008. He completed a 22-year career with The Williams Companies and WilTel Communications prior to MarkWest.

Timothy T. Griffith
Senior Vice President and Chief Financial Officer, MPC. Prior to MPC, Mr. Griffith was vice president and treasurer of Smurfit-Stone Container Corp., vice president and treasurer of Cooper-Standard Automotive and assistant treasurer of Lear Corp. He also held positions at Comerica Inc. and Citicorp Securities.

Seated

David A. Daberko
Lead Director, MPC. Mr. Daberko joined National City Bank in 1968 and went on to hold a number of management positions. He was named chairman of the board and chief executive officer of National City Corporation in 1995 and served in those capacities until his retirement in 2007.

Donald C. Templin
President, MPLX GP LLC and Executive Vice President, MPC. Mr. Templin was appointed senior vice president and chief financial officer of MPC in 2011, and vice president and chief financial officer of MPLX GP LLC in 2012. Prior to joining MPC in 2011, Mr. Templin was managing partner of PricewaterhouseCoopers LLP's audit practice in Georgia, Alabama and Tennessee.

Gary R. Heminger
Chairman and CEO, MPLX GP LLC, and Chairman, President and CEO, MPC. Mr. Heminger joined MPC's predecessor, Marathon Oil Company, in 1975 and held various leadership positions including head of Marathon's downstream operations beginning in 2001. Mr. Heminger was named president and CEO of Marathon Petroleum Corporation in 2011, and chairman in 2016.

Dan D. Sandman
Adjunct Professor, The Ohio State University Moritz College of Law. Mr. Sandman began his career at Marathon Oil Company in 1973 and served in various positions as an attorney before being appointed general counsel and secretary in 1986. He retired from United States Steel Corporation in 2007 as vice chairman of the board and chief legal and administrative officer.

C. Richard Wilson
Owner, Plough Penny Associates, LLC. Prior to Plough Penny, Mr. Wilson was an executive officer of Buckeye Partners, L.P., a petroleum pipeline company that became a master limited partnership in 1986. He served in various capacities at Buckeye and its general partner, including as president, chief operating officer, director and vice chairman.

COMPANY OFFICERS

Standing

Paula L. Rosson
Senior Vice President and Chief Accounting Officer

Molly R. Benson
Vice President, Corporate Secretary and Chief Compliance Officer

John S. Swearingen
Vice President, Crude Oil and Refined Products Pipelines

Gregory S. Floerke
Executive Vice President and Chief Operating Officer, MarkWest Operations

C. Corwin Bromley
Executive Vice President and General Counsel (Chief Legal Officer)

Timothy J. Aydt
Vice President, Operations (Marathon Pipeline Assets)

Frank A. Quintana
Vice President, Tax

Seated

Randy S. Nickerson
Executive Vice President and Chief Commercial Officer, MarkWest Assets

Donald C. Templin
President

Gary R. Heminger
Chairman and Chief Executive Officer

Pamela K.M. Beall
Executive Vice President and Chief Financial Officer

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(In millions, except per-unit, throughput and average tariff data)	**2016**	2015[5]	2014[5]
Revenues and other income	**$ 2,590**	$ 961	$ 793
Net income attributable to MPLX LP	**233**	156	121
Limited partners' interest in net income attributable to MPLX LP	**1**	99	115
Adjusted EBITDA attributable to MPLX LP[1][2]	**1,419**	498	166
Distributable cash flow (DCF)[1][2]	**1,140**	399	137
Net income per limited partner unit:			
Common units – basic	**$ 0**	$ 1.23	$ 1.55
Common units – diluted	**0**	1.22	1.55
Subordinated units – basic and diluted	**0**	0.11	1.50
Weighted average limited partner units outstanding:			
Common units – basic	**331**	79	37
Common units – diluted	**338**	80	37
Subordinated units – basic and diluted	**0**	18	37
Cash and cash equivalents	**$ 234**	$ 43	$ 27
Total assets	**16,646**	16,104	1,544
Total debt	**4,423**	5,264	644
Total equity	**10,319**	9,667	784
Capital expenditures:			
Maintenance	**68**	33	30
Growth[3]	**1,118**	282	124
Pipeline throughput (mbpd):			
Crude oil pipelines	**1,088**	1,061	1,041
Product pipelines	**908**	914	878
Total pipelines	**1,996**	1,975	1,919
Average tariff rates ($ per bbl.):			
Crude oil pipelines	**0.67**	0.66	0.64
Product pipelines	**0.69**	0.65	0.61
Total pipelines	**0.68**	0.65	0.63
Gathering and Processing throughputs[4]			
Natural gas processed (mmcf/d)	**5,761**	5,468	
C2+ NGLs fractionated (mbpd)	**335**	307	
Total gathering throughputs[4]	**3,275**	3,075	

(1) Financial measure not in accordance with U.S. generally accepted accounting principles (GAAP). See Results of Operations in the Management's Discussion and Analysis of Financial Conditions and Results of Operations section of the Form 10-K document for reconciliation to most directly comparable measures as reported in accordance with GAAP.
(2) Results for 2015 include MarkWest pre-merger EBITDA and undistributed distributable cash flow related to MarkWest's EBITDA and distributable cash flow from Oct. 1, 2015, to Dec. 3, 2015.
(3) See Reconciliation Data on Page 14.
(4) Throughputs for 2016 are for the full year and for 2015 are for the period Dec. 4, 2015, through Dec. 31, 2015. All throughputs are weighted averages for days in operation.
(5) Financial information has been retrospectively adjusted to include the results of the inland marine business prior to the March 31, 2016, acquisition from MPC, since MPLX and this business are under common control. The net income of the Predecessor is excluded from net income attributable to MPLX LP.

RECONCILIATION DATA

Reconciliation of adjusted EBITDA attributable to MPLX LP, and DCF attributable to GP and LP unitholders from net income (loss) (unaudited)

	Year Ended Dec. 31	
(In millions)	2016	2015
Net income	$ 258	$ 249
Depreciation and amortization	546	116
(Benefit) provision for income taxes	(12)	1
Amortization of deferred financing costs	46	5
Non-cash equity-based compensation	10	4
Impairment expense	130	–
Net interest and other financial costs	215	43
Loss (income) from equity investments	74	(3)
Distributions from unconsolidated subsidiaries	150	15
Unrealized derivative losses (gains) [(a)]	36	(4)
Acquisitions costs	(1)	30
Adjusted EBITDA	1,452	456
Adjusted EBITDA attributable to noncontrolling interests	(3)	(1)
Adjusted EBITDA attributable to Predecessor [(b)]	(30)	(119)
MarkWest's pre-merger EBITDA [(c)]	–	162
Adjusted EBITDA attributable to MPLX LP	1,419	498
Deferred revenue impacts	8	6
Net interest and other financial costs	(215)	(36)
Maintenance capital expenditures	(68)	(31)
Other	(4)	(6)
DCF pre-MarkWest undistributed	1,140	431
MarkWest undistributed DCF [(c)]	–	(32)
DCF	1,140	399
Preferred unit distributions	(41)	–
DCF attributable to GP and LP unitholders	$ 1,099	$ 399

(a) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record the realized gain or loss of the contract.
(b) The adjusted EBITDA adjustments related to the Predecessor are excluded from adjusted EBITDA attributable to MPLX LP and DCF prior to the March 31, 2016, acquisition.
(c) MarkWest pre-merger EBITDA and undistributed DCF relates to MarkWest's EBITDA and DCF from Oct. 1, 2015, through Dec. 3, 2015.

Reconciliation of adjusted EBITDA attributable to MPLX LP, and DCF attributable to GP and LP unitholders from net cash provided by operating activities (unaudited)

	Year Ended Dec. 31	
(In millions)	2016	2015
Net cash provided by operating activities	$ 1,288	$ 340
Changes in working capital items	(89)	54
All other, net	(20)	(12)
Non-cash equity-based compensation	10	4
Net gain on disposal of assets	1	–
Current income taxes	5	–
Net interest and other financial costs	215	43
Asset retirement expenditures	5	1
Unrealized derivative losses (gains) [(a)]	36	(4)
Acquisition costs	(1)	30
Other	2	–
Adjusted EBITDA	1,452	456
Adjusted EBITDA attributable to noncontrolling interests	(3)	(1)
Adjusted EBITDA attributable to Predecessor [(b)]	(30)	(119)
MarkWest's pre-merger EBITDA [(c)]	–	162
Adjusted EBITDA attributable to MPLX LP	1,419	498
Deferred revenue impacts	8	6
Net interest and other financial costs	(215)	(36)
Maintenance capital expenditures	(68)	(31)
Other	(4)	(6)
DCF pre-MarkWest undistributed	1,140	431
MarkWest's undistributed DCF [(c)]	–	(32)
DCF	1,140	399
Preferred unit distributions	(41)	–
DCF attributable to GP and LP unitholders	$ 1,099	$ 399

(a) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record the realized gain or loss of the contract.
(b) The adjusted EBITDA adjustments related to the Predecessor are excluded from adjusted EBITDA attributable to MPLX LP and DCF prior to the March 31, 2016, acquisition.
(c) MarkWest pre-merger EBITDA and undistributed DCF relates to MarkWest's EBITDA and DCF from Oct. 1, 2015, through Dec. 3, 2015.

Reconciliation Data continued on next page.

RECONCILIATION DATA

Reconciliation of Capital Expenditures (unaudited)

(In millions)	Year Ended Dec. 31 2016	2015
Capital Expenditures[a]:		
Maintenance	$ 68	$ 33
Growth	1,118	282
Total capital expenditures	**1,186**	**315**
Less: (Decrease) increase in capital accruals	(25)	26
Asset retirement expenditures	5	1
Additions to property, plant and equipment	**1,206**	**288**
Capital expenditures of unconsolidated subsidiaries[b]	131	24
Total gross capital expenditures	**1,337**	**312**
Less: Joint venture partner contributions	64	8
Total capital expenditures, net	**1,273**	**304**
Less: Maintenance capital	72	33
Total growth capital expenditures	**1,201**	**271**
Acquisition, net of cash acquired	–	1,218
Total growth capital and acquisition	**$ 1,201**	**$ 1,489**

(a) Includes capital expenditures of the Predecessor for all periods presented.
(b) Capital expenditures includes amounts related to unconsolidated, partnership operated subsidiaries.

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

Form 10-K

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

For the Fiscal Year Ended December 31, 2016

☐ **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 001-35714

MPLX LP

(Exact name of registrant as specified in its charter)

Delaware	**27-0005456**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

200 E. Hardin Street, Findlay, Ohio 45840
(Address of principal executive offices)

(419) 421-2414
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partnership Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐

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

The aggregate market value of common units held by non-affiliates as of June 30, 2016 was approximately $8.4 billion. Common units held by executive officers and directors of the registrant and its affiliates are not included in the computation. The registrant, solely for the purpose of this required presentation, has deemed its directors and executive officers and those of its affiliates to be affiliates.

MPLX LP had 357,257,661 common units, 3,990,878 Class B units and 7,372,419 general partner units outstanding at February 13, 2017.

DOCUMENTS INCORPORATED BY REFERENCE:

None

MPLX LP

Unless the context otherwise requires, references in this report to “MPLX LP,” “the Partnership,” “we,” “our,” “us,” or like terms refer to MPLX LP and its subsidiaries, including MPLX Operations LLC (“MPLX Operations”), MPLX Terminal and Storage LLC (“MPLX Terminal and Storage”), MarkWest Energy Partners, L.P. (“MarkWest”), MarkWest Hydrocarbon, L.L.C. (“MarkWest Hydrocarbon”), MPLX Pipe Line Holdings LLC (“Pipe Line Holdings”), Marathon Pipe Line LLC (“MPL”), Ohio River Pipe Line LLC (“ORPL”) and Hardin Street Marine LLC (“HSM”). We have partial ownership interests in a number of joint venture legal entities, including MarkWest Pioneer, L.L.C. (“MarkWest Pioneer”), MarkWest Utica EMG, L.L.C. (“MarkWest Utica EMG”) and its subsidiary Ohio Gathering Company, L.L.C. (“Ohio Gathering”), Ohio Condensate Company, L.L.C. (“Ohio Condensate”), Wirth Gathering Partnership (“Wirth”) and MarkWest EMG Jefferson Dry Gas Gathering Company, L.L.C. (“Jefferson Dry Gas”). References to “MPC” refer collectively to Marathon Petroleum Corporation and its subsidiaries, other than the Partnership. References to “Predecessor” refer collectively to HSM’s related assets, liabilities and results of operations.

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Glossary of Terms

The abbreviations, acronyms and industry technology used in this report are defined as follows.

ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ATM Program	A continuous offering, or at-the-market program, by which the Partnership may offer up to an aggregate of $1.2 billion of common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of any offerings, as defined by the prospectus supplement filed with the SEC on August 4, 2016
Bbl	Barrels
bcf/d	Billion cubic feet per day
Btu	One British thermal unit, an energy measurement
Condensate	A natural gas liquid with a low vapor pressure mainly composed of propane, butane, pentane and heavier hydrocarbon fractions
DCF (a non-GAAP financial measure)	Distributable Cash Flow
DOT	United States Department of Transportation
Dth/d	Dekatherms per day
EBITDA (a non-GAAP financial measure)	Earnings Before Interest, Taxes, Depreciation and Amortization
EIA	United States Energy Information Administration
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
Gal	Gallon
Gal/d	Gallons per day
IDR	Incentive distribution rights
Initial Offering	Initial public offering on October 12, 2012
IRS	Internal Revenue Service
LIBOR	London Interbank Offered Rate
mbbls	Thousands of barrels
mbpd	Thousand barrels per day
mcf	One thousand cubic feet of natural gas
MMBtu	One million British thermal units, an energy measurement
mmcf/d	One million cubic feet of natural gas per day
Net operating margin (a non-GAAP financial measure)	Segment revenue, less segment purchased product costs, less realized derivative gain (loss)
NGL	Natural gas liquids, such as ethane, propane, butanes and natural gasoline
NYSE	New York Stock Exchange
OTC	Over-the-Counter
Realized derivative gain/loss	The gain or loss recognized when a derivative matures or is settled
PADD	Petroleum Administration for Defense District
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPI	Producer Price Index
SEC	Securities and Exchange Commission
SMR	Steam methane reformer, operated by a third party and located at the Javelina gas processing and fractionation complex in Corpus Christi, Texas
Unrealized derivative gain/loss	The gain or loss recognized on a derivative due to changes in fair value prior to the instrument maturing or settling
USCG	United States Coast Guard
VIE	Variable interest entity
WTI	West Texas Intermediate

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. Business, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk, includes forward-looking statements. You can identify our forward-looking statements by words such as "anticipate," "believe," "design," "estimate," "objective," "expect," "forecast," "goal," "guidance," "imply," "intend," "opportunity," "outlook," "plan," "position," "potential," "predict," "project," "prospective," "pursue," "seek," "strategy," "target," "could," "may," "should," "would," "will" or other similar expressions that convey the uncertainty of future events or outcomes. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include, but are not limited to, statements that relate to, or statements that are subject to risks, contingencies or uncertainties that relate to:

- future levels of revenues and other income, income from operations, net income attributable to MPLX LP, earnings per unit, Adjusted EBITDA or DCF (please read Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Information for the definitions of Adjusted EBITDA and DCF);
- anticipated levels of regional, national and worldwide prices of crude oil, natural gas, NGLs and refined products;
- anticipated levels of drilling activity, production rates and volumes of throughput of crude oil, natural gas, NGLs, refined products or other hydrocarbon-based products;
- future levels of capital, environmental or maintenance expenditures, general and administrative and other expenses;
- the success or timing of completion of ongoing or anticipated capital or maintenance projects;
- expectations regarding the MarkWest Merger (as defined below), joint venture arrangements and other acquisitions, including the dropdowns proposed by MPC, or divestitures of assets;
- business strategies, growth opportunities and expected investments;
- the effect of restructuring or reorganization of business components;
- the potential effects of judicial or other proceedings on our business, financial condition, results of operations and cash flows;
- the potential effects of changes in tariff rates on our business, financial condition, results of operations and cash flows;
- the adequacy of our capital resources and liquidity, including, but not limited to, availability of sufficient cash flow to pay distributions and execute our business plan;
- our ability to successfully implement our growth strategy, whether through organic growth or acquisitions;
- capital market conditions, including the cost of capital, and our ability to raise adequate capital to execute our business plan and implement our growth strategy; and
- the anticipated effects of actions of third parties such as competitors, or federal, foreign, state or local regulatory authorities, or plaintiffs in litigation.

We have based our forward-looking statements on our current expectations, estimates and projections about our industry and our partnership. We caution that these statements are not guarantees of future performance and you should not rely unduly on them, as they involve risks, uncertainties and assumptions that we cannot predict. In addition, we have based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. While our management considers these assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, our actual results may differ materially from the future performance that we have expressed or forecast in our forward-looking statements. Differences between actual results and any future performance suggested in our forward-looking statements could result from a variety of factors, including the following:

- changes in general economic, market or business conditions;
- changes in the economic and financial condition of MPLX LP;
- risks and uncertainties associated with intangible assets, including any future goodwill or intangible assets impairment charges;
- changes in producer customers' drilling plans or in volumes of throughput of crude oil, natural gas, NGLs, refined products or other hydrocarbon-based products;
- changes in regional, national and worldwide prices of crude oil, natural gas, NGLs and refined products;
- domestic and foreign supplies of crude oil and other feedstocks, natural gas, NGLs and refined products such as gasoline, diesel fuel, jet fuel, home heating oil and petrochemicals;
- foreign imports and exports of crude oil, refined products, natural gas and NGLs;
- midstream and refining industry overcapacity or undercapacity;
- changes in the cost or availability of third-party vessels, pipelines, railcars and other means of transportation for crude oil, natural gas, NGLs, feedstocks and refined products;
- price, availability and acceptance of alternative fuels and alternative-fuel vehicles and laws mandating such fuels or vehicles;
- fluctuations in consumer demand for refined products, natural gas and NGLs, including seasonal fluctuations;
- changes in maintenance capital expenditure requirements or changes in costs of planned capital projects;
- political and economic conditions in nations that consume refined products, natural gas and NGLs, including the United States, and in crude oil producing regions, including the Middle East, Africa, Canada and South America;
- actions taken by our competitors and the expansion and retirement of pipeline, processing, fractionation and treating capacity in response to market conditions;
- changes in fuel and utility costs for our facilities;
- failure to realize the benefits projected for capital projects, or cost overruns associated with such projects;
- the ability to successfully implement growth strategies, whether through organic growth or acquisitions;
- the time, costs and ability to obtain regulatory and other approvals, waivers or consents required to consummate the strategic initiatives proposed by MPC, such as the proposed accelerated dropdown of assets to MPLX LP;
- accidents or other unscheduled shutdowns affecting our pipelines, processing, fractionation and treating facilities or equipment, or those of our suppliers or customers or facilities upstream or downstream of our facilities;

- unusual weather conditions and natural disasters;
- disruptions due to equipment interruption or failure;
- acts of war, terrorism or civil unrest that could impair our ability to gather, process, fractionate or transport crude oil, natural gas, NGLs or refined products;
- legislative or regulatory action, which may adversely affect our business or operations;
- rulings, judgments or settlements in litigation or other legal, tax or regulatory matters, including unexpected environmental remediation costs, in excess of any reserves or insurance coverage;
- political pressure and influence of environmental groups upon policies and decisions related to the production, gathering, processing, fractionation, refining, transportation and marketing of natural gas, oil, NGLs or other carbon-based fuels;
- labor and material shortages;
- the ability and willingness of parties with whom we have material relationships to perform their obligations to us;
- capital market conditions, including a persistence or increase of the current yield on MPLX LP common units, adversely affecting MPLX LP's ability to meet its distribution growth guidance;
- increases in and availability of equity capital, changes in the availability of unsecured credit and changes affecting the credit markets generally; and
- the other factors described in Item 1A. Risk Factors.

We undertake no obligation to update any forward-looking statements except to the extent required by applicable law.

Part I

Item 1. Business

OVERVIEW

We are a diversified, growth-oriented master limited partnership ("MLP") formed in 2012 by MPC to own, operate, develop and acquire midstream energy infrastructure assets. We are engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs; and the gathering, transportation and storage of crude oil and refined petroleum products.

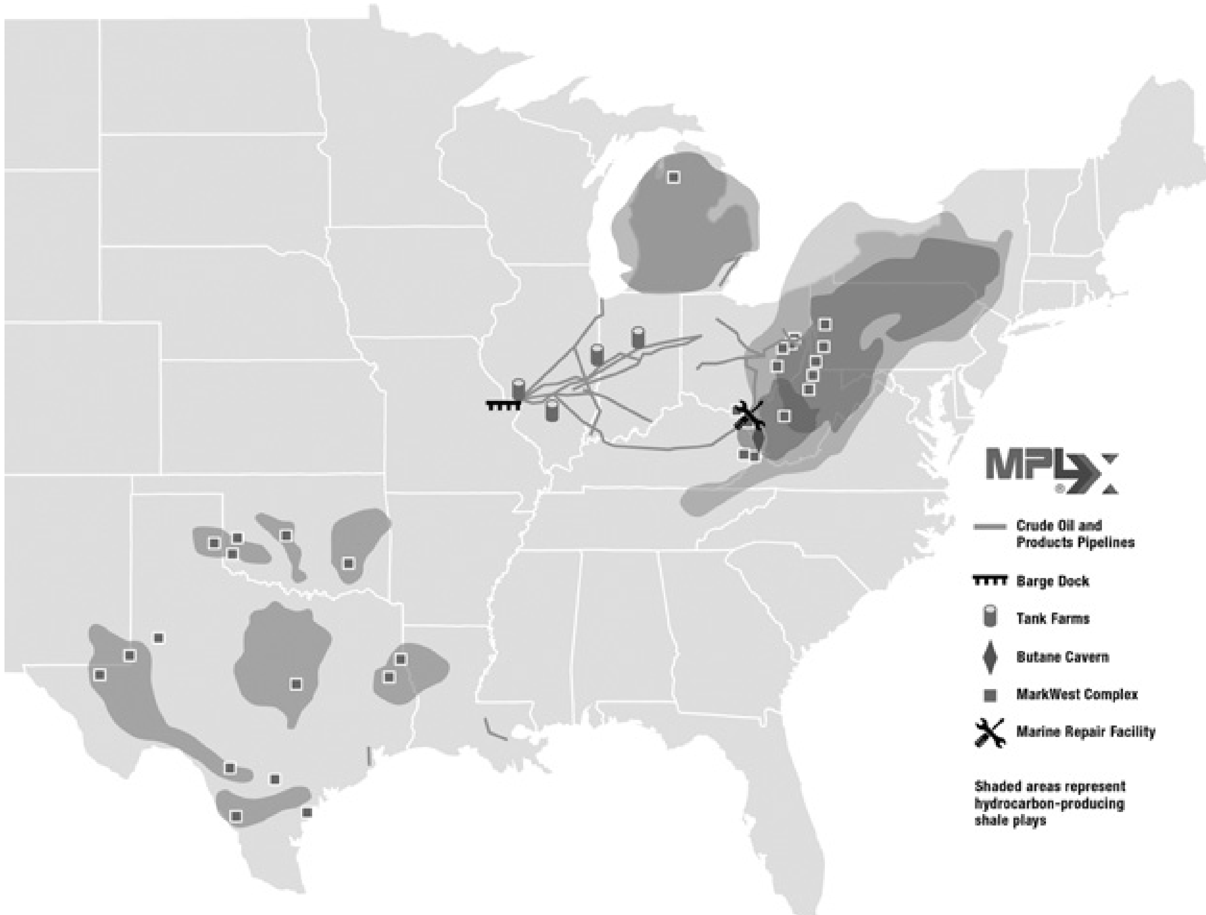
Our assets include infrastructure to support MPC including approximately 2,900 miles of crude oil and refined product pipelines across nine states. We own a barge dock facility with approximately 78 mbpd of crude oil and refined product throughput capacity, as well as crude oil and product storage facilities (tank farms) with approximately 4,533 mbbls of available storage capacity. We also own a butane cavern with approximately 1,000 mbbls of available storage capacity. Effective March 31, 2016, the Partnership acquired MPC's inland marine business, comprised of 18 tow boats and 205 tank barges. This business is operated through HSM and the related assets, liabilities and results of operations are collectively referred to as the "Predecessor." On December 4, 2015, we completed the merger with MarkWest (the "MarkWest Merger"), which is one of the largest processors of natural gas in the United States and the largest processor and fractionator in the Marcellus and Utica shale plays. These assets include gathering and processing infrastructure of more than 5,600 miles of gas and NGL pipelines, 54 gas processing plants, 14 NGL fractionation facilities and two condensate stabilization facilities.

MPC is our sponsor and a large source of our revenues. We have multiple transportation and storage services agreements with MPC. These agreements are long-term, fee-based agreements with minimum volume commitments and, therefore, MPC will continue to be an important source of our revenues for the foreseeable future. Furthermore, as a result of the MarkWest Merger, we also have long-term relationships with a diverse set of producer customers in many natural gas resource plays including the Marcellus Shale, Utica Shale, Huron/Berea Shale, Haynesville Shale, Woodford Shale, Granite Wash formation and the Permian Basin.

As of February 13, 2017, MPC owned our general partner, MPLX GP LLC ("MPLX GP"), and the associated incentive distribution rights, in addition to an approximate 23.5 percent limited partner interest (including the Class B units on an as-converted basis) in us. Given MPC's significant interest in us, and its stated intent to grow its midstream business, MPC has recently announced plans to offer its MLP-qualifying assets estimated to generate $1.4 billion of annual EBITDA from its portfolio of midstream assets. MPC expects to offer us these assets as soon as practicable in 2017, subject to market conditions, requisite approvals and regulatory clearances, including tax. In conjunction with the completion of the announced dropdowns, MPC also expects to exchange its economic interests in MPLX GP for newly issued MPLX LP units in order to optimize the Partnership's cost of capital. We also have significant organic growth opportunities to expand midstream services throughout major shale plays in the United States. Furthermore, we may pursue third-party midstream acquisitions independently or with MPC to complement our existing geographic footprint or expand our activities into new areas. MPC is under no obligation, however, to offer to sell us additional assets or to pursue acquisitions cooperatively with us, and we are under no obligation to acquire any such additional assets or pursue any such cooperative acquisitions.

Finally, we have an investment grade credit profile that provides the Partnership strong financial flexibility in order to fund growth projects and execute its strategic plans.

We conduct our operations in the following operating segments: Logistics and Storage ("L&S") and Gathering and Processing ("G&P"). For more information on these segments, see Our Operating Segments discussion below. The following map details our individual assets:



The following table summarizes the operating performance for each segment for the year ended December 31, 2016. For further discussion of our segments and a reconciliation to our Consolidated Statements of Income, see Item 8. Financial Statements and Supplementary Data—Note 10.

	2016		
(In millions)	L&S	G&P	Total
Revenues and other income:			
Segment revenues	$787	$2,185	$2,972
Segment other income	68	1	69
Total segment revenues and other income	855	2,186	3,041
Costs and expenses:			
Segment cost of revenues	368	907	1,275
Segment operating income before portion attributable to noncontrolling interest and Predecessor	487	1,279	1,766
Segment portion attributable to noncontrolling interest and Predecessor	34	147	181
Segment operating income attributable to MPLX LP	$453	$1,132	$1,585

RECENT DEVELOPMENTS

On March 14, 2016, the Partnership entered into a Membership Interests Contribution Agreement (the "Contribution Agreement") with MPLX GP, MPLX Logistics Holdings LLC and MPC Investment LLC ("MPC Investment"), each a wholly-owned subsidiary of MPC, related to the acquisition of HSM, MPC's inland marine business, from MPC. Pursuant to the Contribution Agreement, the transaction was valued at $600 million consisting of a fixed number of common units and general partner units. The general partner units maintained MPC's two percent general partner interest in the Partnership. The acquisition closed on March 31, 2016. MPC waived distributions in the first quarter of 2016 on MPLX LP common units issued in connection with this transaction.

The inland marine business, which transports light products, heavy oils, crude oil, renewable fuels, chemicals and feedstocks in the Midwest and U.S. Gulf Coast regions, accounted for nearly 60 percent of the total volumes MPC shipped by inland marine vessels as of March 31, 2016. The Partnership accounts for HSM as a reporting unit of the L&S segment. See Item 8. Financial Statements and Supplementary Data—Note 4 for more information on this transaction.

On May 13, 2016, MPLX LP completed the private placement of approximately 30.8 million 6.5 percent Series A Convertible Preferred units (the "Preferred units") for a cash purchase price of $32.50 per unit. The aggregate net proceeds of approximately $984 million from the sale of the Preferred units were used for capital expenditures, repayment of debt and general partnership purposes. The Preferred units rank senior to all common units with respect to distributions and rights upon liquidation. The holders of the Preferred units are entitled to receive cumulative quarterly distributions equal to $0.528125 per unit commencing for the quarter ended June 30, 2016, with a prorated amount from the date of issuance. Following the second anniversary of the issuance of the Preferred units, the holders of the Preferred units will receive as a distribution the greater of $0.528125 per unit or the amount of per unit distributions paid to common units. See Item 8. Financial Statements and Supplementary Data—Note 9 for more information on this transaction.

On August 4, 2016, MPLX LP entered into a Second Amended and Restated Distribution Agreement (the "Distribution Agreement") providing for the continuous issuance of MPLX LP common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of any offerings (such continuous offering program, or at-the-market program, referred to as the "ATM Program"). MPLX LP expects to use the net proceeds from sales under the ATM Program for general partnership purposes including repayment of debt and funding for acquisitions, working capital requirements and capital expenditures.

During the year ended December 31, 2016, the Partnership issued an aggregate of 26 million common units under the ATM Program generating net proceeds of approximately $776 million. As of December 31, 2016, $717 million of common units remains available for issuance through the ATM Program under the Distribution Agreement.

On September 1, 2016, the Partnership and various affiliates initiated a series of reorganization transactions in order to simplify the Partnership's ownership structure and its financial and tax reporting requirements (the "Class A Reorganization"). In connection with these transactions, all of the issued and outstanding MPLX LP Class A units, all of which were held by MarkWest Hydrocarbon (MarkWest Hydrocarbon, Inc. prior to the Class A Reorganization), were either distributed to or purchased by MPC in exchange for $84 million in cash and a fixed number of MPLX LP common units and MPLX LP general partner units. Following these preparatory transactions, all of the MPLX LP Class A units were exchanged on a one-for-one basis for newly issued common units representing limited partner interests in MPLX LP. MPC also contributed $141 million to facilitate the repayment of intercompany debt between MarkWest Hydrocarbon and MarkWest. As a result of these transactions, the MPLX LP Class A units were eliminated, are no longer outstanding and no longer participate in distributions of cash from the Partnership. Cash that is derived from or attributable to MarkWest Hydrocarbon's operations is now treated in the same manner as cash derived from or attributable to other operations of the Partnership and its subsidiaries. See Item 8. Financial Statements and Supplementary Data—Note 8 for more information on this transaction.

On October 11, 2016, the Cornerstone Pipeline became fully operational and in December 2016, the Hopedale pipeline connection was completed. This project is reported within our L&S segment. This pipeline is designed to transport condensate and natural gasoline from origination facilities in Harrison County, OH, to a tank farm in East Sparta, OH, where the condensate and natural gasoline can then continue on to MPC's refinery in Canton, OH. The completion of this key organic growth project has created transportation and marketing options for Utica and Marcellus shale production. Additional pipelines are currently under construction and will provide further distribution to the Midwest and Canada.

On January 3, 2017, MPC announced its plans to offer the Partnership the opportunity to acquire assets contributing an estimated $1.4 billion of annual EBITDA in 2017. These planned dropdowns are subject to market conditions, requisite approvals and regulatory clearances, including tax clearance.

On December 5, 2016, MPC offered up to 100 percent of MPLX Terminals LLC ("MPLX Terminals"), Hardin Street Transportation LLC ("Hardin Street Transportation") and Woodhaven Cavern LLC ("Woodhaven Cavern") to MPLX. MPLX Terminals owns and operates light products terminals. Hardin Street Transportation owns and operates various private crude oil and refined product pipeline systems and associated storage tanks. Woodhaven Cavern owns and operates butane and propane storage caverns. The transaction is expected to close in the first quarter of 2017, pending requisite approvals.

The Partnership's plans for funding these dropdowns would likely include debt and equity in approximately equal proportions, with the equity financing to be funded through transactions with MPC. In February 2017, we issued an additional $2.25 billion aggregate principal amount of senior notes, as described below. In addition to the expected dropdowns, MPC announced its intentions to offer to exchange its IDRs for MPLX LP units in conjunction with the completion of the dropdowns in order to reduce the Partnership's cost of capital.

On January 25, 2017, we announced the board of directors of our general partner had declared a distribution of $0.5200 per unit that was paid on February 14, 2017 to unitholders of record on February 6, 2017.

On February 6, 2017, the Partnership and Antero Midstream Partners LP ("Antero Midstream") formed a strategic joint venture to support Antero Resources Corporation ("Antero Resources") in the Marcellus Shale. Antero Midstream Partners released to the joint venture its dedication from Antero Resources of approximately 195,000 gross operated acres located in Tyler, Wetzel and Ritchie counties of West Virginia. The joint venture will support the ongoing development of incremental gas processing required by Antero Resources in the Marcellus Shale. The joint venture is also investing in fractionation capacity at MarkWest's Hopedale Complex in Ohio and has an option to invest in future fractionation expansions that support Antero Resources' liquids production. See Item 8. Financial Statements and Supplementary Data—Note 24 for additional information.

On February 10, 2017, the Partnership completed a public offering of $1.25 billion aggregate principal amount of 4.125 percent unsecured senior notes due March 2027 (the "2027 Senior Notes") and $1.0 billion aggregate principal amount of 5.200 percent unsecured senior notes due March 2047 (the "2047 Senior Notes" and, collectively with the 2027 Senior Notes, the "New Senior Notes"). The 2027 Senior Notes and the 2047 Senior Notes were offered at a price to the public of 99.834 percent and 99.304 percent of par, respectively. The Partnership intends to use the net proceeds from this offering for general partnership purposes, which may include, from time to time, acquisitions (including the previously announced planned dropdown of assets from MPC, the acquisition of the Ozark pipeline, and the acquisition of a partial, indirect equity interest in the Bakken Pipeline system) and capital expenditures. See Item 8. Financial Statements and Supplementary Data—Note 24 for additional information.

On February 13, 2017, the Partnership announced that it has entered into an asset purchase agreement with Enbridge Pipelines (Ozark) LLC ("Enbridge Ozark"), under which an affiliate of Pipe Line Holdings has agreed to purchase the Ozark pipeline for approximately $220 million from Enbridge Ozark. The Ozark pipeline is a 433-mile, 22-inch crude oil pipeline originating in Cushing, Oklahoma, and terminating in Wood River, Illinois, capable of transporting approximately 230,000 barrels per day. This purchase transaction is expected to close in the first quarter of 2017. See Item 8. Financial Statements and Supplementary Data—Note 24 for additional information.

On February 15, 2017, the Partnership closed on its previously announced intent to participate in a joint venture with Enbridge Energy Partners L.P. ("Enbridge Energy Partners") to acquire a 9.1875 percent indirect interest in the Dakota Access Pipeline ("DAPL") and Energy Transfer Crude Oil Company Pipeline ("ETCOP") projects, collectively referred to as the Bakken Pipeline system, from Energy Transfer Partners, L.P. ("ETP") and Sunoco Logistics Partners, L.P. ("SXL") for $500 million. Furthermore, MPC expects to become a committed shipper on the Bakken Pipeline system under terms of an on-going open season. The Bakken Pipeline system is currently expected to deliver in excess of 470,000 barrels per day of crude oil from the Bakken/Three Forks production area in North Dakota to the Midwest through Patoka, Illinois and ultimately to the Gulf Coast. ETP and SXL collectively own a 75 percent interest in each of the two joint ventures that are developing the Bakken Pipeline system. MPLX LP and Enbridge Energy Partners intend to form a new joint venture to acquire 49 percent of ETP and SXL's 75 percent indirect interest in the Bakken Pipeline system. MPLX LP will own 25 percent of this new joint venture with Enbridge, which results in its 9.1875 percent indirect ownership interest in the Bakken Pipeline system. The Partnership expects to account for its investment using the equity method of accounting. See Item 8. Financial Statements and Supplementary Data—Note 24 for additional information.

BUSINESS STRATEGIES

Our primary business objectives are to enhance unitholder returns through the generation of stable cash flows. We intend to accomplish these objectives by executing the following strategies:

Maintain Long-Term Integrated Relationships with Our Producer Customers. We develop long-term integrated relationships with our producer customers. Our relationships are characterized by an intense focus on customer service and a deep understanding of our producer customers' requirements coupled with the ability to increase the level of our midstream services in response to their midstream requirements. Through collaborative planning, we construct midstream infrastructure and provide unique solutions that are critical to the ongoing success of our producer customers' development plans. As a result of delivering high-quality midstream services, MarkWest has been a top-rated midstream service provider since 2006 as determined by an independent research provider.

Grow through Acquisitions. In addition to the MarkWest Merger and HSM acquisition, we plan to continue pursuing acquisitions of complementary assets from MPC as well as third parties, such as the Ozark pipeline acquisition and the acquisition of the joint venture interest in the Bakken Pipeline system. As discussed above, we announced that we expect to acquire assets from MPC with an estimated $1.4 billion of annual EBITDA as soon as practicable, subject to requisite approvals, and regulatory clearance, including tax. We may also pursue third-party midstream acquisitions independently or with MPC that complement our existing geographic footprint or expand our activities into new areas.

Increase Operating Cash Flow and Pursue Organic Growth Opportunities. We intend to increase operating cash flow by continuing to grow in our primary areas of operation to meet anticipated demand for additional midstream services. In addition, we intend to increase operating cash flow by evaluating and capitalizing on organic investment opportunities that may arise in our areas of operations and increasing the utilization of our existing facilities by providing additional services for new and existing customers. We will evaluate organic growth projects both within our geographic footprint as well as in new areas that we consider strategic. With the support of MPC as our sponsor, we have the ability to develop incremental infrastructure to support growth across the hydrocarbon value chain.

Focus on Fee-Based Businesses. We are focused on generating stable cash flows by providing fee-based midstream services to our customers. For the full year ending December 31, 2017, we expect fee-based contracts to be approximately 95 percent of our net operating margin (for more information on net operating margin, which is a non-GAAP measure, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures).

Sustain Long-Term Growth. Our goal is to maintain an attractive distribution growth profile over the long term. Since the Initial Offering, we have increased our distribution for 16 consecutive quarters, which represents a compound annual growth rate of 18.6 percent over the minimum quarterly distribution. Our goal is to also optimize our cost of capital by maintaining an investment grade credit profile, providing visibility to future growth, and eliminating IDR distributions to MPC. On January 3, 2017, we announced that we expect to exchange MPLX LP units for MPC's economic interests in MPLX GP, including IDR's, in conjunction with the completion of the MPC asset acquisitions described above. We believe our plans, along with the support of our sponsor, provide multiple avenues to support our distribution growth profile over the long-term.

Maintain Safe and Reliable Operations. We believe that providing safe, reliable and efficient services is a key component in generating stable cash flows, and we are committed to maintaining and improving the safety, reliability and efficiency of our operations. We intend to continue promoting a high standard for safety and environmental stewardship.

COMPETITIVE STRENGTHS

We believe we are well positioned to execute our business strategies based on the following competitive strengths:

Strategically Located Assets. Our L&S segment assets are primarily located in the Midwest and Gulf Coast regions of the United States and our G&P segment assets are primarily located in the Northeast and Southwest regions of the United States.

- Our L&S assets are strategically located and collectively comprise approximately 81 percent of total United States crude distillation capacity and approximately 81 percent of total United States finished products demand for the year ended December 31, 2016, according to the EIA. These assets are integral to the success of MPC's operations, which include seven refineries in the Midwest and Gulf Coast regions of the United States with an aggregate crude oil refining capacity of approximately 1.8 million barrels per calendar day.

- Our G&P segment is focused on regions of natural gas supply growth. We are one of the largest processors and fractionators in the United States.
    - We are the largest processor and fractionator in the Marcellus and Utica shale plays. As of February 13, 2017, our assets in the northeastern United States have combined processing capacity of approximately 6.1 bcf/d and combined fractionation capacity of approximately 518 mbpd as well as an integrated NGL pipeline network and extensive logistics and marketing infrastructure. We believe our significant asset base and full-service midstream model provides us with strategic competitive advantages in capturing and contracting for gathering, processing and fractionating of new supplies of natural gas as production in the Northeast continues to increase.
    - We also have a significant presence in the southwestern portion of the United States with an existing strong competitive position; access to a significant reserve or customer base with a stable or growing production profile; ample opportunities for long-term continued organic growth; ready access to markets; and close proximity to other expansion opportunities. We have 1.4 bcf/d of processing capacity in the southwestern portion of the United States.

Leading Midstream Positions Drive Investment Opportunities. Our organic growth capital plan range for 2017 is $1.4 billion to $1.7 billion, which does not include the anticipated dropdowns or acquisitions previously discussed or their respective subsequent capital spending. The G&P segment capital plan includes investments that are expected to support producer customers. During 2017, we expect to complete 400 mmcf/d of additional natural gas processing capacity and 120 mbpd of additional fractionation capacity (of which 60 mbpd of fractionation capacity has already been completed), primarily in the Marcellus Shale. The L&S segment capital plan includes the development of various crude oil and refined petroleum products infrastructure projects, including a build out of Utica Shale infrastructure in connection with the recently completed Cornerstone Pipeline, a butane cavern and a tank farm expansion. We also have large organic growth prospects associated with the anticipated growth of MPC’s operations and third-party activity in our areas of operation that will provide attractive returns and cash flows. We also plan to pursue acquisitions of other midstream assets on a standalone basis or cooperatively with MPC.

Strategic Relationship with MPC. We have a strategic relationship with MPC and MPC views us as integral to its operations and is aligned with our success. We believe MPC to be the largest crude oil refiner in the Midwest and the third-largest in the United States based on crude oil refining capacity. MPC is well-capitalized, with investment grade credit ratings, and owns our general partner, an approximate 23.5 percent limited partner interest (including the Class B units on an as-converted basis) as of February 13, 2017 and all of our incentive distribution rights. We expect to acquire a portfolio of midstream assets from MPC, as recently announced in its plan to dropdown an estimated $1.4 billion of EBITDA in 2017, subject to regulatory and tax clearance. In conjunction with the completion of the announced dropdowns, MPC also expects to exchange its economic interest in MPLX GP for newly issued MPLX LP units in order to optimize the Partnership’s cost of capital. We believe that our relationship with MPC will provide us with significant growth opportunities, as well as a base of stable cash flows.

High-Quality, Well-Maintained Asset Base. We continually invest in the maintenance and integrity of our assets and have developed various programs to help us efficiently monitor and maintain them. For example, we utilize MPC’s patented integrity management program that employs state-of-the-art mechanical integrity inspection and repair programs to enhance the safety of certain of our pipelines.

Stable and Predictable Cash Flows. We generate a substantial majority of our revenue through long-term, fee-based agreements. We believe our long-term contracts, which we define as contracts with remaining terms of four years or more, lend greater stability to our cash flow profile. The table below provides long-term contract details by segment as of December 31, 2016:

	Remaining contract term	% of volumes
L&S segment	6 years	72%
G&P segment	4 to 19 years	85%

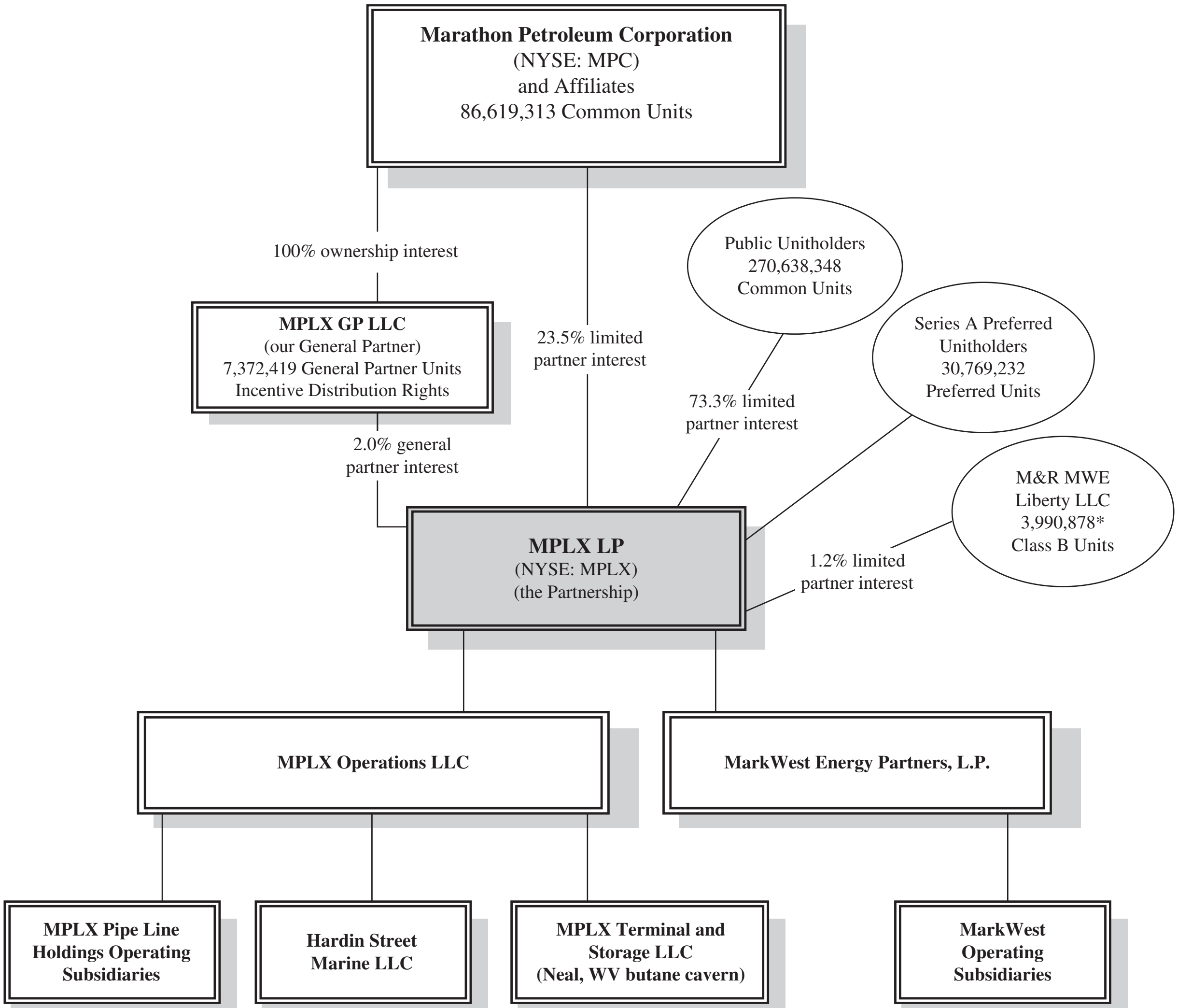
Financial Flexibility. As of December 31, 2016, we had $234 million of cash and $2.5 billion available on our revolving credit facilities. We believe that we will have the financial flexibility to execute our growth strategy through excess cash reserves, borrowing capacity under our revolving credit facilities and access to the debt and equity capital markets. See Item 8. Financial Statements and Supplementary Data—Note 17 and Note 8 for additional information regarding our recent transactions related to debt and common unit offerings.

Experienced Management Team. Our management team has substantial experience in the management and operation of midstream assets. Our management team also has expertise in acquiring and integrating assets as well as executing growth strategies in the midstream sector.

The above discussion contains forward-looking statements with respect to the business and operations of MPLX LP, including our investment in the Ozark pipeline, the Bakken Pipeline system, the Cornerstone Pipeline, the joint venture with Antero Midstream Partners, LP, the strategic initiatives announced by MPC, our plans for funding the dropdowns, the ATM Program, our business strategies, competitive strengths and the Partnership's capital budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include negative capital market conditions, including a persistence or increase of the current yield on common units, which is higher than historical yields, adversely affecting the Partnership's ability to meet its distribution growth guidance; the time, costs and ability to obtain regulatory or other approvals and consents and otherwise consummate the strategic initiatives discussed herein and other proposed transactions; the satisfaction or waiver of conditions in the agreements governing the strategic initiatives discussed herein and other proposed transactions; our ability to achieve the strategic and other objectives related to the strategic initiatives discussed herein, including the dropdowns proposed by MPC and other proposed transactions; adverse changes in laws including with respect to tax and regulatory matters; inability to agree with respect to the timing of and value attributed to assets identified for dropdown; the adequacy of the Partnership's capital resources and liquidity, including, but not limited to, availability of sufficient cash flow to pay distributions, and the ability to successfully execute its business plans and growth strategy; continued/further volatility in and/or degradation of market and industry conditions; changes to the expected construction costs and timing of projects; completion of midstream infrastructure by competitors; disruptions due to equipment interruption or failure, including electrical shortages and power grid failures; the suspension, reduction or termination of MPC's obligations under the Partnership's commercial agreements; modifications to earnings and distribution growth objectives; the level of support from MPC, including dropdowns, alternative financing arrangements, taking equity units, and other methods of sponsor support, as a result of the capital allocation needs of the enterprise as a whole and its ability to provide support on commercially reasonable terms; compliance with federal and state environmental, economic, health and safety, energy and other policies and regulations and/or enforcement actions initiated thereunder; changes to the Partnership's capital budget; prices of and demand for natural gas, NGLs, crude oil and refined products, delays in obtaining necessary third-party approvals and governmental permits, changes in labor, material and equipment costs and availability, planned and unplanned outages, the delay of, cancellation of or failure to implement planned capital projects, project overruns, disruptions or interruptions of our operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations. These factors, among others, could cause actual results to differ materially from those set forth in the forward-looking statements. For additional information on forward-looking statements and risks that can affect our business, see "Disclosures Regarding Forward-Looking Statements" and Item 1A. Risk Factors in this Annual Report on Form 10-K.

ORGANIZATIONAL STRUCTURE

The following diagram depicts our organizational structure and MPC's ownership interests in us as of February 13, 2017.



We are an MLP with outstanding common units, Preferred units, and Class B units.

- Our common units are publicly traded on the NYSE under the symbol "MPLX."
- The Preferred units rank senior to all common units with respect to distributions and rights upon liquidation. The holders of the Preferred units are entitled to receive cumulative quarterly distributions equal to $0.528125 per unit commencing for the quarter ended June 30, 2016, with a prorated amount from the date of issuance. Following the second anniversary of the issuance of the Preferred units, the holders of the Preferred units will receive as a distribution the greater of $0.528125 per unit or the amount of per unit distributions paid to common units. The purchasers may convert their Preferred units into common units, at any time after the third anniversary of the issuance date or prior to liquidation, dissolution or winding up of the Partnership, in full or in part, subject to minimum conversion amounts and conditions. After the fourth anniversary of the issuance date, the Partnership may convert the Preferred units into common units at any time, in whole or in part, subject to certain minimum conversion amounts and conditions, if the closing price of MPLX LP common units is

greater than $48.75 for the 20 day trading period immediately preceding the conversion notice date. The conversion rate for the Preferred units shall be the quotient of (a) the sum of (i) $32.50, plus (ii) any unpaid cash distributions on the applicable Preferred unit, divided by (b) $32.50. The holders of the Preferred units are entitled to vote on an as-converted basis with the common unitholders and will have certain other class voting rights with respect to any amendment to the partnership agreement that would adversely affect any rights, preferences or privileges of the Preferred units. In addition, upon certain events involving a change in control the holders of Preferred units may elect, among other potential elections, to convert their Preferred units to common units at the then change of control conversion rate.

- All of the Class B units were issued to and are held by M&R MWE Liberty LLC and certain of its affiliates ("M&R"), an affiliate of The Energy & Minerals Group ("EMG"). Each Class B unit of MarkWest issued and outstanding immediately prior to the effective time of the MarkWest Merger was converted into the right to receive one Class B unit of MPLX LP. Each Class B unit of MPLX LP will convert into 1.09 common units of MPLX LP and the right to receive $6.20 in cash, and the conversion of the Class B units will occur in equal installments, the first of which occurred on July 1, 2016 and the second of which will occur on July 1, 2017. Class B units (i) share in our taxable income and losses, (ii) are not entitled to participate in any distributions of available cash prior to their conversion and (iii) do not have the right to vote on, approve or disapprove, or otherwise consent to or not consent to any matter (including mergers, unit exchanges and similar statutory authorizations) other than those matters that disproportionately and adversely affect the rights and preferences of the Class B units. Upon conversion of the Class B units, the right of M&R and certain of its affiliates to vote as a common unitholder of the Partnership will be limited to a maximum of five percent of the Partnership's outstanding common units. Upon the conversion of each tranche of Class B units, M&R will have the right with respect to such converted units to participate in the Partnership's underwritten offerings of our common units including continuous equity or similar programs in an amount up to 20 percent of the total number of common units offered by the Partnership. In addition, M&R may freely transfer such converted units, and M&R will have the right to demand that we conduct up to three underwritten offerings beginning in 2017, but restricted to no more than one offering in any twelve-month period. M&R is not permitted to transfer its Class B units without the prior written consent of our general partner's board of directors.

INDUSTRY OVERVIEW

We provide diversified services in the midstream sector across the hydrocarbon value chain. The types of midstream services provided by both our L&S and G&P segments are as follows:

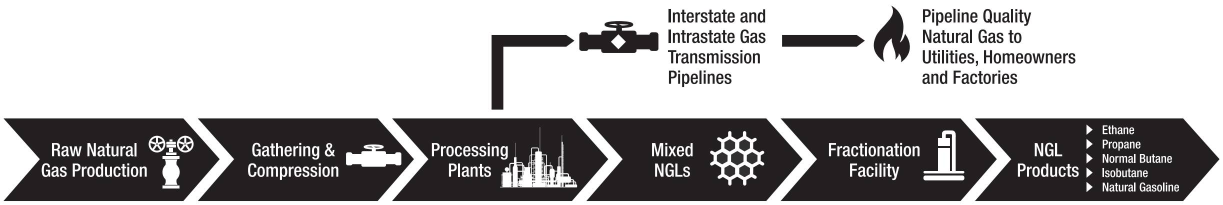
L&S:

Our L&S assets are integral to the success of MPC's operations related to transportation and storage across the hydrocarbon value chain.

- *Logistics*. Crude oil is the primary raw material for transportation fuels and the basis for many products including plastics and petrochemicals, in addition to heating oil for homes once it is refined and prepared for use. While many forms of transportation are used to move this product to storage hubs and refineries, we believe pipelines and marine vessels are among the safest, most efficient and cost-effective ways to move this resource to refineries and to market. Pipelines bring advantaged North American crude oil from the upper Great Plains, Texas and Canada to numerous refiners. Pipelines and marine vessels are also used to effectively move refined products from refineries to customers and end markets.
- *Storage*. The hydrocarbon market is often volatile and the ability to take advantage of fast moving market conditions is enhanced by our ability to store crude oil and other hydrocarbon-based products at our tank farms and butane cavern. Storage facilities provide flexibility and logistics optionality, which enhances MPC's ability to maximize returns for refined products.

G&P:

The midstream natural gas industry is the link between the exploration for and production of natural gas and the delivery of its hydrocarbon components to end-use markets, and the components of this value chain are graphically depicted and further described below:



- *Gathering.* The natural gas production process begins with the drilling of wells into gas-bearing rock formations. At the initial stages of the midstream value chain, a network of pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport raw, or untreated, natural gas to a central location for treating and processing. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are typically designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow gathering of additional production without significant incremental capital expenditures.
  - *Compression.* Natural gas compression is a mechanical process in which a volume of natural gas at a given pressure is compressed to a desired higher pressure, which allows the natural gas to be gathered more efficiently and delivered into a higher pressure system, processing plant or pipeline. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver natural gas into a higher pressure system. Since wells produce at progressively lower field pressures as they deplete, field compression is needed to maintain throughput across the gathering system.
  - *Treating and dehydration.* To the extent that gathered natural gas contains contaminants, such as water vapor, carbon dioxide and/or hydrogen sulfide, such natural gas is dehydrated to remove the saturated water and treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.
- *Processing.* Natural gas has a widely varying composition depending on the field, formation reservoir or facility from which it is produced. Processing removes the heavier and more valuable hydrocarbon components, which are extracted as a mixed NGL stream that includes ethane, propane, butanes and natural gasoline (also referred to as "y-grade"). Processing aids in allowing the residue gas remaining after extraction of NGLs to meet the quality specifications for long-haul pipeline transportation and commercial use.
- *Fractionation.* Fractionation is the separation of the mixture of extracted NGLs into individual components for end-use sale. It is accomplished by controlling the temperature and pressure of the stream of mixed NGLs in order to take advantage of the different boiling points and vapor pressures of separate products. Fractionation systems typically exist either as an integral part of a gas processing plant or as a central fractionator, often located many miles from the primary production and processing complex. A central fractionator may receive mixed streams of NGLs from many processing plants. A fractionator can fractionate one product or in a central fractionator, multiple products. We operate fractionation facilities at certain processing facilities that separate ethane from the remainder of the y-grade stream. We also operate central fractionation facilities that separate y-grade into propane, butanes and natural gasoline.
- *Storage, transportation and marketing.* Once the raw natural gas has been treated or processed and the raw NGL mix has been fractionated into individual NGL components, the natural gas is delivered to

downstream transmission pipelines and NGL components are stored, transported and marketed to end-use markets. We market NGLs domestically as well as for export to international markets. NGLs are transported via pipeline, railcar, including unit trains, and truck. Each pipeline system typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily operational or supply-demand shifts. We have caverns for propane storage in the northeastern United States.

Historically, the majority of the domestic on-shore natural gas supply has been produced from conventional reservoirs that are characterized by large pockets of natural gas that are accessed using vertical drilling techniques. In the past decade, the supply of natural gas production from the conventional sources has declined as these reservoirs are being depleted. Due to advances in well completion technology and horizontal drilling techniques, unconventional sources, such as shale and tight sand formations, have become the most significant source of current and expected future natural gas production. The industry as a whole is characterized by regional competition, based on the proximity of gathering systems and processing/fractionation plants to producing natural gas wells, or to facilities that produce natural gas as a byproduct of refining crude oil. Due to the shift in the source of natural gas production, midstream providers with a significant presence in the shale plays will likely have a competitive advantage. Well-positioned operations allow access to all major NGL markets and provide for the development of export solutions for producers. This proximity is enhanced by infrastructure build-out and pipeline projects.

Basic NGL products and their typical uses are discussed below. The following basic NGL products are sold in our G&P segment.

- *Ethane* is used primarily as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products.
- *Propane* is used for heating, engine and industrial fuels, agricultural burning and drying and as a petrochemical feedstock for the production of ethylene and propylene.
- *Normal butane* is mainly used for gasoline blending, as a fuel gas, either alone or in a mixture with propane, and as a feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber.
- *Isobutane* is primarily used by refiners to enhance the octane content of motor gasoline.
- *Natural gasoline* is principally used as a motor gasoline blend stock or petrochemical feedstock.

The other primary products also produced and sold in our G&P segment are discussed below.

- *Ethylene* is primarily used in the production of a wide range of plastics and other chemical products.
- *Propylene* is primarily used in manufacturing plastics, synthetic fibers and foams. It is also used in the manufacture of polypropylene, which has a variety of end-uses including packaging film, carpet and upholstery fibers and plastic parts for appliances, automobiles, housewares and medical products.

OUR OPERATING SEGMENTS

We conduct our operations in the following operating segments: L&S and G&P. Our assets and operations in each of these segments are described below.

L&S:

The L&S segment includes transportation and storage of crude oil, refined products and other hydrocarbon-based products, primarily in the Midwest and Gulf Coast regions of the United States. These assets consist of a network of common carrier crude oil and refined product pipeline systems and associated storage assets and an inland marine business. We believe our network of petroleum pipelines is one of the largest in the United States, based on total annual volumes delivered. We also own a butane cavern in Neal, West Virginia with approximately 1,000 mbbls of liquefied petroleum gas storage capacity. Our marine business owns and operates boats, barges, and third-party chartered equipment and includes a Marine Repair Facility ("MRF"), which is a full service marine shipyard located on the Ohio River adjacent to MPC's Catlettsburg, Kentucky refinery. We have completed the Cornerstone pipeline project, which is the building block for other projects that we expect to become a critical solution for the industry to move condensate and NGLs out of the Marcellus and Utica regions into refining centers in the Midwest and connect to the pipelines to Canada. We are also constructing a butane cavern in Robinson, Illinois, which will be a 1,400-mbbl hard rock mined storage cavern. Our L&S assets are integral to the success of MPC's operations.

We generate revenue in the L&S segment primarily by charging tariffs for transporting crude oil, refined products and other hydrocarbon-based products through our pipelines and at our barge dock and fees for storing crude oil and refined products at our storage facilities. Our marine business generates revenue under a fee-for-capacity contract with MPC. We are also the operator of additional crude oil and refined product pipelines owned by MPC and third parties for which we are paid operating fees. For the year ended December 31, 2016, approximately 92 percent of L&S segment revenue and other income was generated from MPC. In this segment, we do not take ownership of the crude oil or products that we transport and store for our customers, and we do not engage in the trading of any commodities. However, we could be required to purchase or sell crude oil volumes in the open market to make up negative or positive imbalances.

The following is a summary of the significant assets owned by the L&S segment:

Crude Oil Pipeline System Name	Capacity (mbpd)	Associated MPC refineries
Patoka to Lima crude system	267	Detroit, MI; Canton, OH
Catlettsburg and Robinson crude system	515	Robinson, IL; Catlettsburg, KY
Detroit crude system	197	Detroit, MI
Wood River to Patoka crude system	314	All Midwest refineries
Total crude oil pipelines	1,293	

Product Pipeline System Name	Capacity (mbpd)	Associated MPC refineries
Cornerstone products system	238	Canton, OH
Garyville products system	389	Garyville, LA
Texas City products system	215	Texas City, TX; Galveston Bay, TX
ORPL products system	244	Catlettsburg, KY; Canton, OH
Robinson products system	513	Robinson, IL
Louisville airport products system	29	Robinson, IL
Total product pipelines	1,628	

Other L&S Assets	Capacity(1)	Associated MPC refineries
Wood River barge dock	78 mbpd	Garyville, LA
Neal butane cavern	1,000 mbbls	Catlettsburg, KY
Tank farms	4,533 mbbls	All Midwest refineries
Marine Repair Facility	N/A	Catlettsburg, KY

(1) All capacity shown is for 100 percent of the available storage capacity of our butane cavern and tank farms and 100 percent of the barge dock's average capacity.

As of December 31, 2016, our marine transportation operations included 18 owned towboats as well as 204 owned and 18 leased barges that transport refined products and crude oil on the Ohio, Mississippi and Illinois rivers and their tributaries and inter-coastal waterways. The following table sets forth additional details about MPLX LP's barges and towboats.

Marine Vessels	Number at December 31, 2016	Capacity (thousand barrels)	Associated MPC refineries
Inland tank barges:[1]			Catlettsburg, KY; Garyville, LA
Less than 25,000 barrels	64	963	
25,000 barrels and over	158	4,631	
Total	222	5,594	
Inland towboats:			Catlettsburg, KY; Garyville, LA
Less than 2,000 horsepower	2		
2,000 horsepower and over	16		
Total	18		

(1) All of our barges are double-hulled.

G&P:

Natural Gas Gathering

We operate several natural gas gathering systems that have a combined 5,439 mmcf/d throughput capacity in six states. The scope of gathering services that we provide depends on the composition of the raw, or untreated, gas at our producer customers' wellheads. For dry gas, we gather and, if necessary, treat the gas and deliver it to downstream transmission systems. For wet gas that contains heavier and more valuable hydrocarbons, we gather the gas for processing at a processing complex. The capacities of these gathering systems are supported by long-term fee-based agreements with major producer customers.

Natural Gas Processing

Our natural gas processing complexes remove the heavier and more valuable hydrocarbon components from natural gas. This allows the residue gas remaining after extraction of the NGLs to meet the quality specifications for long-haul transmission pipeline transportation or commercial use.

We currently operate five complexes in the Marcellus Shale, including: processing, gathering, and C2+ fractionation at the Houston Complex located in Washington County, Pennsylvania (the "Houston Complex"); processing and de-ethanization at the Majorsville Complex located in Marshall County, West Virginia (the "Majorsville Complex"); processing and de-ethanization at the Mobley Complex located in Wetzel County, West Virginia (the "Mobley Complex"); processing and de-ethanization at the Sherwood Complex located in Doddridge County, West Virginia (the "Sherwood Complex"); and processing, gathering, and C2+ fractionation at the Keystone Complex located in Butler County, Pennsylvania (the "Keystone Complex"). Further, we operate one condensate stabilization facility with two mbpd of capacity near the Houston Complex.

MarkWest Utica EMG, our joint venture with an affiliate of EMG, operates two complexes in the Utica Shale, including: processing and de-ethanization at the Cadiz Complex in Harrison County, Ohio (the "Cadiz Complex") and processing at the Seneca Complex in Noble County, Ohio (the "Seneca Complex"). We also operate a C3+ fractionation complex at the Hopedale Complex located in Harrison County, Ohio (the "Hopedale Complex"). Ohio Condensate, our joint venture with Summit, operates one condensate stabilization facility with 23 mbpd of capacity.

We operate four processing complexes in the Appalachia region, including: the Kenova Complex located in Wayne County, West Virginia (the “Kenova Complex”); the Boldman Complex located in Pike County, Kentucky (the “Boldman Complex”); the Cobb Complex located in Kanawha County, West Virginia (the “Cobb Complex”); and the Langley Complex located in Langley, Kentucky (the “Langley Complex”). Further, we operate a C3+ fractionation complex at the Siloam Complex in South Shore, Kentucky (the “Siloam Complex”).

We also operate four complexes in the Southwest region, including: processing and gathering at the Carthage Complex located in Panola County, Texas (the “Carthage Complex”); processing and gathering at the Western Oklahoma Complex located in Custer and Beckham Counties, Oklahoma (the “Western Oklahoma Complex”); processing at the Hidalgo Complex located in Culberson County, Texas (the “Hidalgo Complex”); and treating, processing and C2+ fractionation at the Javelina Complex located in Corpus Christi, Texas (the “Javelina Complex”). We also own a non-operating interest in the Centrahoma processing complex.

The following table summarizes our current and planned processing assets:

Plant	Existing capacity (mmcf/d)	Expansion capacity under construction (mmcf/d)	Expected in-service of expansion capacity	Geographic Region
Keystone Complex	410	—	N/A	Marcellus Operations
Harmon Creek Complex	—	200	2018	Marcellus Operations
Houston Complex[1]	555	200	Q1 2018	Marcellus Operations
Majorsville Complex[1]	1,070	200	2018	Marcellus Operations
Mobley Complex	920	—	N/A	Marcellus Operations
Sherwood Complex	1,200	600	Q2 2017, Q4 2017 and Q1 2018	Marcellus Operations
Cadiz Complex[2]	525	200	2018	Utica Operations
Seneca Complex[2]	800	—	N/A	Utica Operations
Kenova Complex	160	—	N/A	Southern Appalachian Operations
Boldman Complex	70	—	N/A	Southern Appalachian Operations
Cobb Complex	65	—	N/A	Southern Appalachian Operations
Langley Complex	325	—	N/A	Southern Appalachian Operations
Carthage Complex	600	—	N/A	Southwest Operations
Western Oklahoma Complex	425	—	N/A	Southwest Operations
Hidalgo Complex	200	—	N/A	Southwest Operations
Javelina Complex	142	—	N/A	Southwest Operations
Total	7,467	1,400		

(1) We have the operational flexibility to process gas for producer customers at either complex.

(2) We have the operational flexibility to process gas for producer customers at either complex.

The following table summarizes our key producer customers and attributes for each geographic region as of December 31, 2016:

	Marcellus Operations	Utica Operations	Southern Appalachian Operations	Southwest Operations
Key Producer Customers	Range Resources, Antero(1), EQT(1), CNX, Noble(1), Southwestern(1), Rex and others	Antero(1), Gulfport, Ascent, Rice, Rex, PDC and others	Chesapeake(1)(2), EQT(1) and NiSource(1)	Anadarko, Newfield, BP, PetroQuest and others
Volume Protection	65% of 2016 capacity contains minimum volume commitments	27% of 2016 capacity contains minimum volume commitments	24% of 2016 capacity contains minimum volume commitments	15% of 2016 capacity contains minimum volume commitments
Area Dedications	4 million acres	3.9 million acres	None	1.5 million acres

(1) We do not provide gathering services for these producer customers.

(2) In the fourth quarter of 2016, Chesapeake executed a purchase and sale agreement to sell the majority of its upstream and midstream assets in the Devonian Shale located in West Virginia and Kentucky. The new owner continues to utilize our processing facilities in the Southern Appalachian Operations.

NGL Gathering

Once natural gas has been processed at a natural gas processing complex, the heavier and more valuable hydrocarbon components, which have been extracted as a mixed NGL stream, can be further separated into their component parts through the process of fractionation. We operate several NGL gathering pipelines for these mixed NGL streams that have a combined 818 mbpd throughput capacity in five states.

C3+ NGL Fractionation Complexes

Our NGL fractionation facilities separate the mixture of extracted NGLs into individual purity product components for end-use sale. All NGLs, other than purity ethane as discussed below, produced at our Majorsville Complex, Mobley Complex and Sherwood Complex are gathered to the Houston Complex or to the Hopedale Complex through a system of NGL pipelines to allow for fractionation into purity NGL products. We can also gather NGLs produced at a third-party’s processing facilities to the Houston, Hopedale and Keystone Complexes for fractionation.

Our fractionation facilities for propane and heavier NGLs are supported by long-term, fee-based agreements with our key producer customers. The following tables summarize our current and planned fractionation assets at these facilities:

Facility	Existing propane and heavier NGLs + capacity (mbpd)	Market outlets	Geographic Region
Keystone Complex	47	Railcar and truck loading	Marcellus Operations
Hopedale Complex[1]	180	Key interstate pipeline access Railcar and truck loading Marine vessels	Marcellus and Utica Operations
Houston Complex	60	Key interstate pipeline access Railcar and truck loading Marine vessels	Marcellus Operations
Siloam Complex	24	Railcar and truck loading Marine vessels	Southern Appalachian Operations
Javelina Complex	11	Key interstate pipeline access	Southwest Operations
Total	322		

(1) The Hopedale Complex is jointly owned by MarkWest Ohio Fractionation Company, L.L.C. ("Ohio Fractionation") and MarkWest Utica EMG. Ohio Fractionation is a subsidiary of MarkWest Liberty Midstream & Resources, L.L.C ("MarkWest Liberty Midstream"). MarkWest Liberty Midstream and MarkWest Utica EMG are entities that operate in the Marcellus and Utica regions, respectively. We account for MarkWest Utica EMG as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.

Ethane Recovery, Transportation and Associated Market Outlets

As a result of the volume of natural gas production from the liquids-rich areas of the Marcellus and Utica Shales, we have begun recovering ethane from the natural gas stream for producer customers, which allows them to meet residue gas pipeline quality specifications and downstream pipeline commitments. Depending on market conditions, producer customers may also benefit from the potential price uplift received from the sale of their ethane. The following table summarizes our current and planned de-ethanization assets, which are, or are expected to be, supported by a network of purity ethane pipelines:

Facility	Existing ethane capacity (mbpd)	Ethane expansion capacity under construction (mbpd)	Expected in-service of expansion capacity	Geographic Region
Keystone Complex	14	20	Q3 2017	Marcellus Operations
Harmon Creek Complex	—	20	2018	Marcellus Operations
Houston Complex	40	—	N/A	Marcellus Operations
Majorsville Complex	40	40	Q4 2017	Marcellus Operations
Mobley Complex	10	—	N/A	Marcellus Operations
Sherwood Complex	40	—	N/A	Marcellus Operations
Cadiz Complex	40	—	N/A	Utica Operations
Javelina Complex	18	—	N/A	Southwest Operations
Total	202	80		

We have connections to several downstream ethane pipeline projects from many of our systems as follows:

- We transport purity ethane produced at the Majorsville Complex and the Sherwood Complex to the Houston Complex on a FERC pipeline. Beginning in April 2016, purity ethane produced at the Mobley Complex began being transported on this same FERC pipeline to the Houston Complex.
- We deliver purity ethane to Sunoco Logistics Partners L.P.'s ("Sunoco") Mariner West pipeline ("Mariner West") from the Houston Complex and from the Keystone Complex.
- We deliver purity ethane to Enterprise Products Partners L.P.'s Appalachia-to-Texas Express ("ATEX") pipeline from the Houston Complex and the Cadiz Complex.
- Sunoco developed the Mariner East project ("Mariner East"), a pipeline and marine project that originates at our Houston Complex. Beginning in December 2014, Mariner East began transporting propane to Sunoco's terminal near Philadelphia, Pennsylvania ("Marcus Hook Facility") where it is loaded onto marine vessels and delivered to international markets. Beginning in May 2016, Mariner East began transporting purity ethane in addition to propane to the Marcus Hook Facility.
- Sunoco has announced phase two of Mariner East ("Mariner East II") with plans to construct a pipeline from our Houston and Hopedale Complexes in western Pennsylvania and eastern Ohio, respectively, to transport propane and butane to the Marcus Hook Facility where it will be loaded onto marine vessels and delivered to domestic and international markets. The Mariner East II pipeline is expected to be operational in late 2017.

A significant portion of our business comes from a limited number of key customers. For the year ended December 31, 2016, revenues earned from one customer are significant to the segment, accounting for 17 percent of G&P segment revenue and 12 percent of consolidated revenue and other income. Additionally, revenues earned from a second customer are significant to the segment, accounting for 15 percent of G&P segment revenue and 10 percent of consolidated revenue and other income.

For further financial information regarding our segments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data included in this Annual Report on Form 10-K.

Equity Investment in Unconsolidated Affiliates—MarkWest Utica EMG

MarkWest Utica EMG is engaged in providing natural gas gathering, processing, and NGL fractionation, transportation and marketing services in the Utica Shale in eastern Ohio. We own 56 percent of MarkWest Utica EMG as of December 31, 2016.

The financial results for MarkWest Utica EMG and other unconsolidated affiliates are included in *(Loss) income from equity method investments* in our Consolidated Statements of Income. For a complete discussion of the formation of, and the accounting treatment for, MarkWest Utica EMG and other material unconsolidated affiliates, see Item 8. Financial Statements and Supplementary Data—Note 5.

OUR TRANSPORTATION AND STORAGE SERVICES AGREEMENTS WITH MPC

Our L&S assets are strategically located within, and integral to, MPC's operations. We have entered into multiple transportation and storage services agreements with MPC. Under these long-term, fee-based agreements, we provide transportation and storage services to MPC and, other than on our marine transportation service agreement, MPC has committed to provide us with minimum quarterly throughput volumes on crude oil and refined products pipelines systems and minimum storage volumes of crude oil, products and butane. MPC has also committed to provide a fixed fee for 100 percent of available capacity for boats, barges and third-party chartered equipment under the marine transportation service agreement. All of our transportation services agreements for our crude oil and refined products pipeline systems include a 5-15 year term with various automatic renewal terms ranging from multiple 2-5 year terms unless terminated by either party no later than six months prior to the end of the term. Our butane cavern storage services agreement includes a 10-year term but does not automatically renew. Our storage services agreements for our tank farms include a three-year term and automatically renew for additional one-year terms unless terminated by either party no later than six months prior to the end of the term. Our marine transportation service agreement includes an initial six-year term and automatically renews up to two additional five-year terms unless terminated by either party no later than twelve months prior to the end of the current term.

The following table sets forth additional information regarding our transportation and storage services agreements:

Transportation and Storage Services Agreements with MPC

Agreement	Initiation Date	Term (years)	MPC minimum commitment[1]
Transportation Services (mbpd):			
Crude systems	October 31, 2012	5-10	745
Product systems	Various	10-15	900
Marine	January 1, 2015	6	N/A[2]
Storage Services (mbbls):			
Neal Butane Cavern	October 31, 2012	10	1,000
Tank Farms	Various	3	4,963

(1) Quarterly commitment for our transportation services agreements in thousands of barrels per day and committed storage for our storage services agreements in thousands of barrels. Volumes shown for crude oil transportation services agreements are adjusted for crude viscosities.
(2) MPC has committed to utilize 100 percent of our available capacity of tanks and barges.

Under all of our transportation services agreements, except for our marine agreement, if MPC fails to transport its minimum throughput volumes during any quarter, then MPC will pay us a deficiency payment equal to the volume of the deficiency multiplied by the tariff rate then in effect (the "Quarterly Deficiency Payment"). Under these transportation services agreements, the amount of any Quarterly Deficiency Payment paid by MPC may be applied as a credit for any volumes transported on the applicable pipeline system in excess of MPC's minimum volume commitment during any of the succeeding four or eight quarters, after which time any unused credits will expire. Upon the expiration or termination of a transportation services agreement, MPC will have the opportunity to apply any such remaining credit amounts until the completion of any such four-quarter or eight-quarter period, as applicable. Any such remaining credits may be used against any volumes shipped by MPC on the applicable pipeline system, without regard to any minimum volume commitment that may have been in place during the term of the agreement.

MPC's obligations under these transportation and storage services agreements will not terminate if MPC no longer controls our general partner.

OPERATING AND MANAGEMENT SERVICES AGREEMENTS WITH MPC AND THIRD PARTIES

Operating Agreements

Through MPL, we operate various pipeline systems owned by MPC and third parties under existing operating services agreements that MPL has entered into with MPC and third parties. Under these operating services agreements, MPL receives an operating fee for operating the assets, which include certain MPC wholly-owned or partially-owned crude oil and refined product pipelines, and for providing various operational services with respect to those assets. MPL is generally reimbursed for all direct and indirect costs associated with operating the assets and providing such operational services. These agreements generally range from one to five years in length and automatically renew. Most of the agreements are indexed for inflation.

As noted above, MPL receives an annual fee for operating certain pipeline systems owned by MPC. This fee is currently $16 million and will be adjusted annually for inflation. MPC has agreed to indemnify MPL against any and all damages arising out of the operation of MPC's pipeline systems unless such occurrence is due to the gross negligence or willful misconduct of MPL. MPL has agreed to indemnify MPC against any and all damages arising out of MPL's gross negligence or willful misconduct in the operation of the pipeline systems. The initial term of this agreement was for one year and automatically renews from year-to-year unless terminated by either party.

Our existing operating services agreements include an operating agreement with Red Butte Pipe Line Company, which is owned by a third party. Under this agreement, MPL receives an operating fee for operating certain pipelines in Wyoming and Montana. The term of this agreement is through December 2018.

MPL maintains and operates four undivided joint interest pipeline systems including Capline, Centennial, Lou-Lex and Muskegon. MPL receives an operating fee for each of these systems, which is subject to adjustment for inflation. In addition, we are reimbursed for specific costs associated with operating each pipeline system. The length and renewals terms for each agreement vary.

Management Services Agreements

The Partnership has two management services agreements with wholly-owned subsidiaries of MPC under which it provides certain management services to MPC with respect to certain of MPC's retained pipeline assets. The Partnership received $1 million in fees under these agreements in 2016. The Partnership may adjust annually for inflation and based on changes in the scope of management services provided.

The Partnership also receives engineering and construction and administrative management fee revenue and other direct personnel costs for operating some joint venture entities.

The Partnership, through its wholly-owned subsidiary, HSM, has a management services agreement with MPC under which HSM provides management services to assist MPC in the oversight and management of the marine business. HSM receives a fixed annual fee for providing the required management services. This fee is adjusted annually on the anniversary of the contract for inflation and any changes in the scope of the management services provided. The Partnership received $21 million in fees under this agreement in 2016. This agreement expires on June 30, 2020.

OTHER AGREEMENTS WITH MPC

We have the following additional agreements with MPC:

- *Omnibus Agreement.* As of October 31, 2012, we entered into an omnibus agreement with MPC that addresses our payment of a fixed annual fee to MPC for the provision of executive management services by certain executive officers of our general partner and our reimbursement to MPC for the provision of certain general and administrative services to us, as well as MPC's indemnification of us for certain matters, including certain environmental, title and tax matters. In addition, we will indemnify MPC for certain matters under this agreement.

- *Employee Services Agreements.* We have four employee services agreements with MPC. Two of the employee services agreements with MPC were entered into effective October 1, 2012, under which we agreed to reimburse MPC for the provision of certain operational and management services to us in support of our pipelines, barge dock, butane cavern and tank farms within the L&S segment. Effective December 28, 2015, we entered into an additional employee services agreement with MPC, which requires that we reimburse MPC for certain operational and management services to us in support of our G&P segment and certain of our other operations. Lastly, we are party to an employee services agreement dated January 1, 2015, pursuant to which HSM reimburses MPC for employee benefit expenses along with certain operation and management services provided in support of HSM's areas of operation. The agreement is effective until December 31, 2019. Prior to January 1, 2015, this agreement did not exist.

OUR RELATIONSHIP WITH MPC

One of our competitive strengths is our strategic relationship with MPC, which we believe to be the largest crude oil refiner in the Midwest and the third-largest in the United States based on crude oil refining capacity. MPC owns and operates seven refineries and associated midstream transportation and logistics assets in PADD II and PADD III, which consist of states in the Midwest and Gulf Coast regions of the United States, along with an extensive wholesale and retail refined product marketing operation that serves markets primarily in the Midwest, Gulf Coast and Southeast regions of the United States. MPC markets refined products under the Marathon brand through an extensive network of retail locations owned by independent entrepreneurs, and under the Speedway brand through its wholly-owned subsidiary, Speedway LLC, which operates what we believe to be the nation's second largest chain of company-owned and operated retail gasoline and convenience stores. In addition, MPC sells refined products in the wholesale markets. MPC had consolidated revenues of approximately $63 billion in 2016. Marathon Petroleum Corporation's common stock trades on the NYSE under the symbol "MPC."

MPC's operations necessitate large-scale movements of crude oil and feedstocks to and among its refineries, as well as large-scale movements of refined products from its refineries to various markets. To this end, MPC has an extensive portfolio of midstream assets that can potentially be sold and/or contributed to us, providing us with a competitive advantage. As of December 31, 2016, these midstream assets included investments in crude oil and refined product pipelines, an ocean vessel joint venture, light product and asphalt terminals, a fuels distribution business and certain refinery assets.

MPC retains a significant interest in us through its ownership of our general partner, an approximate 23.5 percent limited partner interest (including the Class B units on an as-converted basis) in us and all of our incentive distribution rights as of February 13, 2017. We believe MPC will promote and support the successful execution of our business strategies given its significant interest in us and its stated intention to use us to grow its midstream business. This includes an expectation for MPC to offer us assets contributing an estimated $1.4 billion of annual EBITDA by the end of 2017, subject to market and other conditions. The transactions are expected to support increased limited and general partner distributions and provide value creation for investors.

We also may pursue acquisitions cooperatively with MPC which has the balance sheet flexibility and the ability to incubate projects for us to purchase later. However, MPC is under no obligation to offer to sell us additional assets or to pursue acquisitions cooperatively with us, and we are under no obligation to buy any such additional assets or pursue any such cooperative acquisitions.

OUR G&P CONTRACTS WITH THIRD PARTIES

We generate the majority of our revenues in the G&P segment from natural gas gathering, transportation and processing; NGL gathering, transportation, fractionation, marketing and storage; and crude oil gathering and transportation. We enter into a variety of contract types. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described below. We provide services under the following types of arrangements:

- *Fee-based arrangements*—Under fee-based arrangements, we receive a fee or fees for one or more of the following services: transportation and storage of crude oil; gathering, processing and transmission of natural gas; gathering, transportation, fractionation and storage of NGLs; and gathering and transportation of crude oil. The revenue we earn from these arrangements is generally directly related to the volume of natural gas, NGLs or crude oil that flows through our systems and facilities and is not normally directly dependent on commodity prices. In certain cases, our arrangements provide for minimum annual payments or fixed demand charges. Fee-based arrangements are reported as *Service revenue* on the Consolidated Statements of Income. In certain instances when specifically stated in the contract terms, we purchase product after fee-based services have been provided. Costs to purchase such products are reported as *Purchased product costs* and revenue from the sale of such products is reported as *Product sales* and recognized on a gross basis as we are the principal in the transaction.
- *Percent-of-proceeds arrangements*—Under percent-of-proceeds arrangements, we gather and process natural gas on behalf of producers, sell the resulting residue gas, condensate and NGLs at market prices and remit to producers an agreed-upon percentage of the proceeds. In other cases, instead of remitting cash payments to the producer, we deliver an agreed-upon percentage of the residue gas and NGLs to the producer (take-in-kind arrangements) and sell the volumes we retain to third parties. Revenue from these arrangements is reported on a gross basis where we act as the principal, as we have physical inventory risk and do not earn a fixed dollar amount. The agreed-upon percentage paid to the producer is reported as *Purchased product costs* on the Consolidated Statements of Income. Revenue is recognized on a net basis when we act as an agent and earn a fixed dollar amount of physical product and do not have risk of loss of the gross amount of gas and/or NGLs. Percent-of-proceeds revenue is reported as *Product sales* on the Consolidated Statements of Income.
- *Keep-whole arrangements*—Under keep-whole arrangements, we gather natural gas from the producer, process the natural gas and sell the resulting condensate and NGLs to third parties at market prices. Because the extraction of the condensate and NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make cash payment to the producers equal to the energy content of this natural gas. Certain keep-whole arrangements also have provisions that require us to share a percentage of the keep-whole profits with the producers based on the oil to gas ratio or the NGL to gas ratio. Sales of NGLs under these arrangements are reported as *Product sales* on the Consolidated Statements of Income and are reported on a gross basis as we are the principal in the arrangement. Natural gas purchased to return to the producer and shared NGL profits are recorded as *Purchased product costs* in the Consolidated Statements of Income.
- *Percent-of-index arrangements*—Under percent-of-index arrangements, we purchase natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount. We then gather and deliver the natural gas to pipelines where we resell the natural gas at the index price or at a different percentage discount to the index price. Revenue generated from percent-of-index arrangements are reported as *Product sales* on the Consolidated Statements of Income and are recognized on a gross basis as we purchase and take title to the product prior to sale and are the principal in the transaction.

In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. When fees are charged (in addition to product received) under keep-whole arrangements, percent-of-proceeds arrangements or percent-of-index arrangements, we record such fees as *Service revenue* on the Consolidated Statements of Income. When commodities are obtained as a result of providing our services, *Product sales* is recorded at the time the commodity is sold. The terms of our contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements.

Amounts billed to customers for shipping and handling, including fuel costs, are included in *Product sales* on the Consolidated Statements of Income, except under contracts where we are acting as an agent. Shipping and handling costs associated with product sales are included in *Purchased product costs* on the Consolidated Statements of Income. Taxes collected from customers and remitted to the appropriate taxing authority are excluded from revenue. Cost of revenues and depreciation represent those expenses related to operating our various facilities and are necessary to provide both *Product sales* and *Service revenue*. Reimbursements for third-party charges, such as electricity, are recorded net in *Cost of revenues.*

The terms of our contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements. Our contract mix and, accordingly, our exposure to natural gas and NGL prices may change as a result of changes in producer preferences, our expansion in regions where some types of contracts are more common and other market factors, including current market and financial conditions which have increased the risk of volatility in oil, natural gas and NGL prices. Any change in mix may influence our long-term financial results.

The following table does not give effect to our active commodity risk management program. For further discussion of how we manage commodity price volatility for the portion of our net operating margin that is not fee-based, see Item 8. Financial Statements and Supplementary Data—Note 16. We manage our business by taking into account the partial offset of short natural gas positions primarily in the Southwest region of our G&P segment. The calculated percentages for net operating margin for percent-of-proceeds, percent-of-index and keep-whole contracts reflect the partial offset of our natural gas positions. The calculated percentages are less than one percent for percent-of-index due to the offset of our natural gas positions and, therefore, not meaningful to the table below. For the year ended December 31, 2016, we calculated the following approximate percentages of our net operating margin from the following types of contracts:

	Fee-Based	Percent-of-Proceeds(1)	Keep-Whole(2)
L&S(3)	100%	— %	— %
G&P(3)(4)	90%	9%	1%
Total	93%	6%	1%

(1) Includes condensate sales and other types of arrangements tied to NGL prices.
(2) Includes condensate sales and other types of arrangements tied to both NGL and natural gas prices.
(3) Detail on contract types above.
(4) Includes unconsolidated affiliates (See Item 8. Financial Statements and Supplementary Data—Note 5).

COMPETITION

Within our L&S segment, as a result of our contractual relationship with MPC under our transportation and storage services agreements, and our connections to MPC's refineries, we believe that our crude oil and refined product pipelines will not face significant competition for MPC's crude oil or products transportation requirements.

If MPC's customers reduced their purchases of products from MPC due to the increased availability of less expensive products from other suppliers or for other reasons, MPC may only ship the minimum volumes through our pipelines (or pay the shortfall payment if it does not ship the minimum volumes), which would cause a decrease in our revenues. MPC competes with integrated petroleum companies, which have their own crude oil supplies and distribution and marketing systems, as well as with independent refiners, many of which also have their own distribution and marketing systems. MPC also competes with other suppliers that purchase refined products for resale. Competition in any particular geographic area is affected significantly by the volume of products produced by refineries in that area and by the availability of products and the cost of transportation to that area from distant refineries.

In our G&P segment, we face competition for natural gas gathering and in obtaining natural gas supplies for our processing and related services; in obtaining unprocessed NGLs for gathering and fractionation; and in marketing our products and services. Competition for natural gas supplies is based primarily on the location of gas gathering systems and gas processing plants, operating efficiency and reliability and the ability to obtain a satisfactory price for products recovered. Competitive factors affecting our fractionation services include availability of capacity, proximity to supply and industry marketing centers and cost efficiency and reliability of service. Competition for customers to purchase our natural gas and NGLs is based primarily on price, delivery capabilities, flexibility and maintenance of high-quality customer relationships.

Our competitors include:

- natural gas midstream providers, of varying financial resources and experience, that gather, transport, process, fractionate, store and market natural gas and NGLs;
- major integrated oil companies and refineries;
- medium and large sized independent exploration and production companies;
- major interstate and intrastate pipelines; and
- other marine and land-based transporters of natural gas and NGLs.

Some of our competitors operate as MLPs and may enjoy a cost of capital comparable to and, in some cases, lower than ours. Other competitors, such as major oil and gas and pipeline companies, have capital resources and contracted supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas.

We believe that our customer focus, demonstrated by our ability to offer an integrated package of services and our flexibility in considering various types of contractual arrangements, allows us to compete more effectively. Additionally, we believe we have critical connections to a strong sponsor and the key market outlets for NGLs and natural gas. In the Marcellus and Utica regions, our early entrance in the liquids-rich corridors of the Marcellus and Utica shale plays through our strategic gathering and processing agreements with key producers enhances our competitive position to participate in the further development of these resource plays. In the Southern Appalachia region, our operational experience of more than 20 years as the largest processor and fractionator and our existing presence in the Appalachian Basin provide a significant competitive advantage. In the Southwest region, our major gathering systems are less than 15 years old, located primarily in the heart of shale plays with significant long-term growth opportunities and provide producers with low-pressure and fuel-efficient service, which differentiates us from many competing gathering systems in those areas. The strategic location of our assets, including those connected to MPC, and the long-term nature of many of our contracts also provide a significant competitive advantage.

INSURANCE

Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and business interruption. We are insured under MPC and other third-party insurance policies. The MPC policies are subject to shared deductibles.

SEASONALITY

The volume of crude oil and refined products transported on our pipeline systems, at our barge dock and stored at our storage assets is directly affected by the level of supply and demand for crude oil and refined products in the markets served directly or indirectly by our assets. Many effects of seasonality on the L&S segment's revenues will be mitigated through the use of our fee-based transportation and storage services agreements with MPC that include minimum volume commitments.

Our G&P segment can be affected by seasonal fluctuations in the demand for natural gas and NGLs and the related fluctuations in commodity prices caused by various factors such as changes in transportation and travel patterns and variations in weather patterns from year to year. However, we manage the seasonality impact through the execution of our marketing strategy. We have access to up to 50 million gallons of propane storage capacity in the Southern Appalachia region provided by an arrangement with a third party which provides us with flexibility to manage the seasonality impact. Overall, our exposure to the seasonal fluctuations in the commodity markets is declining due to our growth in fee-based business.

REGULATORY MATTERS

Our operations are subject to extensive regulations. The failure to comply with applicable laws and regulations or to obtain, maintain and comply with requisite permits and authorizations can result in substantial penalties and other costs to the Partnership. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. However, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Due to the myriad of complex federal, state, provincial and local regulations that may affect us, directly or indirectly, reliance on the following discussion of certain laws and regulations should not be considered an exhaustive review of all regulatory considerations affecting our operations.

Pipeline Control Operations. The majority of our pipeline systems are operated from central control rooms. These control centers operate with a SCADA (supervisory control and data acquisition) system equipped with computer systems designed to continuously monitor operational data. Monitored data includes pressures, temperatures, gravities, flow rates and alarm conditions. These systems include real-time transient leak detection system monitors throughput and alarms if pre-established operating parameters are exceeded. These control centers operate remote pumps, motors and valves associated with the receipt and delivery of products, and provide for the remote-controlled shutdown of pump stations on the pipeline systems. These systems also include fully functional back-up operations maintained and routinely operated throughout the year to ensure safe and reliable operations.

Common Carrier Liquids Pipeline Operations. Certain of our liquids pipeline systems are common carriers subject to regulation by various federal, state and local agencies. FERC regulates interstate transportation on liquids pipeline systems under the Interstate Commerce Act ("ICA"), Energy Policy Act of 1992 ("EPAct 1992") and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates for interstate service on these pipelines, including interstate pipelines that transport crude oil, natural gas liquids (including purity ethane) and refined petroleum products (collectively referred to as "petroleum pipelines"), be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. The ICA requires that interstate petroleum pipeline transportation rates and terms and conditions of service be filed with the governing agency, which is FERC, and publicly posted on the company's website. Under the ICA, interested persons may challenge new or changed rates or services. FERC is authorized to investigate such charges and may suspend the effectiveness of a newly filed rate or service for up to seven months. A successful protest to a new rate or service could result in a petroleum pipeline paying refunds, together with interest, for the period that the rate or service was in effect. A successful complaint to an existing rate or service could result in a petroleum pipeline paying reparations, together with interest, for the period beginning two years prior to the date of the complaint until the just and reasonable rate or service was established. FERC may also investigate, upon complaint or on its own motion, existing rates and related rules and may order a pipeline to change them prospectively.

EPAct 1992 deemed certain interstate petroleum pipeline rates then in effect to be just and reasonable under the ICA. These rates are commonly referred to as "grandfathered rates." Our rates in effect for the 365 day period ending on the date of the passage of EPAct 1992 for interstate transportation service were deemed just and reasonable and therefore are grandfathered. New rates have since been established after EPAct 1992 for certain pipeline systems, and the rates for certain of our products pipelines have subsequently been approved as market-based rates. FERC may change grandfathered rates upon complaint only after it is shown that a substantial change has occurred since enactment in either the economic circumstances or the nature of the services that were a basis for the rate.

EPAct 1992 required FERC to establish a simplified and generally applicable ratemaking methodology for interstate petroleum pipelines. As a result, FERC adopted an indexing rate methodology which, as currently in effect, allows petroleum pipelines to change their rates within prescribed ceiling levels that are tied to changes in the PPI. FERC's indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2011 and ending June 30, 2016, petroleum pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus 2.65 percent. During the five-year period commencing July 1, 2016, petroleum pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus 1.23 percent. The indexing methodology is applicable to existing rates, including grandfathered rates, with the exclusion of market-based rates and settlement rates (unless permitted under the settlement). A pipeline is not required to raise its rates up to the index ceiling, but it is permitted to do so and rate increases made under the index are presumed to be just and reasonable unless a protesting party can demonstrate that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. However, FERC is currently evaluating when and how indexed adjustments to rates can be challenged. Therefore, we cannot guarantee FERC will not make changes to its current policy regarding challenges in the future. Under the indexing rate methodology, in any year in which the index is negative, pipelines must file to lower their rates if those rates would otherwise be above the rate ceiling, unless the pipelines request and receive a waiver from FERC permitting them not to apply the negative index adjustment.

While petroleum pipelines often use the indexing methodology to change their rates, petroleum pipelines may elect to support proposed rates by using other methodologies such as cost-of-service ratemaking, market-based rates and settlement rates. A pipeline can follow a cost-of-service approach when seeking to increase its rates above the rate ceiling provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can charge market-based rates if it establishes that it lacks significant market power in the affected markets. In addition, a pipeline can establish rates under settlement if agreed upon by all current shippers. We have used index rates, settlement rates and market-based rates to change the rates for our different FERC regulated petroleum pipeline systems.

FERC issued a policy statement in May 2005 stating that it would permit interstate petroleum pipelines, among others, to include an income tax allowance in cost-of-service rates to reflect actual or potential tax liability attributable to a regulated entity's operating income, regardless of the form of ownership. Under FERC's policy, a tax pass-through entity seeking such an income tax allowance must establish that its partners or members have an actual or potential income tax liability on the regulated entity's income. Whether a pipeline's owners have such actual or potential income tax liability is subject to review by FERC on a case-by-case basis. Although this policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. Finally, FERC's income tax policy continues to be the subject of various appeals by shippers, before FERC and the courts. We cannot guarantee that FERC or the courts will not make changes to the policy in the future.

Intrastate services provided by certain of our liquids pipeline systems are subject to regulation by state regulatory authorities. Much of the state regulation is complaint-based, both as to rates and priority of access. The state regulators could limit our ability to increase our rates or to set rates based on our costs or could order us to reduce our rates and could require the payment of refunds to shippers.

FERC and state regulatory agencies generally have not investigated rates on their own initiative when those rates are not the subject of a protest or a complaint by a shipper. MPC has agreed not to contest our tariff rates for the term of our transportation and storage services agreements with MPC, but we do not have any these types of agreements with other third parties. FERC or a state commission could investigate our rates on its own initiative or at the urging of a third party if the third party is either a current shipper or is able to show that it has a substantial economic interest in our tariff rate level.

If our rate levels were investigated, the inquiry could result in a comparison of our rates to those charged by others or to an investigation of our costs, including:

- the overall cost of service, including operating costs and overhead;
- the allocation of overhead and other administrative and general expenses to the regulated entity;
- the appropriate capital structure to be utilized in calculating rates;
- the appropriate rate of return on equity and interest rates on debt;
- the rate base, including the proper starting rate base;
- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

If FERC or a state commission were to determine that our rates were or had become unjust and unreasonable, we could be ordered to reduce rates prospectively and pay refunds and/or reparations to shippers.

Because some of our pipelines are common carrier pipelines, we may be required to accept new shippers who wish to transport on our pipelines. It is possible that new shippers, current shippers or other interested parties may decide to challenge our tariff rates and/or the terms of service for our pipelines, including proration rules.

FERC-Regulated Natural Gas Pipelines. Our natural gas pipeline operations are subject to federal, state and local regulatory authorities. Specifically, we have FERC gas tariffs on file for MarkWest New Mexico, L.L.C. and MarkWest Pioneer with respect to our Hobbs Pipeline and the Arkoma Connector Pipeline. These pipelines are subject to regulation by FERC, and it is possible that we may have additional gas pipelines that may require such tariffs and may be subject to similar regulation in the future. FERC regulation of jurisdictional natural gas pipelines extends to various matters including:

- rates and rate structures;
- return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction, expansion, operation and disposition of assets;
- affiliate interactions; and
- to an extent, the level of competition in that regulated industry.

Under the Natural Gas Act ("NGA"), FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. As noted in the list above, FERC's authority to regulate those services includes the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services and various other matters. Natural gas companies may not charge rates that have been determined to be unjust and unreasonable, or unduly discriminatory by FERC. In addition, FERC prohibits FERC-regulated natural gas companies from unduly preferring, or unduly discriminating against, any person with respect to pipeline rates or terms and conditions of service or other matters. The rates and terms and conditions for the Hobbs Pipeline and the Arkoma Connector Pipeline can be found in their respective FERC-approved tariffs. Pursuant to FERC's jurisdiction, existing rates and/or other tariff provisions may be challenged (e.g., by complaint) and rate increases proposed by the pipeline or other tariff changes may be challenged (e.g., by protest). We also cannot be assured that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules, rights of access, capacity and other issues that impact natural gas facilities. Any successful complaint or protest related to our facilities could have an adverse impact on our revenues.

As noted above (under "Common Carrier Liquids Pipeline Operations"), FERC is reviewing its policies with respect to the inclusion of income tax allowances in cost-of-service rates. A Notice of Inquiry into these issues was issued by FERC on December 15, 2016. The outcome of this inquiry could affect the rates that interstate natural gas pipelines are permitted to charge.

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 ("2005 EPAct"). Under the 2005 EPAct, FERC may impose civil penalties of up to $1 million per day for each current violation of the NGA. The 2005 EPAct also amends the NGA to add an anti-market manipulation provision, which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC. FERC issued Order No. 670 to implement the anti-market manipulation provision of the 2005 EPAct. This order makes it unlawful for gas pipelines and storage companies that provide interstate services to: (i) directly or indirectly, use or employ any device, scheme or artifice to defraud in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's enforcement authority.

Standards of Conduct. FERC has adopted affiliate standards of conduct applicable to interstate natural gas pipelines and certain other regulated entities, defined as "Transmission Providers." Under these rules, a Transmission Provider becomes subject to the standards of conduct if it provides service to affiliates that engage in marketing functions (as defined in the standards). If a Transmission Provider is subject to the standards of conduct, the Transmission Provider's transmission function employees (including the transmission function employees of any of its affiliates) must function independently from the Transmission Provider's marketing function employees (including the marketing function employees of any of its affiliates). The Transmission Provider must also comply with certain posting and other requirements.

Market Transparency Rulemakings. In 2007, FERC issued Order 704, as amended and clarified in subsequent orders on rehearing, whereby wholesale buyers and sellers of more than 2.2 MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704.

Gas-Electric Coordination. In 2015, FERC issued Order 587-W and adopted new standards designed to improve coordination between the gas and electric industries. Among other things, the new standards revise the nomination timelines used by interstate natural gas pipelines. Interstate natural gas pipelines were required to implement the new standards in 2016. FERC continues to evaluate other measures to improve coordination between the gas and electric industries, and the adoption of any such measures may impact FERC's regulation of jurisdictional natural gas pipelines.

Intrastate Natural Gas Pipeline Regulation. Some of our intrastate gas pipeline facilities are subject to various state laws and regulations that affect the rates we charge and terms of service. Although state regulation is typically less onerous than FERC, state regulation typically requires pipelines to charge just and reasonable rates and to provide service on a non-discriminatory basis. The rates and service of an intrastate pipeline generally are subject to challenge by complaint. Additionally, FERC has adopted certain regulations and reporting requirements applicable to intrastate natural gas pipelines (and Hinshaw natural gas pipelines) that provide certain interstate services subject to FERC's jurisdiction. We could become subject to such regulations and reporting requirements in the future to the extent that any of our intrastate pipelines were to begin providing, or were found to provide, such interstate services.

Additional proposals and proceedings that might affect the natural gas industry periodically arise before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than other midstream natural gas companies with whom we compete.

Natural Gas Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC if the primary function of the facilities is gathering natural gas. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. We own a number of facilities that we believe establish the pipeline's status as a gatherer not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so we cannot provide assurance that FERC will not at some point assert that these facilities are within its jurisdiction or that such an assertion would not adversely affect our results of operations and revenues. In such a case, we would possibly be required to file a tariff with FERC, provide a cost justification for the transportation charge and obtain certificate(s) of public convenience and necessity for the FERC-regulated pipelines, and comply with additional FERC requirements.

In the states in which we operate, regulation of gathering facilities and intrastate pipeline facilities generally includes various safety, environmental and, in some circumstances, open access, non-discriminatory take requirement and complaint-based rate regulation. For example, some of our natural gas gathering facilities are subject to state ratable take and common purchaser statutes and regulations. Ratable take statutes and regulations generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes and regulations generally require gatherers to purchase gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. Although state regulation is typically less onerous than at FERC, these statutes and regulations have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or gather natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services or regulated as a public utility. Our gathering operations also may be or become subject to safety and operational regulations and permitting requirements relating to the design, siting, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Currently, PHMSA is evaluating possible changes to the scope and applicability of 49 C.F.R. Part 192, which governs construction standards and operation of natural gas gathering pipelines. The changes being considered include, but are not limited to, more stringent construction standards for remote facilities, as well as additional record-keeping requirements. Depending upon the nature of the final rule-making, those could have an impact upon MPLX LP operations.

Natural Gas Processing. Our natural gas processing operations are not presently subject to FERC or state rate regulation. There can be no assurance that our processing operations will continue to be exempt from FERC regulation in the future. In addition, although the processing facilities may not be directly related, other laws and regulations may affect the availability of natural gas for processing, such as state regulation of production rates and maximum daily production allowables from gas wells, which could impact our processing business.

NGL Pipelines. We have constructed various NGL product pipelines to transport NGL products, some of which are regulated by FERC, and we may elect to construct additional such pipelines in the future that may be subject to these same regulatory requirements. Pipelines providing transportation of NGLs in interstate commerce are subject to the same regulatory requirements as common carrier petroleum pipelines. See "Common Carrier Liquids Pipeline Operations" above. We have several NGL pipelines that carry NGLs owned by us between our processing and fractionation facilities that cross state lines. We do not have FERC tariffs on file for these pipelines because we believe they are not subject to FERC requirements or that they would otherwise meet the qualifications for a waiver from FERC's filing and reporting requirements. We cannot, however, provide assurance that FERC will not, at some point, either at the request of other entities or on its own initiative, assert that some or all of these pipelines are subject to FERC requirements for interstate petroleum pipelines and not exempt from its filing and reporting requirements. We also cannot provide assurance that such an assertion would not adversely affect our results of operations. In the event FERC were to determine that these NGL pipelines are subject to FERC requirements for common carrier pipelines or otherwise would not qualify for a waiver from FERC's applicable regulatory requirements, we would likely be required to file a tariff with FERC for the pipelines, provide a cost justification for their transportation rates, and provide service to all potential shippers without undue discrimination, and we may also be subject to fines, penalties or other sanctions. Our NGL pipelines are subject to safety regulation by the DOT under 49 C.F.R. Part 195 for operators of hazardous liquid pipelines. Currently, PHMSA is evaluating possible changes to the scope and applicability of 49 C.F.R. Part 195m, including, among other things, expansion of reporting obligations, additional inspection requirements, and expansion of the use of leak detection systems. Depending upon the nature of the final rule-making, those could have an impact upon MPLX LP operations. Our NGL pipelines and operations may also be or become subject to state public utility or related jurisdiction which could impose additional safety and operational regulations relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL gathering facilities.

Propane Regulation. National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states these laws are administered by state agencies and in others they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations cover the transportation of hazardous materials and are administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We maintain various permits that are necessary to operate our facilities, some of which may be material to our propane operations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in compliance in all material respects with applicable laws and regulations.

Marine Transportation. Our marine transportation business is subject to regulation by the USCG, federal laws, including the Jones Act, state laws and certain international conventions, as well as numerous environmental regulations. The majority of our vessels are subject to inspection by the USCG and carry certificates of inspection. The crews employed aboard the vessels are licensed or certified by the USCG. We are required by various governmental agencies to obtain licenses, certificates and permits for our vessels.

Our marine transportation business competes principally in markets subject to the Jones Act, a federal cabotage law that restricts domestic marine transportation in the United States to vessels built and registered in the United States, and manned and owned by United States citizens. We presently meet all of the requirements of the Jones Act for our vessels. The loss of Jones Act status could have a significant negative effect on us. The requirements that our vessels be United States built and manned by United States citizens, the crewing requirements and material requirements of the USCG, and the application of United States labor and tax laws increases the cost of

United States flag vessels when compared with comparable foreign flag vessels. Our marine transportation business could be adversely affected if the Jones Act were to be modified so as to permit foreign competition that is not subject to the same United States government imposed burdens. Since the events of September 11, 2001, the United States government has taken steps to increase security of United States ports, coastal waters and inland waterways. We believe that it is unlikely that the current cabotage provisions of the Jones Act would be modified or eliminated in the foreseeable future.

The Secretary of Homeland Security is vested with the authority and discretion to waive the Jones Act to such extent and upon such terms as the Secretary may prescribe whenever the Secretary deems that such action is necessary in the interest of national defense. In response to the effects of Hurricanes Katrina and Rita, the Secretary waived the Jones Act generally for the transportation of petroleum products from September 1 to September 19, 2005 and from September 26, 2005 to October 24, 2005. In June 2011, the Secretary waived the Jones Act for the transportation of petroleum released from the Strategic Petroleum Reserve and in November 2012 waived the Jones Act for the transportation of refined petroleum products in the Northeast following Hurricane Sandy. Waivers of the Jones Act, whether in response to natural disasters or otherwise, could result in increased competition from foreign tank vessel operators, which could negatively impact our marine transportation business.

Pipeline Interconnections. One or more of our plants include pipeline interconnections to, or incidental gathering pipelines (also known as "stub lines") that connect the plants to, interstate pipelines. These pipeline interconnections are an integral part of our facilities and are not currently being used, nor can they be used in the future, by any third party due to their origin points at our proprietary facilities. Therefore, we believe these pipeline interconnections are part of our plant facilities and are not subject to the jurisdiction of FERC. In the event that FERC were to determine that these pipeline interconnections were subject to its jurisdiction, we believe the pipelines would qualify for a waiver from most FERC reporting and filing requirements, including the obligation to file a FERC tariff. In the event that FERC were to determine that the pipeline interconnections did not qualify for such waivers, we would likely be required to file a tariff with FERC for the pipeline interconnections, provide a cost justification for their transportation rates and provide service to all potential shippers without undue discrimination. In such event, we may experience increased operating costs and reduced revenues.

Security. Certain of our facilities have been preliminarily classified as subject to the Department of Homeland Security Chemical Facility Anti-Terrorism Standards. In addition, we have several facilities that are subject to the United States Coast Guard's Maritime Transportation Security Act, and a number of other facilities that are subject to the Transportation Security Administration's Pipeline Security Guidelines and are designated as "Critical Facilities." The Transportation Security Administration Security Guidelines are subject to change without formal regulatory proposal and review. We have an internal inspection program designed to monitor and ensure compliance with all of these requirements. We believe that we are in material compliance with all applicable laws and regulations regarding the security of our facilities.

ENVIRONMENTAL REGULATION

General

Our processing and fractionation plants, storage facilities, pipelines and associated facilities are subject to multiple obligations and potential liabilities under a variety of federal, regional, state and local laws and regulations relating to environmental protection. Such environmental laws and regulations may affect many aspects of our present and future operations, including for example, requiring the acquisition of permits or other approvals to conduct regulated activities that may impose burdensome conditions or potentially cause delays, restricting the manner in which we handle or dispose of our wastes, limiting or prohibiting construction or other activities in environmentally sensitive areas such as wetlands or areas inhabited by endangered species, requiring us to incur capital costs to construct, maintain and/or upgrade processes, equipment and/or facilities, restricting the locations in which we may construct our compressor stations and other facilities and/or requiring the relocation of existing stations and facilities, and requiring remedial actions to mitigate any pollution that might be caused by our operations or attributable to former operations. Spills, releases or other incidents may occur in connection with our active operations or as a result of events outside of our reasonable control, which incidents may result in non-compliance with such laws and regulations. Any failure to comply with these legal requirements may expose us to the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of remedial or corrective actions and the issuance of orders enjoining or limiting some or all of our operations.

We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and the cost of continued compliance with such laws and regulations will not have a material adverse effect on our results of operations or financial condition. We cannot assure, however, that existing environmental laws and regulations will not be reinterpreted or revised or that new environmental laws and regulations will not be adopted or become applicable to us. For instance, the EPA is currently taking a closer look at pipeline maintenance operations, and the result of this closer review may yield modified emission calculations and/or regulations relating to such activities. Generally speaking, the trend in environmental law is to place more restrictions and limitations on activities that may be perceived to adversely affect the environment, which may cause significant delays in obtaining permitting approvals for our facilities, result in the denial of our permitting applications, or cause us to become involved in time consuming and costly litigation. Thus, there can be no assurance as to the amount or timing of future expenditures for compliance with environmental laws and regulations, permits and permitting requirements or remedial actions pursuant to such laws and regulations, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional environmental requirements may result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, and could have a material adverse effect on our business, financial condition, results of operations and cash flow. We may not be able to recover some or any of these costs from insurance. Such revised or additional environmental requirements may also result in substantially increased costs and material delays in the construction of new facilities or expansion of our existing facilities, which may materially impact our ability to meet our construction obligations with our producer customers.

Under the omnibus agreement, MPC has agreed to indemnify us for all known and certain unknown environmental liabilities that are associated with the ownership or operation of our assets that we acquired from MPC and due to occurrences on or before the closing of the Initial Offering. Indemnification for any unknown environmental liabilities will be limited to liabilities due to occurrences on or before the closing of the Initial Offering and identified prior to the fifth anniversary of the closing of the Initial Offering, and will be subject to an aggregate deductible of $500,000 before we are entitled to indemnification for losses incurred. Any other liabilities for which MPC has agreed to indemnify us are not subject to a deductible before we are entitled to indemnification. There is no limit on the amount for which MPC has agreed to indemnify us under the omnibus agreement once we meet the deductible, if applicable. Neither we nor our general partner have any contractual obligation to investigate or identify any such unknown environmental liabilities. We have agreed to indemnify MPC for events and conditions associated with the ownership or operation of our assets due to occurrences after the closing of the Initial Offering and for environmental liabilities associated with or arising from our ownership or operation of the assets on or after the closing of the Initial Offering, in each case, to the extent MPC is not required to indemnify us for such liabilities. Pipe Line Holdings has agreed to indemnify MPC for events and conditions associated with the operations of the Pipe Line Holdings assets that occur after the closing of the Initial Offering. Liabilities for which we and Pipe Line Holdings have agreed to indemnify MPC pursuant to the omnibus agreement are not subject to a deductible before MPC is entitled to indemnification. There is no limit on the amount for which we or Pipe Line Holdings has agreed to indemnify MPC under the omnibus agreement.

Hazardous Substances and Wastes

A comprehensive framework of environmental laws and regulations governs our operations as they relate to the possible release of hazardous substances or non-hazardous or hazardous wastes into soils, groundwater and surface water and measures taken to mitigate pollution into the environment. The Comprehensive Environmental

Response, Compensation, and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law, as well as comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include current and prior owners or operators of a site where a release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances released from the site. Under CERCLA, these persons may be subject to strict joint and several liability for the costs of removing or remediating hazardous substances that have been released into the environment and for restoration costs and damages to natural resources. Additionally, neighboring landowners and other third parties can file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. While we generate materials in the course of our operations that may be regulated as hazardous substances under CERCLA or similar state statutes, we do not believe that we have any current material liability for cleanup costs under such laws or for third-party claims. We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable or more stringent state statutes, which impose requirements relating to the handling and disposal of non-hazardous and hazardous wastes. In the course of our operations, we generate some amount of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes. While we are required to comply with RCRA requirements relating to hazardous wastes, currently our operations generate minimal quantities of such hazardous wastes. However, it is possible that some wastes generated by us that are currently classified as non-hazardous wastes may in the future be designated as hazardous wastes, resulting in the wastes being subject to more rigorous and costly transportation, storage, treatment and disposal requirements.

We currently own or lease, and have in the past owned or leased, properties that have been used over the years for natural gas gathering, processing and transportation, for NGL fractionation or for the storage, gathering and transportation of crude oil. Although waste disposal practices within the NGL industry and other oil and natural gas related industries have been enhanced and improved over the years, it is possible that petroleum hydrocarbons and other non-hazardous or hazardous wastes may have been disposed of by prior owners or operators on or under these various properties owned or leased by us during the operating history of those facilities. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination or to perform remedial operations to prevent future contamination. We do not believe that there presently exists significant surface and subsurface contamination of our properties by petroleum hydrocarbons or other wastes for which we are currently responsible.

Ongoing Remediation and Indemnification from Third Parties

The prior third-party owner or operator of our Cobb, Boldman, Kenova, Kermit and Majorsville facilities, has been, or is currently involved in, investigatory or remedial activities with respect to the real property underlying these facilities. These investigatory and remedial obligations arise out of a September 1994 "Administrative Order by Consent for Removal Actions" with EPA Regions II, III, IV and V; and with respect to the Boldman Complex, an "Agreed Order" entered into by the third-party owner/operator with the Kentucky Natural Resources and Environmental Protection Cabinet in October 1994. The third party or, in the case of the Kermit Complex, its successor in interest, has accepted sole liability and responsibility for, and indemnifies us against, any environmental liabilities associated with the EPA Administrative Order, the Kentucky Agreed Order or any other environmental condition related to the real property prior to the effective dates of our lease or purchase of the real property that are not contributed to by us. In addition, the third party, or in the case of the Kermit Complex, its successor in interest, has agreed to perform all the required response actions at its expense in a manner that minimizes interference with our use of the properties. We understand that to date, all actions required under these agreements have been or are being performed and, accordingly, we do not believe that the remediation obligation of these properties will have a material adverse impact on our financial condition or results of operations.

The prior third-party owner and/or operator of certain facilities on the real property on which our rail facility is constructed near Houston, Pennsylvania has been, or is currently involved in, investigatory or remedial activities related to acid mine drainage ("AMD") with respect to the real property underlying these facilities. These investigatory and remedial obligations arise out of an arrangement entered into between the Pennsylvania Department of Environmental Protection and the third party, which has accepted liability and responsibility for, and indemnifies us against, any environmental liabilities associated with the AMD that are not exacerbated by us in connection with our operations. In addition, the third party has agreed to perform all of the required response actions at its expense in a manner that minimizes interference with our use of the property. We understand that to date, all actions required under these agreements have been or are being performed and, accordingly, we do not believe that the remediation obligation of these properties will have a material adverse impact on our financial condition or results of operations.

We are also entitled to indemnification from MPC for assets we acquired from MPC in our Initial Offering, as further described above under "General". In addition, from time to time, we have acquired, and we may acquire in the future, facilities from third parties that previously have been or currently are the subject of investigatory, remedial or monitoring activities relating to environmental matters. The terms of each acquisition will vary, and in some cases we may receive contractual indemnification from the prior owner or operator for some or all of the liabilities relating to such matters, and in other cases we may agree to accept some or all of such liabilities. We do not believe that the portion of any such liabilities that the Partnership may bear with respect to any such properties previously acquired by the Partnership will have a material adverse impact on our financial condition or results of operations.

Water Discharges

Our operations can result in the discharge of pollutants, including crude oil and refined products. Regulations under the Water Pollution Control Act of 1972 ("Clean Water Act"), Oil Pollution Act of 1990 ("OPA-90") and analogous state laws impose restrictions and controls on the discharge of pollutants into federal and state waters. Such discharges are prohibited, except in accord with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law and some state laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a hydrocarbon tank spill, oil overflow, rupture or leak. For example, the Clean Water Act requires us to maintain Spill Prevention Control and Countermeasure ("SPCC") plans at many of our facilities. We maintain numerous discharge permits for facilities and vessels as required under the National Pollutant Discharge Elimination System program of the Clean Water Act and have implemented systems to oversee our compliance efforts. Any unpermitted release of pollutants, including oil, NGLs or condensates, could result in administrative, civil and criminal penalties as well as significant remedial obligations. In addition, the Clean Water Act and analogous state law may also require individual permits or coverage under general permits for discharges of storm water from certain types of facilities, but these requirements are subject to several exemptions specifically related to oil and natural gas operations and facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit. We conduct regular review of the applicable laws and regulations, and maintain discussions with the various federal, state and local agencies with regard to the application of those laws and regulations to our facilities, including the permitting process and categories of applicable permits for storm water or other discharges, stream crossings and wetland disturbances that may be required for the construction or operation of certain of our facilities in the various states. In June 2015, the EPA and the United States Army Corps of Engineers finalized significant changes to the definition of the term "waters of the United States" ("WOTUS") used in numerous programs under the Clean Water Act. This final rulemaking is referred to as the "Clean Water Rule." The Clean Water Rule has been challenged in multiple federal courts by many states, trade groups, and other interested parties, and in October 2015, a United States Court of Appeals issued a nationwide stay of the Clean Water Rule. The Clean Water Rule, as written, expands permitting, planning and reporting obligations and may extend the timing to secure permits for pipeline and fixed asset construction and maintenance activities. The Clean Water Rule does contain new language intended to address concerns that the proposed rule included storm water conveyances and storage structures as WOTUS, and we continue to review how that new language will apply under specific circumstances. Court challenges of the Clean Water Rule will continue through 2017.

In addition, the transportation and storage of crude oil and refined products over and adjacent to water involves risk and subjects us to the provisions of OPA-90 and related state requirements. Among other requirements, OPA-90 requires the owner or operator of a tank vessel, a facility or a pipeline to maintain an emergency plan to respond to releases of oil or hazardous substances. Also, in case of any such release, OPA-90 requires the responsible company to pay resulting removal costs and damages. OPA-90 also provides for civil penalties and imposes criminal sanctions for violations of its provisions. We operate facilities at which releases of oil and hazardous substances could occur. We have implemented emergency oil response plans for all of our components and facilities covered by OPA-90 and we have established SPCC plans for facilities subject to Clean Water Act SPCC requirements.

Construction or maintenance of our plants, compressor stations, pipelines, barge dock and storage facilities may impact wetlands, which are also regulated under the Clean Water Act by the EPA, the United States Army Corps of Engineers and state water quality agencies. Regulatory requirements governing wetlands (including associated mitigation projects) may result in the delay of our projects while we obtain necessary permits and may increase the cost of new projects and maintenance activities. We believe that we are in substantial compliance with the Clean Water Act and analogous state laws. However, there is no assurance that we will not incur material increases in our operating costs or delays in the construction or expansion of our facilities because of future developments, the implementation of new laws and regulations, the reinterpretation of existing laws and regulations, or otherwise, including, for example, increased construction activities, potential inadvertent releases arising from pursuing borings for pipelines, and earth slips due to heavy rain and/or other cause.

Hydraulic Fracturing

We do not conduct hydraulic fracturing operations, but we do provide gathering, processing and fractionation services with respect to natural gas and NGLs produced by our producer customers as a result of such operations. Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, and issued in May 2014 its Advance Notice of Proposed Rulemaking to solicit input on the possible Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in March 2015, the Bureau of Land Management ("BLM") published its final rule setting new standards for hydraulic fracturing on onshore federal and Indian lands. The final rules have been challenged and, in June 2016, the United States District Court for Wyoming set aside these BLM rules, holding that the BLM lacked the statutory authority to regulate the hydraulic fracturing process. In addition, Congress has from time to time considered legislation to provide for additional regulation of hydraulic fracturing, and some states have adopted, and other states are considering adopting, laws and/or regulations that could impose more stringent permitting, disclosure and well construction requirements on natural gas drilling activities or prohibit hydraulic fracturing altogether, similar to the State of New York. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. In the event that new or more stringent federal, state or local legal restrictions relating to natural gas drilling activities or to the hydraulic fracturing process are adopted in areas where our producer customers operate, those customers could incur potentially significant added costs to comply with such hydraulic fracturing-related requirements and experience delays or curtailment in the pursuit of production or development activities, which could reduce demand for our gathering, transportation and processing services and/or our NGL fractionation services.

In addition, certain governmental reviews are underway that focus on potential environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Most notably, in December 2016, the EPA released its final assessment of the impacts of hydraulic fracturing on drinking water. These studies could spur initiatives to further regulate hydraulic fracturing that could delay or curtail production of natural gas, and thus reduce demand for our midstream services.

Air Emissions

The Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, including processing plants and compressor stations, and also impose various monitoring and reporting requirements. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements, utilize specific equipment or technologies to control emissions, or aggregate two or more of our facilities into one application for permitting purposes. We may be required to incur capital expenditures in the future for installation of air pollution control equipment and encounter construction or operational delays while applying for, or awaiting the review, processing and issuance of new or amended permits, and we may be required to modify certain of our operations which could increase our operating costs. For example, the EPA issued final regulations in October 2015 to revise the National Ambient Air Quality Standard for ozone to 70 parts per billion, or ppb, for both the eight-hour primary and secondary standards protective of public health and public welfare. These standards, which are currently again under review, could require states to implement new more stringent regulations, which could apply to our operations and those of our producer customers. Compliance with these or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business. Federal and state regulators and agencies are also currently taking a closer look at pipeline maintenance operations and any emissions and permits that may be related to such activities. The result of this closer review may yield modified emission calculations and/or regulations relating to such activities or potentially enforcement actions by the agencies for unaccounted for or unpermitted emissions. EPA has finalized revisions to regulations or interpretations of regulations regarding aggregation of facilities for permitting purposes and performance standards for methane emissions from new and modified oil and gas production and natural gas processing and transmission facilities, any of which could require additional capital expenditures, increase our operating costs or otherwise restrict our operations. Additionally, in 2015, EPA finalized regulations to revise existing refinery air emissions standards, which require additional controls, lower emission standards and require ambient air monitoring. These revised refinery standards affect MPC's refineries from which we receive significant revenues. MPC has been required in the past, and will be required in the future, to incur significant capital expenditures to comply with new legislative and regulatory requirements relating to its operations. To the extent these capital expenditures have a material effect on MPC, they could have a material effect on our business and results of operations. We have been in discussions with various state agencies in the areas in which we operate with respect to their guidance, policies, rules and regulations regarding the permitting process, source determination, categories of applicable permits and control technology that may be required for the construction or operation of certain of our facilities. We believe that our operations are in substantial compliance with applicable air permitting and control technology requirements.

Climate Change

As a consequence of an EPA administrative conclusion that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") into the ambient air endangers public health and welfare, the EPA adopted regulations establishing the Prevention of Significant Deterioration ("PSD") construction and Title V operating permit programs for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. In addition, the EPA is gathering information regarding existing facilities in various industries, including information collection requests ("ICRs") issued in December 2016 to various oil and gas production and midstream facilities, which may be used to support potential future regulation of GHGs. Although the EPA's PSD and Title V permit programs are limited to large stationary sources of criteria pollutant emissions, states may seek to adopt their own permitting programs under state laws that require permit reviews of large stationary sources emitting only GHGs. If we were to become subject to Title V and PSD permitting requirements due to non-GHG criteria pollutants, or if the EPA implemented more stringent permitting requirements relating to GHG emissions without regard to non-GHG criteria pollutants, or if states adopt their own permitting programs that require permit reviews based on GHG emissions, we may be required to install “best available control technology,” to the extent such technology is available, to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future. In addition, we may experience substantial delays or possible curtailment of construction or projects in connection with applying for, obtaining or maintaining preconstruction and operating permits, we may encounter limitations on the design capacities or size of facilities, and we may incur material increases in our construction and operating costs. The EPA has also adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas sources in the United States, including, among others, certain onshore and offshore oil and natural gas production and onshore oil and natural gas processing, fractionation, transmission, storage and distribution facilities, which includes certain of our operations. In addition, in 2015, the EPA issued rules expanding the petroleum and natural gas system sources for which annual GHG emissions reporting is required to include GHG emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. We are monitoring GHG emissions from certain of our facilities in accordance with current GHG emissions reporting requirements in a manner that we believe is in substantial compliance with applicable reporting obligations. Additionally, in 2015 the EPA finalized rules to limit GHG emissions from new and existing power plants, although the United States Supreme Court issued a stay of these rules in February 2016 while the rules are under review by the United States Court of Appeals for the District of Columbia Circuit. The requirements could increase the cost of electricity and natural gas for our operations and ultimately states could impose additional GHG emission reduction requirements. In sum, requiring reductions in GHG emissions at our facilities could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls at our facilities and (iii) administer and manage any GHG emissions programs, including acquiring emission credits or allotments. These requirements may also significantly affect MPC’s refinery operations and may have an indirect effect on our business, financial condition and results of operations.

Also, Congress has from time to time considered legislation to reduce emissions of GHGs, and while there has not been federal climate legislation adopted in the United States in recent years, it is possible that such legislation could be enacted in the future. In the absence of federal climate legislation in the United States, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress were to undertake comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for oil, natural gas, NGLs and products derived therefrom. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements including the imposition of a carbon tax. The EPA issued final rules in May 2016 aimed at minimizing fugitive emissions and establishing methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. This rule is currently being challenged in court by various affected states. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, oil and natural gas produced by our exploration and production customers that, in turn, could reduce the demand for our services and thus adversely affect our cash available for distribution to our unitholders.

Endangered Species Act and Migratory Bird Treaty Act Considerations

The federal Endangered Species Act ("ESA") and analogous laws regulate activities that may affect endangered or threatened species, including their habitats. If endangered species are located in areas where we propose to construct new gathering or transportation pipelines or processing or fractionation facilities, such work could be prohibited or delayed in certain of those locations or during certain times, when our operations could result in a taking of the species. We also may be obligated to develop plans to avoid potential takings of protected species, the implementation of which could materially increase our operating and capital costs. Existing laws, regulations, policies and guidance relating to protected species may also be revised or reinterpreted in a manner that further increase our construction and mitigation costs or restricts our construction activities. Additionally, construction and operational activities could result in inadvertent impact to a listed species and could result in alleged takings under the ESA, exposing the Partnership to civil or criminal enforcement actions and fines or penalties. Moreover, as a result of a settlement approved by the United States District Court for the District of Columbia in September 2011, the United States Fish and Wildlife Service ("FWS") is required to make a determination on listing numerous species as endangered or threatened under the ESA by completion of the agency's 2017 fiscal year. For example, in April 2015, the FWS published a final rule listing the Northern Long Eared Bat as threatened under the ESA. In another example, in March 2014, the FWS announced the listing of the lesser prairie chicken as a threatened species under the ESA. In addition, in January 2017, FWS announced that it will list the rusty patched bumblebee as an endangered species effective in February 2017. All of these species, along with the other endangered species such as the Indiana Bat and American Burying Beetle, are in areas in which we operate. The listing of these or other species as threatened or endangered in areas where we conduct operations or plan to construct pipelines or facilities may cause us to incur increased costs arising from species protection measures or could result in delays in, or prohibit, the construction of our facilities or limit our customer's exploration and production activities, which could have an adverse impact on demand for our midstream operations.

The Migratory Bird Treaty Act implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. In accordance with this law, the taking, killing or possessing of migratory birds covered under this act is unlawful without a permit. If there is the potential to adversely affect migratory birds as a result of our operations or construction activities, we may be required to obtain necessary permits to conduct those operations or construction activities, which may result in specified operating or construction restrictions on a temporary, seasonal, or permanent basis in affected areas and thus have an adverse impact on our ability to provide timely gathering, processing or fractionation services to our exploration and production customers.

Pipeline Safety Matters

Our assets are subject to increasingly strict safety laws and regulations. The transportation and storage of natural gas and crude oil and refined products involve a risk that hazardous liquids may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant government penalties, liability to government agencies for natural resources damages and significant business interruption. The DOT has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection and management of our pipeline assets. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

We are subject to regulation by the DOT under the Hazardous Liquid Pipeline Safety Act of 1979, also known as the HLPSA. The HLPSA delegated to the DOT the authority to develop, prescribe and enforce minimum federal safety standards for the transportation of hazardous liquids by pipeline. Congress also enacted the Pipeline Safety Act of 1992, also known as the PSA, which added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, required regulations be issued to define the term “gathering line” and establish safety standards for certain “regulated gathering lines,” and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in High Consequence Areas (“HCAs”), defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In 1996, Congress enacted the Accountable Pipeline Safety and Partnership Act, also known as the APSPA, which limited the operator identification requirement mandate to pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline rupture would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, also known as the PIPES Act, Congress required mandatory inspections for certain U.S. crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management. We are also subject to the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which reauthorized funding for federal pipeline safety programs through 2015, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

The DOT has delegated its authority under these statutes to the PHMSA, which administers compliance with these statutes and has promulgated comprehensive safety standards and regulations for the transportation of natural gas by pipeline (49 Code of Federal Regulations (“CFR”) Part 192), as well as hazardous liquids by pipeline (49 CFR Part 195), including regulations for the design and construction of new pipeline systems or those that have been relocated, replaced or otherwise changed (Subparts C and D of 49 CFR, Part 195); pressure testing of new pipelines (Subpart E of 49 CFR Part 195); operation and maintenance of pipeline systems, including inspecting and reburying pipelines in the Gulf of Mexico and its inlets, establishing programs for public awareness and damage prevention, managing the integrity of pipelines in HCAs and managing the operation of pipeline control rooms (Subpart F of 49 CFR Part 195); protecting steel pipelines from the adverse effects of internal and external corrosion (Subpart H of 49 CFR Part 195); and integrity management requirements for pipelines in HCAs (49 CFR 195.452). In addition, on October 18, 2010, PHMSA issued an advance notice of proposed rulemaking on a range of topics relating to the safety of natural gas, crude oil and other hazardous liquids pipelines. On October 13, 2015, PHMSA issued a notice of proposed rulemaking which purposes changes to 49 CFR Part 195, followed shortly by proposed changes to 49 CFR Part 192, and is currently evaluating recommendations regarding potential changes to both Parts 192 and 195. We do not anticipate that we would be impacted by these regulatory initiatives to any greater degree than other similarly situated competitors.

We monitor the structural integrity of our pipelines through a program of periodic internal assessments using high resolution internal inspection tools, as well as hydrostatic testing and direct assessment, that conforms to federal standards. We accompany these assessments with a review of the data and repair anomalies, as required, to ensure the integrity of the pipeline. We then utilize sophisticated risk algorithms and a comprehensive data integration effort to ensure that the highest risk pipelines receive the highest priority for scheduling subsequent integrity assessments. We use external coatings and impressed current cathodic protection systems to protect against external corrosion. We conduct all cathodic protection work in accordance with National Association of Corrosion Engineers standards. We continually monitor, test and record the effectiveness of these corrosion inhibiting systems.

Pipeline Permitting

Pipeline construction and expansion is subject to government permitting and involves numerous regulatory environmental, political and legal uncertainties, most of which are beyond our control. We believe our operations are in substantial compliance with our permits.

Facility Safety

At manned facilities, the workplaces associated with the processing and storage facilities and the pipelines we operate are also subject to oversight pursuant to the federal Occupational Safety and Health Act, as amended, ("OSHA"), as well as comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard-communication standard requires that we maintain information about hazardous materials used or produced in operations, and that this information be provided to employees, state and local government authorities and citizens. We believe that we have conducted our operations in substantial compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances.

At unmanned facilities, the EPA's Risk Management Planning requirements at regulated facilities are intended to protect the safety of the surrounding public. The application of these regulations, which are often unclear, can result in increased compliance expenditures.

In general, we expect industry and regulatory safety standards to become stricter over time, resulting in increased compliance expenditures. While these expenditures cannot be accurately estimated at this time, we do not expect such expenditures will have a material adverse effect on our results of operations.

Notwithstanding the foregoing, PHMSA and one or more state regulators, including the Texas Railroad Commission, have recently sought to expand the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities in order to assess compliance with hazardous liquids pipeline safety requirements. These recent actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators; however, to the extent that such challenges are unsuccessful, midstream operators of NGL fractionation facilities and associated storage facilities may be required to make operational changes or modifications at their facilities to meet standards beyond current requirements. These changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation.

Product Quality Standards

Refined products and other hydrocarbon-based products that we transport are generally sold by us or our customers for consumption by the public. Various federal, state and local agencies have the authority to prescribe product quality specifications for products. The EPA has established sulfur specifications for natural gasoline sold as certified ethanol denaturant effective January 1, 2017. The EPA has also proposed product quality specification for natural gasoline used for blendstock in ethanol flex fuel. Changes in product quality specifications or blending requirements could reduce our throughput volumes, require us to incur additional handling costs or require capital expenditures. For example, different product specifications for different markets affect the fungibility of the products in our system and could require the construction of additional storage. In addition, changes in the product quality of the products we receive on our product pipeline systems could reduce or eliminate our ability to blend products.

EMPLOYEES

We are managed and operated by the board of directors and executive officers of MPLX GP, our general partner. Our general partner has the sole responsibility for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our general partner. Our general partner and its affiliates have approximately 2,800 full-time employees that provide services to us under our employee services agreements. We believe that our general partner and its affiliates have a satisfactory relationship with those employees.

AVAILABLE INFORMATION

General information about MPLX LP and our general partner, MPLX GP, including Governance Principles, Audit Committee Charter, Conflicts Committee Charter and Certificate of Limited Partnership, can be found at http://www.mplx.com. In addition, our Code of Business Conduct and Code of Ethics for Senior Financial Officers are available in this same location.

MPLX LP uses its website, www.mplx.com, as a channel for routine distribution of important information, including news releases, analyst presentations and financial information. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. These documents are also available in hard copy, free of charge, by contacting our Investor Relations office. In addition, our website allows investors and other interested persons to sign up to automatically receive email alerts when we post news releases and financial information on our website. Information contained on our website is not incorporated into this Annual Report on Form 10-K or other securities filings.

Item 1A. Risk Factors

You should carefully consider each of the following risks and all the other information set forth elsewhere in this Annual Report on Form 10-K in evaluating us and our common units. Some of these risks relate principally to our business, the business and operations of MPC and the industry in which we operate, while others relate principally to tax matters, and ownership of our common units and the securities markets generally.

Our business, financial condition, results of operations or cash flows could be materially and adversely affected by these risks, and, as a result, the trading price of our common units could decline.

Risks Relating to Our Business

Our substantial debt and other financial obligations could impair our financial condition, results of operations and cash flow, and our ability to fulfill our debt obligations.

We have significant debt obligations, which totaled $4.9 billion as of December 31, 2016, and we may incur significant additional debt obligations in the future. For example, in February 2017, we issued an additional $2.25 billion aggregate principal amount of senior notes. Our existing and future indebtedness may impose various restrictions and covenants on us that could have, or the incurrence of such debt could otherwise result in, material adverse consequences, including:

- We may have difficulties obtaining additional financing for working capital, capital expenditures, acquisitions, including the dropdowns proposed by MPC, or general partnership purposes on favorable terms, if at all, or our cost of borrowing may increase. Our funds available for operations, business opportunities and distributions to unitholders will also be reduced by that portion of our cash flow required to make interest payments on our debt.
- We may be at a competitive disadvantage compared to our competitors who have proportionately less debt, or we may be more vulnerable to, and have limited flexibility to respond to, competitive pressures or a downturn in our business or the economy generally.
- If our operating results are not sufficient to service our indebtedness, we may be required to reduce our distributions, reduce or delay our business activities, investments or capital expenditures, sell assets or issue equity, which could materially and adversely affect our financial condition, results of operations, cash flows and ability to make distributions to unitholders, as well as the trading price of our common units.
- The operating and financial restrictions and covenants in our revolving credit facility and any future financing agreements could restrict our ability to finance our operations or capital needs or to expand or pursue our business activities, which may, in turn, limit our ability to make distributions to our unitholders. Our ability to comply with these covenants may be impaired from time to time if the fluctuations in our working capital needs are not consistent with the timing for our receipt of funds from our operations.
- If we fail to comply with our debt obligations and an event of default occurs, our lenders could declare the outstanding principal of that debt, together with accrued interest, to be immediately due and payable, which may trigger defaults under our other debt instruments or other contracts. Our assets may be insufficient to repay such debt in full, and the holders of our units could experience a partial or total loss of their investment.

Global economic conditions may have adverse impacts on our business and financial condition and adversely impact our ability to access capital markets on acceptable terms.

Changes in economic conditions could adversely affect our financial condition and results of operations. A number of economic factors, including, but not limited to, gross domestic product, consumer interest rates, government spending sequestration, strength of U.S. currency versus other international currencies, consumer confidence and debt levels, retail trends, inflation and foreign currency exchange rates, may generally affect our business. Recessionary economic cycles, higher unemployment rates, higher fuel and other energy costs and higher tax rates may adversely affect demand for natural gas, NGLs and crude oil. Also, any tightening of the capital markets could adversely impact our ability to execute our long-term organic growth projects and meet our obligations to our customers and limit our ability to raise capital and, therefore, have an adverse impact on our ability to otherwise take advantage of business opportunities or react to changing economic and business conditions. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on our common units.

A significant decrease or delay in oil and natural gas production in our areas of operation, whether due to sustained declines in oil, natural gas and NGL prices, and natural declines in well production, or otherwise, may adversely affect our revenues, financial condition, and cash available for distribution.

A significant portion of our operations are dependent upon production from oil and natural gas reserves and wells, which will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels and the utilization rate of our facilities, we must continually obtain new oil, natural gas, NGL and refined product supplies, which depends in part on the level of successful drilling activity near our facilities.

We have no control over the level of drilling activity in the areas of our operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, drilling costs per Mcf or barrel, demand for hydrocarbons, operational challenges, access to downstream markets, the level of reserves, geological considerations, governmental regulations and the availability and cost of capital. Because of these factors, even if new oil or natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If we are not able to obtain new supplies of oil or natural gas to replace the natural decline in volumes from existing wells, throughput on our pipelines and the utilization rates of our facilities would decline, which could have a material adverse effect on our business, results of operations and financial condition and could reduce our ability to make distributions to our unitholders.

Decreases in energy prices can decrease drilling activity, production rates and investments by third parties in the development of new oil and natural gas reserves. The prices for oil, natural gas and NGLs depend upon factors beyond our control, including global and local demand, production levels, changes in interstate pipeline gas quality specifications, imports and exports, seasonality and weather conditions, economic and political conditions domestically and internationally and governmental regulations. Sustained periods of low prices could result in producers also significantly curtailing or limiting their oil and gas drilling operations which could substantially delay the production and delivery of volumes of oil, gas and NGLs to our facilities and adversely affect our revenues and cash available for distribution. This impact may also be exacerbated due to the extent of our commodity-based contracts, which are more directly impacted by changes in gas and NGL prices than our fee-based contracts due to frac spread exposure and may result in operating losses when natural gas becomes more expensive on a Btu equivalent basis than NGL products. In addition, our purchase and resale of gas and NGLs in the ordinary course exposes us to significant risk of volatility in gas or NGL prices due to the potential difference in the time of the purchases and sales and the potential difference in the price associated with each transaction, and direct exposure may also occur naturally as a result of our production processes. The significant fluctuation and decline in natural gas, NGL and oil prices currently occurring has adversely impacted our unit price, thereby increasing our distribution yield and cost of capital. Such impacts could adversely impact our ability to execute our long-term organic growth projects, satisfy our obligations to our customers, and make distributions to unitholders at intended levels, and may also result in non-cash impairments of long-lived assets or goodwill or other-than-temporary non-cash impairments of our equity method investments.

Our business plan and growth strategy requires, among other matters, access to new capital. An increased cost of capital could impair our ability to grow, our ability to make distributions to unitholders at our intended levels and trigger us to impair our goodwill and intangible assets.

Our ability to successfully operate our business, generate sufficient cash to pay the quarterly cash distributions to our unitholders and to allow for growth of our business and the growth of our distributions is subject to a number of risks and uncertainties, including economic and competitive factors beyond our control, which may impair our access to new capital. If the cost of capital becomes too expensive, we may not be able to raise the necessary funds from the equity market on satisfactory terms, if at all. We may be required to consider alternative financing strategies such as the formation of joint ventures or the sale of non-strategic assets, which may not provide the necessary capital, and our ability to develop or acquire strategic and accretive assets and finance growth projects will be limited. Factors that influence our cost of capital include market conditions, including our common unit price and the resultant distribution yield. When the price of our common units decreases, the resultant distribution yield increases, and our cost of capital increases accordingly. A significant drop in our unit price could also trigger an impairment of our goodwill and intangible assets. The significant decline in oil prices that occurred in 2015 and continued into 2016 has impacted our common unit price, as it has others in the energy industry. Although oil prices have begun to recover late in 2016, there is no assurance that this recovery will continue. The high and the low market price of our common units in 2016 ranged from a high of $39.46 to a low of $16.34. Given the significant change in MLP valuations and the resultant higher distribution yield environment the sector has experienced in 2015 and 2016, our cost of capital has increased, which could impair our ability to grow our business and make distributions to unitholders at intended levels.

We may not have sufficient cash from operations after the establishment of cash reserves and payment of our expenses, including cost reimbursements to MPC and its affiliates, to enable us to pay the minimum quarterly distribution to our unitholders.

We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distributions to our unitholders. The amount of cash we can distribute on our common units depends principally on the amount of cash we generate from our operations, which may fluctuate from quarter to quarter based on, among other things:

- the fees and tariff rates we charge and the margins we realize for our services and sales;
- the prices of, level of production of and demand for oil, natural gas, NGLs and refined products;
- the volumes of natural gas, crude oil, NGLs and refined products we gather, process, store, transport and fractionate;
- the level of our operating costs including repairs and maintenance;
- the relative prices of NGLs and crude oil, which impact the effectiveness of our hedging program; and
- prevailing economic conditions.

In addition, the actual amount of cash available for distribution may depend on other factors, some of which are beyond our control, including:

- the amount of our operating expenses and general and administrative expenses, including cost reimbursements to MPC in respect of those expenses;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions in our joint venture agreements, revolving credit facility or other agreements governing our debt;
- the level and timing of capital expenditures we make, including capital expenditures incurred in connection with our enhancement projects;

- the cost of acquisitions, if any; and
- the amount of cash reserves established by our general partner in its discretion.

Our inability, or limited ability, to control certain aspects of management of joint venture legal entities in which we have a partial ownership interest may mean that we will not receive the amount of cash we expect to be distributed to us. In addition, for entities where we have a noncontrolling ownership interest, or for entities that we operate but in which the noncontrolling interest owners have participative rights, we will be unable to control ongoing operational or other decisions, including the incurrence of capital expenditures that we may be required to fund, the incurrence of debt, or the pursuit of certain projects that we may want to pursue. Certain of our joint venture partners have the option to not make, or may otherwise cease making, capital contributions, so we may be required to fully fund capital or operating expenditures for the joint venture. For joint ventures we operate, we may not receive adequate reimbursement for all of the expenditures we incur to operate the joint venture. In addition, we may be unable to control the amount of cash we receive from the operation of these entities, which could adversely affect our ability to pay the minimum quarterly distribution to our unitholders.

Furthermore, the amount of cash we have available for distribution depends primarily on our cash flow and not solely on profitability, which is affected by non-cash items. As a result, we may make distributions during periods when we record net losses and may not make distributions during periods when we record net income.

We may not always be able to accurately estimate hydrocarbon reserves and expected production volumes; therefore, volumes we service in the future could be less than we anticipate.

We work closely with our producer customers in an effort to understand hydrocarbon reserves and expected production volumes. We periodically review or have outside consultants review hydrocarbon reserve information and expected production data that is publicly available or that is provided to us by our producer customers. However, we may not be able to accurately estimate hydrocarbon reserves and production volumes expected to be delivered to us for a variety of reasons, including the unavailability of sufficiently detailed information and unanticipated changes in producers' expected drilling schedules. Significant declines in oil, natural gas or NGL prices could also cause producers to curtail or limit drilling operations, which may result in the volumes delivered to us being less than anticipated. Accordingly, we may not have accurate estimates of total reserves serviced by our assets, the anticipated life of such reserves, or the expected volumes to be produced from those reserves. In such event, if we are unable to secure additional sources, then the volumes that we gather or process in the future could be less than anticipated. A decline in such volumes could have a material adverse effect on our results of operations and financial condition.

Our expansion of existing assets and the construction of new assets, if completed, may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks that could adversely impact our business, financial condition, results of operations and cash flows.

One of the ways we intend to grow our business is through the construction of, or additions to, our existing gathering, transportation, treating, processing, storage and fractionation facilities, which requires the expenditure of significant amounts of capital which may exceed our expectations. Construction involves many factors beyond our control including delays caused by third-party landowners, unavailability of materials, labor disruptions, environmental constraints, financing, accidents, weather and other factors. Additionally, we are subject to numerous regulatory, environmental, political, legal and inflationary uncertainties, including societal sentiment regarding the development and use of carbon based fuels, political pressures and the influence of environmental or other special interest groups, as well as stringent, lengthy and occasionally unreasonable or impractical federal, state and local permitting, zoning, consent, or authorizations requirements, or new laws, regulations, requirements or enforcement actions, which may cause us to incur additional capital expenditures, delay, interfere with or impair our construction activities, including by requiring the redesign of facilities, the acquisition of additional equipment, and relocations or rerouting of facilities, subject us to additional expenses or penalties and adversely affect our operations and cash flows available for distribution to unitholders. If we undertake these projects, we may not be able to complete them on schedule, or at all, or at the budgeted cost. We also may be required to incur additional costs and expenses in connection with the design and installation of our facilities due to their location and the surrounding terrain. We may be required to install additional facilities, incur additional capital and operating expenditures, or experience interruptions in or impairments of our operations to the extent that the facilities are not designed or installed correctly. For example, certain of our processing, fractionation and pipeline facilities are located in mountainous areas such as our Utica, Marcellus and southern Appalachian operations, which may require specially designed foundations, retaining walls and other structures or facilities. If such foundations, retaining walls or other facilities are not designed or installed correctly, do not perform as intended, or fail, we may be required to incur significant capital expenditures to correct or repair the deficiencies, or may incur significant damage to or loss of facilities, and our operations may be interrupted as a result of deficiencies or failures. In addition, such deficiencies may cause damages to the surrounding environment, including slope failures, stream impacts and other natural resource damages, and we may as a result also be subject to increased operating expenses or environmental penalties and fines. In addition, certain agreements with our customers contain substantial financial penalties and/or give the producer the right to repurchase certain assets and terminate their contracts with us if construction deadlines are not achieved. Any such penalty or contract termination could have a material adverse effect on our income from operations and cash available for distribution. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction may occur over an extended period of time, and we may not receive any material increases in revenues until after completion of the project, if at all.

Furthermore, we may have only limited oil, natural gas, NGL or refined product supplies committed to these facilities prior to their construction. We may construct facilities to capture anticipated future growth in production or satisfy anticipated market demand which does not materialize, the facilities may not operate as planned or may not be used at all. In order to attract additional oil, natural gas, NGL or refined product supplies from a customer, we may be required to order equipment and facilities, obtain rights of way or other land rights or otherwise commence construction activities for facilities that will be required to serve such customer's additional supplies prior to executing agreements with the customer. If such agreements are not executed, we may be unable to recover such costs and expenses. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough oil, natural gas, NGLs or refined products to achieve our expected investment return or result in immediate revenue increases, which could adversely affect our operations and cash available for distribution. Alternatively, oil, natural gas, NGL or refined product supplies committed to facilities under construction may be delivered prior to completion of such facilities, or we may otherwise have unexpected increase in volumes that could adversely affect our ability to expand our facilities. In such event, we may be required to temporarily utilize third-party facilities for such oil, natural gas, NGLs or refined products, which may increase our operating costs and reduce our cash available for distribution.

Due to capacity, market and other constraints relating to the growth of our business, we may experience difficulties in the execution of our business plan, which may increase our costs and reduce our revenues and cash available for distribution.

The successful execution of our business strategy is impacted by a variety of factors, including our ability to grow our business and satisfy our customers' requirements for gathering, processing, fractionation, marketing, transportation and storage services. Our ability to grow our business and satisfy our customers' requirements may be adversely affected by a variety of factors, including the following:

- more stringent permitting and other regulatory requirements;
- a limited supply of qualified fabrication and construction contractors, which could delay or increase the cost of the construction and installation of our facilities or increase the cost of operating our existing facilities;
- unexpected increases in the volume of oil, natural gas, NGLs and refined products being delivered to our facilities, which could adversely affect our ability to expand our facilities in a manner that is consistent with our customers' production or delivery schedules;

- changes in, or inability to meet, downstream gas, NGL, crude oil or refined product pipeline quality specifications, which could reduce the volumes of gas, NGLs, crude oil and refined products that we receive;
- scheduled maintenance, unexpected outages or downtime at our facilities or at upstream or downstream third-party facilities, which could reduce the volumes of oil, gas, NGLs and refined products that we receive; and
- market and capacity constraints affecting downstream oil, natural gas, NGL and refined products facilities, including limited gas and NGL capacity downstream of our facilities, limited railcar and NGL pipeline facilities and reduced demand or limited markets for certain NGL or refined products, which could reduce the volumes of oil, gas, NGLs and refined products that we receive and adversely affect the pricing received for NGLs.

If we are unable to successfully execute our business strategy, then our operating and capital expenditures may materially increase and our revenues and cash available for distribution may be adversely affected.

We engage in commodity derivative activities to mitigate the impact of commodity price volatility on our cash flows, but these activities may reduce our earnings, profitability and cash flows. In addition, we may not accurately predict future commodity price fluctuations, our risk management activities may impair our ability to benefit from price increases, and additional regulation of commodity derivative activities could adversely impact our ability to manage these risks.

Our operations expose us to fluctuations in commodity prices. We utilize derivative financial instruments related to the future price of crude oil, natural gas and certain NGLs with the intent of reducing volatility in our cash flows due to fluctuations in commodity prices.

The extent of our commodity price exposure is related largely to our contract mix and the effectiveness and scope of our derivative activities. We have a policy to enter into derivative transactions related to only a portion of the volume of our expected production or fuel requirements that are subject to commodity price volatility and, as a result, we expect to continue to have some direct commodity price exposure. Our actual future production or fuel requirements may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to settle all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, which could result in a substantial diminution of our liquidity. Alternatively, we may seek to amend the terms of our derivative financial instruments, including the extension of the settlement date of such instruments. Additionally, because we may use derivative financial instruments relating to the future price of crude oil to mitigate our exposure to NGL price risk, the volatility of our future cash flows and net income may increase if there is a change in the pricing relationship between crude oil and NGLs. As a result of these factors, our risk management activities may not be as effective as we intend in reducing the downside volatility of our cash flows and, in certain circumstances, may actually increase the volatility of our cash flows. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect and our risk management policies and procedures are not properly followed. For further information about our risk management policies and procedures, please read Item 8. Financial Statements and Supplementary Data—Note 16. Derivative Financial Instruments.

To the extent that we do not manage the commodity price risk relating to a position that is subject to commodity price risk and commodity prices move adversely, we could suffer losses. Such losses could be substantial and could adversely affect our operations and cash flows available for distribution. In addition, managing the commodity risk may actually reduce our opportunity to benefit from increases in the market or spot prices.

As a result of the Dodd-Frank Act, over-the-counter derivatives markets and entities are subject to regulation by the Commodities Futures Trading Commission (the "CFTC"), the SEC and other regulators. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. To the extent we engage in such transactions that are or become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we believe that we qualify for the end-user exception to the mandatory clearing requirements for swaps to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants may change the cost and availability of the swaps that we use for hedging. Additional mandatory clearing requirements could be imposed that may impair our ability to maintain over-the-counter hedging positions or require us to post collateral. The Dodd-Frank Act and its implementing regulations, including those not yet finalized, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, increase the administrative burden and regulatory risk associated with entering into certain derivative contracts, and increase our exposure to less credit-worthy counterparties. As a result, if we reduce our use of derivatives, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material adverse effect on our income from operations and cash flows available for distribution.

Due to an increased domestic supply of NGLs, we may be required to find alternative NGL market outlets and to rely more heavily on the export of NGLs, which may increase our operating costs or reduce the price received for NGLs and thereby reduce our cash available for distribution.

Due to increased production of natural gas, particularly in shale plays, there is an increased domestic supply of NGLs, which is currently outpacing, and could continue to outpace, domestic demand. As a result, we and our producer customers may need to continue to find alternate NGL market outlets and to rely more heavily on the export of NGLs. Our ability to find alternative NGL market outlets is dependent upon a variety of factors, including the construction and installation of additional NGL transportation infrastructure necessary to transport NGLs to other markets. In order to obtain committed transportation capacity, it may be necessary to make significant minimum volume commitments, with take or pay payments or deficiency fees if the minimum volume is not delivered. In other instances, we may enter into long-term sales arrangements, and we may incur shortfall or deficiency fees or be subject to other liabilities, including breach of contract claims, if we do not deliver the contracted quantity. We market NGLs on behalf of various of our producer customers, and as a result, we may make such commitments on behalf of those producer customers. We expect to be able to pass such commitments through to our producer customers, but if we were unable to do so, our operating costs may increase significantly, which could have a material adverse effect on our results of operations and our ability to make cash distributions. Similarly, our ability to export NGLs on a competitive basis is impacted by various factors, including:

- availability of sufficient railcar, tanker and terminalling facility capacity;
- currency fluctuations, particularly to the extent sales are denominated in foreign currencies as we do not currently hedge against currency fluctuations;
- compliance with additional governmental regulations and maritime requirements, including U.S. export controls and foreign laws, sanctions regulations and the Foreign Corrupt Practices Act;
- risks of loss resulting from non-payment or non-performance by international purchasers; and
- political and economic disturbances in the countries to which NGLs are being exported.

The above factors could increase our operating costs or adversely affect the price that we and our producer customers receive for NGLs, which in turn may have a material adverse effect on our volumes, revenues, income and cash available for distribution.

We depend on third parties for the oil, natural gas and refined products we gather, transport and store, the natural gas and refinery off-gas we process, and the NGLs we fractionate and stabilize at our facilities, and a reduction in these quantities could reduce our revenues and cash flow.

Although we obtain our supply of oil, natural gas, refinery off-gas, NGLs and refined products from numerous third-party producers and suppliers, a significant portion comes from a limited number of key producers/suppliers, who are usually under no obligation to deliver a specific volume to our facilities. If these key suppliers, or a significant number of other producers, were to decrease the supply of oil, natural gas, refinery off-gas, NGLs or refined products to our systems and facilities for any reason, we could experience difficulty in replacing those lost volumes. In some cases, the producers or suppliers are responsible for gathering or delivering oil, natural gas, refinery off-gas, NGLs or refined products to our facilities or we rely on other third parties to deliver volumes to us on behalf of the producers or suppliers. If such producers, suppliers or other third parties are unable, or otherwise fail to, deliver the volumes to our facilities, or if our agreements with any of these third parties terminate or expire such that our facilities are no longer connected to their gathering or transportation systems or the third parties modify the flow of natural gas, refinery off-gas or NGLs on those systems away from our facilities, the throughput on and utilization of our facilities may be reduced, or we may be required to incur significant capital expenditures to construct and install gathering pipelines or other facilities to be able to receive such volumes. Because our operating costs are primarily fixed, a reduction in the volumes delivered to us would result not only in a reduction of revenues, but also a decline in net income and cash flow.

We may not be able to retain existing customers, or acquire new customers, which would reduce our revenues and limit our future profitability.

A significant portion of our business comes from a limited number of key customers. The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other gatherers, processors, pipelines, and fractionators, and the price of, and demand for, natural gas, NGLs, crude oil and refined products in the markets we serve. Our competitors include large oil, natural gas, refining and petrochemical companies, some of which have greater financial resources, more numerous or greater capacity pipelines, processing and other facilities, greater access to natural gas, crude oil and NGL supplies than we do or other synergies with existing or new customers that we cannot provide. Our competitors may also include our joint venture partners, who in some cases are permitted to compete with us and may have a competitive advantage due to their familiarity with our business arising from our joint venture arrangements, as well as third parties on whom we rely to deliver natural gas, NGLs, crude oil and refined products to our facilities, who may have a competitive advantage due to their ability to modify the flow of natural gas, NGLs, crude oil and refined products on their systems away from our facilities. Additionally, our customers that gather gas through facilities that are not otherwise dedicated to us may develop their own processing and fractionation facilities in lieu of using our services.

As a consequence of the increase in competition in the industry, and the volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternative fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could affect our profitability.

The fees charged to third parties under our gathering, processing, transmission, transportation, fractionation, stabilization and storage agreements may not escalate sufficiently to cover increases in costs, or the agreements may not be renewed or may be suspended in some circumstances.

Our costs may increase at a rate greater than the fees we charge to third parties. Furthermore, third parties may not renew their contracts with us. Additionally, some third parties' obligations under their agreements with us may be permanently or temporarily reduced due to certain events, some of which are beyond our control, including force majeure events wherein the supply of natural gas, NGLs, crude oil or refined products are curtailed or cut-off due to events outside our control. If the escalation of fees is insufficient to cover increased costs, or if third parties do not renew or extend their contracts with us, or if third parties suspend or terminate their contracts with us, our financial results would suffer.

We are exposed to the credit risks of our key customers and derivative counterparties, and any material non-payment or non-performance by our key customers or derivative counterparties could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from non-payment or non-performance by our customers, which risks may increase during periods of economic uncertainty. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. This risk is further heightened due to the sustained decline of natural gas, NGL and oil prices that has occurred. With respect to our producer customers who have made acreage dedications to us, we may be exposed to additional risks to the extent that those customers become bankrupt and the acreage dedications are challenged and not upheld in bankruptcy. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our risk management policies and procedures are not properly followed. Any such material non-payment or non-performance could reduce our ability to make distributions to our unitholders.

Any strategic acquisitions, including the dropdowns proposed by MPC, are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.

In addition to organic growth, a component of our business strategy can include the expansion of our operations through strategic acquisitions, including the dropdowns proposed by MPC. Any acquisitions, including the dropdowns proposed by MPC, involve potential risks, including, amongst others:

- the validity of our assumptions about revenues, capital expenditures and operating costs of the acquired business or assets, as well as assumptions about achieving synergies with our existing business;
- the validity of our assessment of environmental and other liabilities, including legacy liabilities;
- the costs associated with additional debt or equity capital, which may result in a significant increase in our interest expense and financial leverage resulting from any additional debt incurred to finance such acquisitions, or the issuance of additional common units or preferred units on which we will make distributions, either of which could offset the expected accretion to our unitholders from such acquisition and could be exacerbated by volatility in the equity or debt capital markets;
- a failure to realize anticipated benefits, such as increased available cash per unit, enhanced competitive position or new customer relationships;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges; and
- the risk that our existing financial controls, information systems, management resources and human resources will need to grow to support future growth and we may not be able to react timely.

In addition, if we are unable to make accretive strategic acquisitions from MPC or third parties that increase the cash generated from operations per unit, whether due to an inability to identify attractive acquisition candidates, to negotiate acceptable purchase contracts, or to obtain financing for these acquisitions on economically acceptable terms, then our ability to successfully implement our business strategy may be impaired.

If we are unable to timely and successfully integrate the MarkWest Merger or our future acquisitions, including the dropdowns proposed to MPC, our future financial performance may suffer, and we may fail to realize all of the anticipated benefits of the transactions.

Our future growth may depend in part on our ability to integrate our future acquisitions. We cannot guarantee that we will successfully integrate the MarkWest Merger, the assets we may acquire in the dropdowns proposed by MPC, or any other acquisitions into our existing operations, or that we will achieve the desired profitability and anticipated results from such acquisitions. Failure to achieve such planned results could adversely affect our operations and cash available for distribution.

Significant acquisitions, including the MarkWest Merger and dropdowns proposed by MPC, present potential risks including:

- operating a significantly larger combined organization and integrating additional operations into ours;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographical area;
- the loss of customers or key employees from the acquired businesses;
- the diversion of management's attention from other existing business concerns;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- integrating personnel from diverse business backgrounds and organizational cultures; and
- consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition, if at all. Following an acquisition, we may discover previously unknown liabilities, including environmental liabilities, which could cause us to incur increased costs to address these liabilities or to attain or maintain compliance with applicable law. Our capitalization and results of operation may also change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we may consider in determining the application of these funds and other resources.

We are indemnified for liabilities arising from an ongoing remediation of property on which certain of our facilities are located and our results of operations and our ability to make distributions to our unitholders could be adversely affected if an indemnifying party fails to perform its indemnification obligations.

The prior third-party owner or operator of our Kenova, Boldman, Cobb, Kermit and Majorsville facilities has been or is currently involved in investigatory or remedial activities with respect to the real property underlying those facilities pursuant to regulatory orders with the EPA and various state regulatory agencies. The third party or its successor in interest has agreed to retain sole liability and responsibility for, and to indemnify us against, any environmental liabilities associated with these regulatory orders or the real property underlying these facilities to the extent such liabilities arose prior to the effective date of the agreements pursuant to which such properties were acquired or leased and to the extent not contributed to by us. In addition, the previous owner and/or operator of certain facilities on the real property on which our rail facility is constructed near Houston, Pennsylvania has been or is currently involved in investigatory or remedial activities related to AMD with respect to that real property. The third party has accepted liability and responsibility for, and has agreed to indemnify us against, any environmental liabilities associated with the AMD that are not exacerbated by us in connection with our operations. MPC has also agreed to indemnify us for certain environmental liabilities related to assets contributed to us by MPC in our Initial Offering or sold to us subsequently. Our results of operation and our ability to make cash distributions to our unitholders could be adversely affected if in the future any of these third parties fail to perform their indemnification obligations. In addition, from time to time, we have acquired, and may acquire in the future, facilities from third parties which previously have been or currently are the subject of investigatory, remedial or monitoring activities relating to environmental matters. In some cases, we may receive indemnification from the prior owner or operator for some or all of such liabilities, and in other cases we may accept some or all of such liabilities. There is no assurance that any such third parties will perform any such indemnification obligations, or that the obligations and liabilities that we may accept in connection with any such acquisition will not be larger than anticipated, and in such event, our results of operations and cash available for distribution could be adversely affected.

If foreign investment in us or our general partner exceeds certain levels, we could be prohibited from operating inland river vessels, which could materially and adversely affect our business, financial condition, results of operations and cash flows.

The Shipping Act of 1916 and Merchant Marine Act of 1920, which we refer to collectively as the Maritime Laws, generally require that vessels engaged in U.S. coastwise trade be owned by U.S. citizens. Among other requirements to establish citizenship, entities that own such vessels must be owned at least 75 percent by U.S. citizens. If we fail to maintain compliance with the Maritime Laws, we would be prohibited from operating vessels in the U.S. inland waters. Such a prohibition could materially and adversely affect our business, financial condition, results of operations and cash flows.

Risks Relating to our Industry

Certain of our pipelines may be subject to federal or state rate and service regulation, and the imposition and/or cost of compliance with such regulation could adversely affect our operations and cash flows available for distribution to our unitholders.

Some of our natural gas and NGL pipelines, and various of our crude oil and refined product pipelines are, or may in the future be, subject to siting, public necessity and/or service regulations by FERC and/or various state or other regulatory bodies, depending upon jurisdiction. FERC generally regulates the transportation of natural gas, NGLs, crude oil and refined products in interstate commerce and FERC’s regulatory authority includes: facilities construction, acquisition, extension or abandonment of services or facilities (for natural gas pipelines only); rates; operations; accounts and records; and depreciation and amortization policies. FERC’s action in any of these areas or modifications of its current regulations can adversely impact our ability to compete for business, the costs we incur in our operations, the construction of new facilities or our ability to recover the full cost of operating our pipelines. FERC also may conduct audits of these facilities, and if FERC determines that we are not in compliance with our tariff or applicable regulations, we may incur additional costs, expenses or penalties. For certain NGL product pipelines and for the crude oil and refined product common carrier pipelines, we have a FERC tariff on file and we may have additional common carrier pipelines in the future that may be subject to these requirements. We also own and are constructing pipelines that are carrying or are expected to carry NGLs owned by us across state lines between our processing and fractionation facilities that we believe are either not subject to FERC’s requirements for common carrier NGL pipelines or would otherwise meet the qualifications for a waiver from many of FERC’s reporting and filing requirements. However, we cannot provide assurance that FERC will not at some point find that some or all of these pipelines are subject to FERC’s requirements for common carrier pipelines and/or are otherwise not exempt from its reporting and filing requirements. Such a finding could subject us to potentially burdensome and expensive operational, reporting and other requirements as well as fines, penalties or other sanctions.

Most of our natural gas and NGL pipelines are generally not subject to regulation by FERC. The NGA specifically exempts natural gas gathering systems from FERC’s jurisdiction. Yet, such operations may still be subject to regulation by various state agencies. The applicable statutes and regulations generally require that our rates and terms and conditions of service provide no more than a fair return on the aggregate value of the facilities used to render services and that we offer service to our shippers on a not unduly discriminatory basis.

We cannot assure unitholders that FERC will not at some point determine that some or all of such pipelines are within its jurisdiction, and regulate such services, which could limit the rates that we may charge, increase our costs of operation, and subject us to fines, penalties or other sanctions. FERC rate cases can involve complex and expensive proceedings. For more information regarding regulatory matters that could affect our business, please read Item 1. Business—Rate and Other Regulation as set forth in this Annual Report on Form 10-K.

Some of our natural gas and NGL pipelines, and various of our crude oil and refined product pipelines, are subject to FERC's rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating our pipelines including a reasonable return.

A number of our pipelines provide interstate service that is subject to regulation by the FERC. The FERC prescribes rate methodologies for developing regulated tariff rates for these natural gas, interstate oil and products pipelines. The FERC's regulated tariff may not allow us to recover all of our costs of providing services. Changes in the FERC's approved rate methodologies, or challenges to our application of an approved methodology, could also adversely affect our rates. Additionally, shippers may protest (and the FERC may investigate) the lawfulness of tariff rates. The FERC can require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful and prescribe new rates prospectively.

MPC has agreed not to challenge, or to cause others to challenge or assist others in challenging, our tariff rates in effect during the term of our transportation services agreements with MPC. However, this agreement does not prevent other shippers or interested persons from challenging our tariff rates or proration rules; nor does it prevent regulators from reviewing our rates and tariffs on their own initiative. At the end of the term of each of our transportation services agreements with MPC, if the agreement is not renewed, MPC will be free to challenge, or to cause other parties to challenge or assist others in challenging, our tariffs in effect at that time.

Action by FERC could adversely affect our ability to establish reasonable rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against us could have a material adverse effect on our business, financial condition and results of operations.

If we are unable to obtain new rights-of-way or other property rights, or the cost of renewing existing rights-of-way or property rights increases, then we may be unable to fully execute our growth strategy, which may adversely affect our operations and cash flows available for distribution to unitholders.

The construction of additions to, or expansions of, our facilities may require us to obtain new rights-of-way or other property rights prior to constructing new plants, pipelines and other transportation and storage facilities. We may be unable to obtain such rights-of-way or other property rights to connect new natural gas supplies to our existing gathering lines, to connect our existing or future facilities to new natural gas, NGL, crude oil or refined product markets, or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new or renew existing rights-of-way or other property rights, including the renewal of leases for land on which our processing facilities are located. If the cost of obtaining new or renewing existing rights-of-way or other property rights increases, it may adversely affect our operations and cash flows available for distribution to unitholders. If we are unable to renew a lease for land on which any of our processing facilities are located, we may be required to remove our facilities from that site, which could require us to incur significant costs and expenses, disrupt our operations, and adversely affect our cash available for distribution.

Increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make distributions at our intended levels.

Our revolving credit facility and our loan agreement with MPC Investment have variable interest rates. Although interest rates have been low during the past several years, the United States Federal Reserve raised interest rates in December 2015 and December 2016, and have indicated that additional interest rate increases may occur in 2017. As a result, interest rates on our debt could be higher than current levels, causing our financing costs to increase accordingly. In addition, we may in the future refinance outstanding borrowings under our revolving credit facility with fixed-rate indebtedness. Interest rates payable on fixed-rate indebtedness typically are higher than the short-term variable interest rates that we pay on borrowings under our revolving credit facility. We also have other fixed-rate indebtedness that we may need or desire to refinance in the future prior to the applicable stated maturity. Furthermore, as with other yield-oriented securities, our unit price will be impacted by our cash distributions and the implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue equity or incur debt for acquisitions or other purposes and to make distributions at our intended levels.

Our business is subject to laws and regulations with respect to environmental, occupational safety and health, nuisance, zoning, land use and other regulatory matters, and the violation of, or the cost of compliance with, such laws and regulations could adversely affect our operations and cash flows available for distribution to our unitholders.

Numerous governmental agencies enforce federal, regional, state and local laws and regulations on a wide range of environmental, occupational safety and health, nuisance, zoning, land use, endangered species and other regulatory matters. We could be adversely affected by increased costs due to stricter pollution-control requirements or liabilities resulting from non-compliance with operating or other regulatory permits. Strict joint and several liability may be incurred without regard to fault, or the legality of the original conduct, under certain of the environmental laws for remediation of contaminated areas, including CERCLA, RCRA and analogous state laws. Private parties, including the owners of properties located near our storage, fractionation and processing facilities or through which our pipeline systems pass, also may have the right to pursue legal actions to enforce compliance, as well as seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. New, more stringent environmental laws, regulations and enforcement policies, the listing of additional species as endangered or threatened, and new, amended or re-interpreted permitting requirements, policies and processes, might adversely affect our operations and activities, and existing laws, regulations and policies could be reinterpreted or modified to impose additional requirements, delays or constraints on our construction of facilities or on our operations, increase our operating costs, or require our facilities to be aggregated into one air emissions permit or permit application. Federal, state and local agencies also could impose additional health and safety requirements, any of which could increase our operating costs. Local governments may adopt more stringent local permitting and zoning ordinances that impose additional time, place and manner restrictions, delays or constraints on our activities to construct and operate our facilities, require the relocation of our facilities, prevent or restrict the expansion of our facilities, or increase our costs to construct and operate our facilities, including the construction of sound mitigation devices.

In addition, we face the risk of accidental releases or spills associated with our operations, which could result in material costs and liabilities, including those relating to claims for damages to property, natural resources and persons, environmental remediation and restoration costs and governmental fines and penalties. Our failure to comply with or alleged non-compliance with environmental or safety-related laws and regulations could result in administrative, civil and criminal penalties, the imposition of investigatory and remedial obligations and even injunctions that restrict or prohibit some or all of our operations. For more information regarding the environmental, safety and other regulatory matters that could affect our business, please read Item 1. Business—Rate and Other Regulation, Item 1. Business—Environmental Regulation, and Item 1. Business—Pipeline Safety, each as set forth in this Annual Report on Form 10-K.

Climate change legislation or regulations restricting emissions of GHGs or methane could result in increased operating costs, reduced demand for our services and adversely affect the cash flows available for distribution to our unitholders.

As a consequence to an EPA administrative conclusion that GHGs present an endangerment to public health and the environment, the EPA adopted regulations establishing PSD construction and Title V operating permit requirements for GHG emissions from certain large stationary sources that are potential major sources of certain principal, or criteria, pollutant emissions. In addition, the EPA and states are gathering information on existing facilities in various industries, which may be used to support potential future regulation of carbon emissions, and states may seek to adopt their own permitting programs under state laws that require permit reviews of large stationary sources emitting only GHGs. If we were to become subject to Title V and PSD permitting requirements due to non-GHG criteria pollutants, or if EPA or states implemented more stringent permitting requirements relating to GHG emissions without regard to non-GHG criteria pollutants, we may be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future. In addition, we may experience substantial delays or possible curtailment of construction or projects in connection with applying for, obtaining or maintaining preconstruction and operating permits, we may encounter limitations on the design capacities or size of facilities, and our construction and operating costs may materially increase.

Congress has from time to time considered legislation to reduce emissions of GHGs, but, in the absence of federal climate legislation in the United States in recent years, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. If Congress were to undertake comprehensive tax reform, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for oil, natural gas, NGLs and products derived therefrom.

These requirements or enforcement thereof, or the adoption of any new legislation or regulations that requires additional reporting, monitoring or recordkeeping of GHGs, limits emissions of GHGs from our equipment and operations, or imposes a carbon tax, could adversely affect our operations and materially restrict or delay our ability to obtain air permits for new or modified facilities, could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we process or fractionate. In May 2016, EPA finalized new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. This rule is currently being challenged in court by various affected states. Concurrently, the Commonwealth of Pennsylvania has also proposed similar regulations that have not yet been finalized. We may experience delays in the construction and installation of new facilities due to more stringent permitting requirements, incur additional costs to reduce methane emissions associated with our operations or be required to aggregate the emissions from separate facilities for permitting purposes or to relocate one or more of our facilities due to more stringent emissions standards. To the extent that we incur additional costs or delays, our cash available for distribution may be adversely affected.

Our producer customers or suppliers may also experience similar issues, which may adversely impact their drilling schedules and production volumes and reduce the volumes delivered to us. For more information regarding greenhouse gas and methane emission and regulation, please read Item 1. Business—Environmental Matters—Climate Change.

Finally, for a variety of reasons, natural and/or anthropogenic, some members of the scientific community believe that climate changes could occur which could have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations, which in turn could adversely affect our cash available for distribution to our unitholders.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could delay or impede oil or gas production or result in reduced volumes available for us to gather, transport, store, process and fractionate.

We do not conduct hydraulic fracturing operations, but we do provide gathering, processing, transportation, storage and fractionation services with respect to natural gas, oil, NGLs and refined products produced by our customers as a result of such operations. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but several federal agencies have asserted regulatory authority over certain aspects of the process, including the EPA and BLM. In addition, Congress has from time to time considered legislation to provide for additional regulation of hydraulic fracturing. Also, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult to complete natural gas and oil wells in shale formations and increase our producers' costs of compliance. This could significantly reduce the volumes delivered to us, which could adversely impact our earnings, profitability and cash flows.

We are subject to operating and litigation risks that may not be covered by insurance.

Our industry is subject to numerous operating hazards and risks incidental to gathering, processing, transporting, fractionating and storing natural gas and NGLs and to transporting and storing crude oil and refined products. These include:

- damage to pipelines, plants, storage facilities, barges, related equipment and surrounding properties caused by floods, hurricanes and other natural disasters and acts of terrorism;
- inadvertent damage from vehicles and construction and farm equipment;
- leakage of crude oil, natural gas, NGLs, refined products and other hydrocarbons into the environment, including groundwater;
- fires and explosions; and
- other hazards and conditions, including those associated with various hazardous pollutant emissions, high-sulfur content, or sour gas, and proximity to businesses, homes, or other populated areas, that could also result in personal injury and loss of life, pollution and suspension of operations.

As a result, we may be a defendant in various legal proceedings and litigation arising from our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates or at all, and, even if we are able to obtain such insurance, we may not be able to recover amounts from the insurance carrier for events that we believe are covered. In addition, insurance carriers now require broad exclusions for losses due to war risk and terrorist acts. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our operations and cash available for distribution.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs, and the expansion of pipeline safety laws and regulations could require us to use more comprehensive and stringent safety controls and subject us to increased capital and operating costs.

The DOT through the PHMSA has adopted regulations requiring pipeline operators to develop integrity management programs for gas transmission and hazardous liquids pipelines located where a leak or rupture could do the most harm. The regulations require the following of operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;

- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, the maximum civil penalty for federal pipeline safety violations has increased from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations. Over the past several years, PHMSA has published new regulations, and issued notices for additional proposed regulations, to expand pipeline safety requirements.

In addition, PHMSA and other state regulators have recently expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities to assess compliance with hazardous liquids pipeline safety requirements, which actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators. The adoption of these and other laws or regulations that apply more comprehensive or stringent safety standards to gas, NGL, crude oil and refined product lines or other facilities, or the expansion of regulatory inspections by PHMSA and other state regulators described above, could require us to install new or modified safety controls, pursue added capital projects, make modifications or operational changes, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased capital and operational costs or operational delays that could be significant and have a material adverse effect on our financial position or results of operations and ability to make distributions to our unitholders.

Some states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. These regulations have raised operating costs for the industry, and compliance with such laws and regulations may cause us to incur potentially material capital expenditures associated with the construction, maintenance, and upgrading of equipment and facilities.

The United States inland waterway infrastructure is aging and planned and unplanned maintenance may adversely affect our operations.

Maintenance of the United States inland waterway system is vital to our marine transportation operations. The system is composed of over 12,000 miles of commercially navigable waterway, supported by over 240 locks and dams designed to provide flood control, maintain pool levels of water in certain areas of the country and facilitate navigation on the inland river system. The United States inland waterway infrastructure is aging, with more than half of the locks over 50 years old. As a result, due to the age of the locks, planned and unplanned maintenance may create more frequent outages, resulting in delays and additional operating expenses. Part of the costs for new construction and major rehabilitation of locks and dams is funded by marine transportation companies through taxes and the other portion is funded by general federal tax revenues. Failure of the federal government to adequately fund infrastructure maintenance and improvements in the future would have a negative impact on our ability to deliver products to our customers on a timely basis. Furthermore, any additional user taxes that may be imposed in the future to fund infrastructure improvements would increase our operating expenses.

Interruptions in operations at any of our facilities or MPC’s refining operations may adversely affect our operations and cash flows available for distribution to our unitholders.

Our operations depend upon the infrastructure that we have developed, including processing and fractionation plants, storage facilities, gathering and transportation facilities, various other means of transportation and marketing services. Any significant interruption at these facilities or pipelines, MPC’s refining operations or in our ability to gather, transport, or store natural gas, NGLs, crude oil or other refined products to or from these facilities or pipelines for any reason, or to market or transport the natural gas, crude oil, NGLs or refined products, would adversely affect our operations and cash flows available for distribution to our unitholders. In some cases, these events may also adversely affect the pricing received for NGLs, and may reduce the volumes of oil, gas, NGLs and refined products that we receive.

Operations at our facilities or MPC's refining operations could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within our control, such as:

- unscheduled turnarounds or catastrophic events, including damages to pipelines and facilities, related equipment and surrounding properties caused by earthquakes, tornadoes, hurricanes, floods, fires, severe weather, explosions and other natural disasters;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown;
- a disruption in the supply of natural gas, NGLs, crude oil or refined products to our pipelines, barges, processing and fractionation plants and associated facilities;
- disruption in our supply of power, water and other resources necessary to operate our facilities;
- a marine accident or spill event could close a portion of the inland waterway system;
- damage to our facilities resulting from gas, crude oil, NGLs or refined products that do not comply with applicable specifications; and
- inadequate fractionation, transportation or storage capacity or market access to support production volumes, including lack of availability of rail cars, barges, trucks and pipeline capacity, or market constraints, including reduced demand or limited markets for certain NGL products.

Our NGL fractionation, storage and marketing operations in the Marcellus and Utica regions are integrated, and as a result, it is possible that an interruption of these operations may impact operations in the other regions, which may exacerbate the impacts of such interruption.

The construction and operation of certain of our facilities in our G&P segment may be impacted by surface or subsurface mining operations by one or more third parties, which could adversely impact our construction activities or cause subsidence or other damage to our facilities. In such event, our construction may be prevented or delayed, or the costs and time increased, or our operations at such facilities may be impaired or interrupted, and we may not be able to recover the costs incurred for delays or to relocate or repair our facilities, from such third parties.

In addition, our marine transportation business is subject to weather conditions on a daily basis. Adverse weather conditions such as high or low water on the inland waterway systems, fog and ice, tropical storms, hurricanes and tsunamis on both the inland waterway systems and throughout the United States coastal waters can impair the operating efficiencies of the marine fleet. Such adverse weather conditions can cause a delay, diversion or postponement of shipments of products and are beyond our control. In addition, adverse water and weather conditions can negatively affect a towing vessel's performance, tow size, loading drafts, fleet efficiency, place limitations on night passages and dictate horsepower requirements.

Our operations depend on the use of information technology systems that could be the target of industrial espionage or cyber-attack.

Our business has become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications for the gathering and processing of natural gas, the gathering, fractionation, transportation and marketing of NGLs, and the gathering, storage and transportation of crude oil and refined products. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our systems and networks, as well as those of our customers, vendors and counterparties, may become the target of cyber-attacks or information security breaches, which in turn could result in the unauthorized release and misuse of confidential or proprietary information as well as disrupt our operations or damage our facilities or those of third parties, which could have a material adverse effect on our revenues and increase our operating and capital costs, which could reduce the amount of cash otherwise available for distribution. Additionally, as cyber incidents continue to evolve we may be required to incur additional costs to modify or enhance our systems or in order to try to prevent or remediate any such attacks. To protect against such attempts of unauthorized access or attack, we have implemented infrastructure protection technologies and disaster recovery plans. There can be no guarantee such plans, to extent they are in place, will be effective.

Terrorist attacks aimed at our facilities or that impact our customers or the markets we serve could adversely affect our business.

The U.S. government has issued warnings that energy assets in general, and the nation's pipeline and terminal infrastructure in particular, may be future targets of terrorist organizations. The threat of terrorist attacks has subjected our operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business. Similarly, any future terrorist attacks that severely disrupt the markets we serve could materially and adversely affect our results of operations, financial position and cash flows.

Risks Relating to the Business and Operations of MPC

MPC accounted for a large portion of our revenues in 2016 and will continue to do so on a go-forward basis. If MPC changes its business strategy, is unable to satisfy its obligations to us or significantly reduces the volumes transported through our facilities or stored at our storage assets, our revenues would decline and our financial condition, results of operations, cash flows, and ability to make distributions to our unitholders would be materially and adversely affected.

For the year ended December 31, 2016, excluding revenues attributable to volumes shipped by MPC under joint tariffs with third parties that were treated as third-party revenues for accounting purposes, MPC accounted for approximately 30 percent of our revenues and other income, including 92 percent of the revenues and other income within our L&S segment, and we believe MPC will continue to account for a large portion of our revenues on a go forward basis. As we expect to continue to derive a portion of our revenues from MPC for the foreseeable future, any event that materially and adversely affects MPC's financial condition, results of operations or cash flows may adversely affect our ability to sustain or increase distributions to our unitholders. Accordingly, we are indirectly subject to the operational and business decisions and risks of MPC, the most significant of which include the following:

- the timing and extent of changes in commodity prices and demand for MPC's products, and the availability and costs of crude oil and other refinery feedstocks;
- a material decrease in the refining margins at MPC's refineries;
- the risk of contract cancellation, non-renewal or failure to perform by MPC's customers, and MPC's inability to replace such contracts and/or customers;
- disruptions due to equipment interruption or failure at MPC's facilities or at third-party facilities on which MPC's business is dependent;
- any decision by MPC to temporarily or permanently alter, curtail or shut down operations at one or more of its refineries or other facilities and reduce or terminate its obligations under our transportation and storage services agreements;
- changes to the routing of volumes shipped by MPC on our crude oil and product pipeline systems or the ability of MPC to utilize third-party pipeline connections to access our pipeline systems;
- MPC's ability to remain in compliance with the terms of its outstanding indebtedness;

- changes in the cost or availability of third-party pipelines, terminals and other means of delivering and transporting crude oil, feedstocks, refined products and other hydrocarbon-based products;
- state and federal environmental, economic, health and safety, energy and other policies and regulations, and any changes in those policies and regulations;
- environmental incidents and violations and related remediation costs, fines and other liabilities;
- operational hazards and other incidents at MPC's refineries and other facilities, such as explosions and fires, that result in temporary or permanent shut downs of those refineries and facilities;
- changes in crude oil and product inventory levels and carrying costs; and
- disruptions due to hurricanes, tornadoes or other forces of nature.

We have no control over MPC's business decisions and operations, and MPC may elect to pursue a business strategy that does not favor us and our business. In addition, significant stockholders of MPC may attempt to affect changes at MPC or acquire control of the company, which could impact the pursuit of MPC's business strategies. Campaigns by stockholders to affect changes at publicly traded companies are sometimes led by investors seeking to increase short-term stockholder value through actions such as financial restructuring, increased debt, special dividends, stock repurchases or sales of assets or the entire company. As a result, stockholder campaigns at MPC could directly or indirectly adversely affect our results of operations and financial condition and our ability to sustain or increase distributions to our unitholders.

MPC may suspend, reduce or terminate its obligations under our transportation and storage services agreements in some circumstances, which would have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

Our transportation and storage services agreements with MPC include provisions that permit MPC to suspend, reduce or terminate its obligations under the applicable agreement if certain events occur. These events include a material breach of the applicable agreement by us, MPC being prevented from transporting its full minimum volume commitment because of capacity constraints on our pipelines, certain force majeure events that would prevent us from performing some or all of the required services under the applicable agreement and MPC's determination to suspend refining operations at one of its refineries. MPC has the discretion to make such decisions notwithstanding the fact that they may significantly and adversely affect us. These actions could result in a suspension, reduction or termination of MPC's obligations under one or more transportation and storage services agreements.

Any such reduction, suspension or termination of MPC's obligations would have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

If MPC satisfies only its minimum obligations under, or if we are unable to renew or extend, the transportation and storage services agreements we have with MPC, or if MPC elects to use credits upon the expiration or termination of a transportation services agreement, our cash available for distribution will be materially and adversely affected.

MPC is not obligated to use our services with respect to volumes of crude oil or products in excess of the minimum volume commitments under the transportation services agreements with us. Our cash available for distribution will be materially and adversely affected to the extent that we do not transport volumes in excess of the minimum volume commitments under our transportation services agreements or if MPC's obligations under our transportation and storage services agreements are suspended, reduced or terminated. In addition, the initial terms of MPC's obligations under those agreements range from three to 10 years. If MPC fails to use our assets and services after expiration of those agreements and we are unable to generate additional revenues from third parties, our ability to make distributions to unitholders may be materially and adversely affected.

In addition, under our transportation services agreements, MPC must pay us a deficiency payment if it fails to transport its minimum throughput commitment. MPC may then apply the amount of any such deficiency payments as a credit for volumes transported on the applicable pipeline system in excess of its minimum volume commitment during the following four quarters or eight quarters under the terms of the applicable transportation services agreement. Upon the expiration or termination of a transportation services agreement, MPC may use any remaining credits against any volumes shipped by MPC on the applicable pipeline system for the succeeding four or eight quarters, as applicable, without regard to any minimum volume commitment that may have been in place during the term of the agreement. If that were to occur, we would not receive any cash payments for volumes shipped on the applicable pipeline system until any such remaining credits were fully used or until the expiration of the applicable four or eight quarter period.

MPC's level of indebtedness, the terms of its borrowings and its credit ratings could adversely affect our ability to grow our business and our ability to make distributions to our unitholders. Our ability to obtain credit in the future may also be adversely affected by MPC's credit rating.

MPC must devote a portion of its cash flows from operating activities to service its indebtedness, and therefore, cash flows may not be available for use in pursuing its growth strategy. Furthermore, a higher level of indebtedness at MPC in the future increases the risk that it may default on its obligations to us under our transportation and storage services agreements. As of December 31, 2016, MPC had consolidated long-term indebtedness of approximately $11 billion, of which $6 billion was a direct obligation of MPC. The covenants contained in the agreements governing MPC's outstanding and future indebtedness may limit its ability to borrow additional funds for development and make certain investments and may directly or indirectly impact our operations in a similar manner.

Furthermore, if MPC were to default under certain of its debt obligations, there is a risk that MPC's creditors would attempt to assert claims against our assets during the litigation of their claims against MPC. The defense of any such claims could be costly and could materially impact our financial condition, even absent any adverse determination. If these claims were successful, our ability to meet our obligations to our creditors, make distributions and finance our operations could be materially and adversely affected.

MPC's long-term credit ratings are currently investment grade. If these ratings are lowered in the future, the interest rate and fees MPC pays on its credit facilities may increase. Credit rating agencies will likely consider MPC's debt ratings when assigning ours because of MPC's ownership interest in us, the significant commercial relationships between MPC and us, and our reliance on MPC for a portion of our revenues. If one or more credit rating agencies were to downgrade the outstanding indebtedness of MPC, we could experience an increase in our borrowing costs or difficulty accessing the capital markets. Such a development could adversely affect our ability to grow our business and to make distributions to our unitholders.

Risks Relating to Tax Matters

Our tax treatment depends on our status as a partnership for federal income tax purposes as well as our not being subject to a material amount of entity level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes, or we become subject to a material amount of entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this.

A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on our current operations, we believe that we are treated as a partnership rather than as a corporation for such purposes; however, a change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes. We have requested and received a favorable ruling from the IRS on the treatment of a portion of our “qualifying income.” The IRS may adopt positions that differ from the ones we take. A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any IRS contest will reduce our cash available for distribution to unitholders.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35 percent, and likely would pay state and local income tax at varying rates. Distributions to unitholders generally would be taxed again as corporate dividends, and no income, gains, losses, deductions, or credits would flow through to our unitholders. Treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units. Changes in current state law may subject us to additional entity-level taxation by individual states. Imposition of any such additional taxes on us will substantially reduce the cash available for distribution to unitholders.

Our partnership agreement provides that, if a law is enacted or an existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The sale or exchange of 50 percent or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50 percent or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50 percent threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution.

The IRS has made no determination as to our status as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

Our unitholders will be required to pay taxes on their share of income even if they do not receive any distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no distributions from us. Our unitholders may not receive distributions from us equal to their share of our taxable income or even equal to the actual tax liability that result from that income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in their common units, the amount, if any, of such prior excess distributions with respect to their units will, in effect, become taxable income to the unitholder if the common units are sold at a price greater than the unitholder's tax basis in those common units, even if the price the unitholder receives is less than the unitholder's original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, if a unitholder sells units, the unitholder may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Non-U.S. persons will also potentially have tax filings and payment obligations in additional jurisdictions. Tax-exempt entities and non-U.S. persons should consult their tax advisor before investing in our common units.

We treat each purchaser of common units as having the same tax benefits without regard to the actual units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

To maintain the uniformity of the economic and tax characteristics of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.

Our unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently conduct business in approximately 16 states. Many of these states currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is our unitholders' responsibility to file all U.S. federal, state and local tax returns.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, or our allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

A unitholder who loans his common units to a "short seller" to cover a short sale of common units (i) may be considered as having disposed of the loaned common units, (ii) may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and (iii) may recognize gain or loss from such disposition.

Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time.

From time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded limited partnerships, including as a result of any fundamental tax reform. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes or increase the amount of taxes payable by unitholders in publicly traded partnerships. Any reductions to the U.S. federal income tax rates applicable to individuals and corporations could cause the rate of return on investments in our common units to be relatively less attractive as compared to investments in shares of corporations, which in turn could adversely affect our unit price and increase our cost of capital. In addition, as to possible additional legislation, including any fundamental tax reform, we cannot predict whether any proposals will be introduced, reintroduced or ultimately enacted. Any such changes could affect us and negatively impact the value of an investment in our units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between existing unitholders and unitholders who purchase our units based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so (or choose to do so) under all circumstances. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be reduced.

Risks Relating to Ownership of our Common Units

Our general partner and its affiliates, including MPC, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to our detriment and that of our unitholders. Additionally, we have no control over MPC's business decisions and operations, and MPC is under no obligation to adopt a business strategy that favors us.

MPC owns our general partner and an approximate 23.5 percent limited partner interest (including the Class B units on an as-converted basis) in us as of February 13, 2017. Although our general partner has a duty to manage us in a manner that is not adverse to the best interests of our partnership and our unitholders, the directors and officers of our general partner also have a duty to manage our general partner in a manner that is not adverse to the best interests of its owner, MPC.

Conflicts of interest may arise between MPC and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, the general partner may favor its own interests and the interests of its affiliates, including MPC, over the interests of our common unitholders, which may occur under our partnership agreement without being independently reviewed by the conflicts committee. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires MPC to pursue a business strategy that favors us or utilizes our assets, which could involve decisions by MPC to increase or decrease refinery production, shut down or reconfigure a refinery, or pursue and grow particular markets. MPC's directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders of MPC;
- MPC, as a significant customer, has an economic incentive to cause us to not seek higher tariff rates, even if such higher rates or fees would reflect rates and fees that could be obtained in arm's-length, third-party transactions;
- MPC may be constrained by the terms of its debt instruments from taking actions, or refraining from taking actions, that may be in our best interests;
- our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner's liabilities and restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner will determine the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner will determine the amount and timing of many of our cash expenditures and whether a cash expenditure is classified as an expansion capital expenditure, which would not reduce operating surplus, or a maintenance capital expenditure, which would reduce our operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner and the amount of adjusted operating surplus generated in any given period;
- our general partner will determine which costs incurred by it are reimbursable by us and may cause us to pay it or its affiliates for any services rendered to us;
- our general partner may cause us to borrow funds in order to permit the payment of distributions, even if the borrowing is to allow us to pay the general partner's incentive distribution rights;
- our partnership agreement permits us to classify up to $60 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the general partner interest or the incentive distribution rights;
- our partnership agreement does not restrict our general partner from entering into additional contractual arrangements with it or its affiliates on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if it and its affiliates own more than 85 percent of the common units;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates, including our transportation and storage services agreements with MPC;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of

the conflicts committee of the board of directors of our general partner, which we refer to as our conflicts committee, or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers, directors and owners. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

Our partnership agreement requires that we distribute all of our available cash to our unitholders. As a result, we expect to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. Therefore, to the extent we are unable to finance our growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we will distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may reduce the amount of cash available to distribute to our unitholders.

Our general partner has certain incentive distribution rights that reduce the amount of our cash available for distribution to our common unitholders.

Our general partner currently holds a general partner interest in us that entitles it to receive two percent of all distributions paid to our common unitholders and incentive distribution rights that entitle it to receive an increasing percentage (13 percent, 23 percent and 48 percent) of the cash that we distribute to our common unitholders from available cash after the minimum quarterly distribution and certain target distribution levels have been achieved. The maximum distribution right for our general partner to receive 48 percent of any distributions paid to our common unitholders does not include any distributions that our general partner or its affiliates may receive on common or general partner units that they own. Throughout 2016, our general partner was at the top tier of the incentive distribution rights scale. Because a higher percentage of our cash is allocated to our general partner due to these incentive distribution rights, it will be more difficult for us to increase the amount of distributions to our unitholders and our cost of capital will be higher, making investments, capital expenditures and acquisitions, and therefore, future growth, by us more costly. In January 2017, MPC announced that it expects to exchange the general partner’s incentive distribution rights for common units in conjunction with the completion of the expected dropdowns of midstream assets. However, there is no assurance that this transaction will occur in 2017, or at all. If such a transaction does occur, it would likely result in a substantial increase in the number of common units outstanding. As a result, our unitholders’ proportionate ownership in us will decrease, it may be more difficult for us to maintain or increase our distributions to unitholders and the amount of cash available for distribution for each unit may decrease, the relative voting strength of each previously outstanding unit may be diminished and the market price of our common units may decline.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our common units with contractual standards governing its duties and restricts the remedies available to unitholders for actions taken by our general partner.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing. Our general partner is entitled to consider only the interests and factors that it desires and is relieved of any duty or obligation to give consideration to any interest of, or factors affecting, us, our affiliates or our limited partners.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith;
- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- provides that our general partner will not be in breach of its obligations under our partnership agreement or its fiduciary duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is approved in accordance with, or otherwise meets the standards set forth in, our partnership agreement.

In connection with a transaction with an affiliate or a conflict of interest, our partnership agreement provides that any determination by our general partner must be made in good faith, and that our conflicts committee and the board of directors of our general partner are entitled to a presumption that they acted in good faith. In any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. By purchasing a common unit, a unitholder is treated as having consented to the provisions in our partnership agreement, including the provisions discussed above.

Unitholders have very limited voting rights and, even if they are dissatisfied, they have limited ability to remove our general partner without its consent.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the board of directors of our general partner and will have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner is chosen by the members of our general partner, which are wholly-owned subsidiaries of MPC. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The vote of the holders of at least 66⅔ percent of all outstanding common units voting together as a single class is required to remove our general partner. As of February 13, 2017, our general partner and its affiliates owned approximately 24.2 percent of the common units (excluding common units held by officers and directors of our general partner and MPC). As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Furthermore, unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20 percent or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

If unitholders are not both citizenship-eligible holders and rate-eligible holders, their common units may be subject to redemption.

In order to avoid (1) any material adverse effect on the maximum applicable rates that can be charged to customers by our subsidiaries on assets that are subject to rate regulation by the FERC or analogous regulatory body, and (2) any substantial risk of cancellation or forfeiture of any property, including any governmental permit, endorsement or other authorization, in which we have an interest, we have adopted certain requirements regarding those investors who may own our common units. Citizenship eligible holders are individuals or entities whose nationality, citizenship or other related status does not create a substantial risk of cancellation or forfeiture of any property, including any governmental permit, endorsement or authorization, in which we have an interest, and will generally include individuals and entities who are U.S. citizens. Rate eligible holders are individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity's owners are subject to such taxation. If unitholders are not persons who meet the requirements to be citizenship eligible holders and rate eligible holders, they run the risk of having their units redeemed by us at the market price as of the date three days before the date the notice of redemption is mailed. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. In addition, if unitholders are not persons who meet the requirements to be citizenship eligible holders, they will not be entitled to voting rights.

Cost reimbursements, which will be determined in our general partner's sole discretion, and fees due our general partner and its affiliates for services provided will be substantial and will reduce our cash available for distribution.

Under our partnership agreement, we are required to reimburse our general partner and its affiliates for all costs and expenses that they incur on our behalf for managing and controlling our business and operations. Except to the extent specified under our omnibus agreement or our employee services agreements, our general partner determines the amount of these expenses. Under the terms of the omnibus agreement, we will be required to reimburse MPC for the provision of certain general and administrative services to us. Under the terms of our employee services agreements, we have agreed to reimburse MPC or its affiliates for the provision of certain operational and management services to us in support of our facilities. Our general partner and its affiliates also may provide us other services for which we will be charged fees as determined by our general partner. Payments to our general partner and its affiliates will be substantial and will reduce the amount of cash available for distribution to unitholders.

Our general partner interest, the control of our general partner and the incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of MPC to transfer its membership interest in our general partner to a third party. The new partners of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and to control the decisions taken by the board of directors and officers.

Additionally, our general partner may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its incentive distribution rights. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood of MPC selling or contributing additional midstream assets to us, as MPC would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

We may issue additional units without unitholder approval, which will dilute limited unitholder interests.

At any time, including in connection with the dropdowns proposed by MPC, we may issue an unlimited number of limited partner interests of any type, including limited partner interests that are convertible into our common units, without the approval of our unitholders and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such limited partner interests. Further, neither our partnership agreement nor our bank revolving credit facility prohibits the issuance of additional preferred units, Class B units, or other equity securities that may effectively rank senior to our common units as to distributions or liquidations. The issuance by us of additional common units, preferred units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- it may be more difficult to maintain or increase our distributions to unitholders, and the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

MPC may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of December 31, 2016, MPC held 86,619,313 common units. Additionally, we have agreed to provide MPC with certain registration rights. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Affiliates of our general partner, including MPC, may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Neither our partnership agreement nor our omnibus agreement will prohibit MPC or any other affiliates of our general partner from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, MPC and other affiliates of our general partner may acquire, construct or dispose of additional midstream assets in the future without any obligation to offer us the opportunity to purchase any of those assets. As a result, competition from MPC and other affiliates of our general partner could materially and adversely impact our results of operations and cash available for distribution to unitholders.

Our general partner has a limited call right that may require unitholders to sell common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 85 percent of our common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of such units.

A unitholder's liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made non-recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some jurisdictions. A unitholder could be liable for our obligations as if they were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- a unitholder's right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable for the obligations of the transferor to make contributions to the partnership that are known to the transferee at the time of the transfer and for unknown obligations if the liabilities could be determined from our partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Our general partner, or any transferee holding incentive distribution rights, may elect to cause us to issue common units and general partner units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of our conflicts committee or the holders of our common units. This could result in lower distributions to holders of our common units.

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received distributions on its incentive distribution rights at the highest level to which it is entitled (48 percent, in addition to distributions paid on its two percent general partner interest, each as of December 31, 2016) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units and general partner units. The number of common units to be issued to our general partner will be equal to that number of common units that would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. Our general partner will also be issued the number of general partner units necessary to maintain our general partner's interest in us at the level that existed immediately prior to the reset election. We anticipate that our general partner would exercise this reset right to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive distributions based on the initial target distribution levels. This risk could be elevated if our incentive distribution rights have been transferred to a third party. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of distributions that they would have otherwise received had we not issued new common units and general partner units in connection with resetting the target distribution levels. Additionally, our general partner has the right to transfer all or any portion of our incentive distribution rights at any time, and such transferee shall have the same rights as the general partner relative to resetting target distributions if our general partner concurs that the tests for resetting target distributions have been fulfilled.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

We list our common units on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

LOGISTICS AND STORAGE

Crude Oil Pipeline Systems

The following table sets forth certain information regarding our crude oil pipeline systems as of December 31, 2016, each of which has an associated transportation services agreement with MPC (other than the inactive pipelines):

System name	Diameter (inches)	Length (miles)	Capacity (mbpd)[(1)]	Associated MPC refineries
Patoka to Lima crude system				
Patoka, IL to Lima, OH	20”/22”	304	267	Detroit, MI; Canton, OH
Catlettsburg and Robinson crude system				
Patoka, IL to Robinson, IL	20”	78	245	Robinson, IL
Patoka, IL to Catlettsburg, KY	24”/20”	406	270	Catlettsburg, KY
Subtotal		484	515	
Detroit crude system				
Samaria, MI to Detroit, MI	16”	44	117	Detroit, MI
Romulus, MI to Detroit, MI[(2)]	16”	17	80	Detroit, MI
Subtotal		61	197	
Wood River to Patoka crude system				
Wood River, IL to Patoka, IL	22”	57	215	All Midwest refineries
Roxanna, IL to Patoka, IL[(3)]	12”	58	99	All Midwest refineries
Subtotal		115	314	
Inactive pipelines		44	N/A	
Total crude oil pipelines		1,008	1,293	

(1) Capacity shown is 100 percent of the capacity of these pipeline systems and based on physical barrels.
(2) Includes approximately 16 miles of pipeline leased from a third party.
(3) This pipeline is leased from a third party.

Our crude oil pipeline systems and related assets are strategically positioned to support diverse and flexible crude oil supply options for MPC’s Midwest refineries, which receive imported and domestic crude oil through a variety of sources. Imported and domestic crude oil is transported to supply hubs in Wood River and Patoka, Illinois from a variety of regions, including: Cushing, Oklahoma on the Ozark pipeline system; Western Canada, Wyoming and North Dakota on the Keystone, Platte, Mustang and Enbridge pipeline systems; and the Gulf Coast on the Capline crude oil pipeline system. Our major crude oil pipeline systems are connected to these supply hubs and transport crude oil to refineries owned by MPC and third parties.

Product Pipeline Systems

The following table sets forth certain information regarding our product pipeline systems as of December 31, 2016, each of which has an associated transportation services agreement with MPC (other than our Louisville airport products system, which currently transports only third-party volumes, and the inactive pipelines):

System name	Diameter (inches)	Length (miles)	Capacity (mbpd)[1]	Associated MPC refineries
Cornerstone products system				
Cornerstone to East Sparta, OH	16”	50	198	Canton, OH
East Sparta, OH to Canton, OH	8”	8	40	Canton, OH
Subtotal		58	238	
Garyville products system				
Garyville, LA to Zachary, LA	20”	70	389	Garyville, LA
Zachary, LA to connecting pipelines[2]	36”	2	—	Garyville, LA
Subtotal		72	389	
Texas City products system				
Texas City, TX to Pasadena, TX	16”	39	215	Texas City, TX; Galveston Bay, TX
Pasadena, TX to connecting pipelines[2]	36”/30”	3	—	Texas City, TX; Galveston Bay, TX
Subtotal		42	215	
ORPL products system				
Kenova, WV to Columbus, OH	14”	150	68	Catlettsburg, KY
Canton, OH to East Sparta, OH[3,4]	6”	17	73	Canton, OH
East Sparta, OH to Heath, OH[4]	8”	81	29	Canton, OH
East Sparta, OH to Midland, PA[4]	8”	62	32	Canton, OH
Heath, OH to Dayton, OH	6”	108	24	Catlettsburg, KY; Canton, OH
Heath, OH to Findlay, OH	10”/8”	100	18	Catlettsburg, KY; Canton, OH
Subtotal		518	244	
Robinson products system				
Robinson, IL to Lima, OH	10”	250	51	Robinson, IL
Robinson, IL to Louisville, KY[5]	16”	129	82	Robinson, IL
Robinson, IL to Mt. Vernon, IN[6]	10”	79	77	Robinson, IL
Wood River, IL to Clermont, IN	10”	317	48	Robinson, IL
Wabash Pipeline System:				
West leg—Wood River, IL to Champaign, IL	12”	130	71	Robinson, IL
East leg—Robinson, IL to Champaign, IL	12”	86	99	Robinson, IL
Champaign, IL to Hammond, IN[7]	16”/12”	140	85	Robinson, IL
Subtotal		1,131	513	
Louisville airport products system				
Louisville, KY to Louisville International Airport	8”/6”	14	29	Robinson, IL
Inactive pipelines[8]		123	N/A	
Total product pipelines		1,958	1,628	

(1) Capacity shown is 100 percent of the capacity of these pipeline systems.

(2) Capacity not shown, as the pipeline is designed to meet outgoing capacity for connecting third-party pipelines.
(3) Consists of two separate approximately 8.5-mile pipelines.
(4) This pipeline is bi-directional.
(5) Drag-reducing agent for this pipeline is currently not active and can be reactivated at any time resulting in a capacity increase of 10 mbpd.
(6) This pipeline is leased from a third party.
(7) Capacity not shown for 16 miles on this system due to complexities associated with bi-directional capability.
(8) Includes 77 miles of pipeline leased from a third party.

Our product pipeline systems are strategically positioned to transport products from six of MPC's refineries to MPC's marketing operations, as well as those of third parties. These pipeline systems also supply feedstocks to MPC's Midwest refineries. These product pipeline systems are integrated with MPC's expansive network of refined product marketing terminals, which support MPC's integrated midstream business.

Marine Assets

The following table sets forth certain information regarding our marine assets as of December 31, 2016. The marine business currently has an associated transportation service agreement with MPC.

Asset name	Quantity	Associated MPC refineries
Barges	204	Catlettsburg, KY; Garyville, LA
Towboats	18	Catlettsburg, KY; Garyville, LA
Marine Repair Facility	N/A	Catlettsburg, KY

Our fleet of boats and barges transport light products, heavy oils, crude oil, renewable fuels, chemicals and feedstocks to and from refineries and terminals owned by MPC in the Midwest and U.S. Gulf Coast regions. The MRF is a full-service marine shipyard located on the Ohio River, adjacent to MPC's Catlettsburg, Kentucky refinery. The MRF is responsible for the preventive routine and unplanned maintenance of towing vessels, barges and local terminal facilities.

Other L&S Assets

The following table sets forth certain information regarding our other midstream assets as of December 31, 2016, each of which currently has an associated transportation services agreement or storage services agreement with MPC:

Asset name	Capacity(1)	Associated MPC refineries
Wood River Barge Dock	78 mbpd	Garyville, LA
Neal Butane Cavern	1,000 mbbls	Catlettsburg, KY
Patoka Tank Farm	2,626 mbbls	All Midwest refineries
Wood River Tank Farm	419 mbbls	All Midwest refineries
Martinsville Tank Farm	738 mbbls	Detroit, MI; Canton, OH
Lebanon Tank Farm	750 mbbls	Detroit, MI; Canton, OH
Hartford Tank Farm(2)	430 mbbls	All Midwest refineries

(1) All capacity shown is for 100 percent of the available storage capacity of our butane cavern and tank farms and 100 percent of the barge dock's average capacity.
(2) MPLX LP leases the Hartford Tank Farm from Wood River Pipe Lines LLC and Buckeye Terminals, LLC.

GATHERING AND PROCESSING

The following tables set forth certain information relating to our gas processing facilities, fractionation facilities, natural gas gathering systems, NGL pipelines, natural gas pipeline and crude oil and refined product pipelines as of and for the year ended December 31, 2016. All throughputs and utilizations included are weighted-averages for days in operation.

Gas Processing Complexes

Plant	Location	Design Throughput Capacity (mmcf/d)	Natural Gas Throughput[(1)] (mmcf/d)	Utilization of Design Capacity[(1)]
Marcellus Shale:				
Keystone Complex	Butler County, PA	410	265	65%
Houston Complex[(5)]	Washington County, PA	555	446	80%
Majorsville Complex	Marshall County, WV	1,070	789	74%
Mobley Complex	Wetzel County, WV	920	690	80%
Sherwood Complex	Doddridge County, WV	1,200	1,020	85%
Total Marcellus Shale		4,155	3,210	78%
Utica Shale:				
Cadiz Complex	Harrison County, OH	525	477	91%
Seneca Complex	Noble County, OH	800	595	74%
Total Utica Shale		1,325	1,072	81%
Southern Appalachia:				
Kenova Complex[(2)]	Wayne County, WV	160	102	64%
Boldman Complex[(2)]	Pike County, KY	70	30	43%
Cobb Complex	Kanawha County, WV	65	22	34%
Kermit Complex[(2)(3)]	Mingo County, WV	32	N/A	N/A
Langley Complex	Langley, KY	325	99	30%
Total Southern Appalachia[(3)]		620	253	41%
Southwest:				
Carthage Complex	Panola County, TX	600	493	82%
Western Oklahoma Complex	Custer and Beckham Counties, OK	425	333	78%
Hidalgo Complex	Culberson County, TX	200	105	81%
Javelina Complex	Corpus Christi, TX	142	99	70%
Total Southwest[(4)]		1,367	1,030	79%
Total Gas Processing		7,467	5,565	76%

(1) Natural gas throughput is a weighted average for days in operation. The utilization of design capacity has been calculated using the weighted average design throughput capacity.

(2) A portion of the gas processed at the Boldman plant, and all of the gas processed at the Kermit plant, is further processed at the Kenova plant to recover additional NGLs.

(3) The Kermit processing plant is operated by a third party solely to prevent liquids from condensing in the gathering and transmission pipelines upstream of our Kenova plant. We do not receive Kermit gas volume information but do receive all of the liquids produced at the Kermit Complex. As such, the design capacity has been excluded from the subtotal.

(4) Centrahoma processing capacity of 300 mmcf/d and actual throughput of 196 mmcf/d, that exceeded our capacity of 120 mmcf/d, are not included in this table as we own a non-operating interest.

(5) Approximately 35 mmcf/d of processing capacity at the Houston Complex will be decommissioned during the first quarter of 2017 and replaced with 200 mmcf/d of processing capacity.

Fractionation & Condensate Stabilization Facilities

Facility	Location	Design Throughput Capacity (mbpd)	NGL Throughput (mbpd)	Utilization of Design Capacity
Marcellus Shale:				
Keystone Complex[1][2]	Butler County, PA	47	14	30%
Houston Complex[1]	Washington County, PA	60	60	100%
Total Marcellus Shale		107	74	69%
Hopedale Complex[1][3]	Harrison County, OH	120	110	92%
Utica Shale:				
Ohio Condensate Complex[4]	Harrison County, OH	23	14	61%
Total Utica Shale		23	14	61%
Southern Appalachia:				
Siloam Complex[5]	South Shore, KY	24	15	63%
Total Southern Appalachia		24	15	63%
Southwest:				
Javelina Complex	Corpus Christi, TX	11	7	64%
Total Southwest		11	7	64%
Total C3+ Fractionation and Condensate Stabilization		285	220	77%

(1) Our Houston, Hopedale and Keystone Complexes have above-ground NGL storage with a usable capacity of 28 million gallons, large-scale truck and rail loading. In addition, our Houston Complex has large-scale truck unloading. We also have access to up to an additional 50 million gallons of propane storage capacity that can be utilized by our assets in the Marcellus Shale, Utica Shale, and Appalachia region under an agreement with a third party that expires in 2018. Lastly, we have up to 9 million gallons of butane storage and 8 million gallons of propane storage with third parties that can be utilized by our assets in the Marcellus Shale and Utica Shale.

(2) Includes 33 mbpd of de-propanization only capacity.

(3) Our Hopedale Complex is jointly owned by Ohio Fractionation and MarkWest Utica EMG. Ohio Fractionation is a subsidiary of MarkWest Liberty Midstream. MarkWest Liberty Midstream and MarkWest Utica EMG are entities that operate in the Marcellus and Utica regions, respectively. We account for MarkWest Utica EMG as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.

(4) The Ohio Condensate Complex has up to 7 million gallons of condensate storage. The Ohio Condensate Complex is partially-owned by MarkWest Utica EMG Condensate, L.L.C. We account for Ohio Condensate as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.

(5) Our Siloam Complex has both above-ground, pressurized NGL storage facilities, with usable capacity of two million gallons, and underground storage facilities, with usable capacity of 10 million gallons. Product can be received by truck, pipeline or rail and can be transported from the facility by truck, rail or barge. This facility has large-scale truck and rail loading and unloading capabilities, and a river barge facility capable of loading barges up to 860,000 gallons.

De-ethanization Facilities

Facility	Location	Design Throughput Capacity (mbpd)	NGL Throughput[1] (mbpd)	Utilization of Design Capacity[1]
Marcellus Shale:				
Keystone Complex	Butler County, PA	14	11	79%
Houston Complex	Washington County, PA	40	37	93%
Majorsville Complex	Marshall County, WV	40	42	105%
Mobley Complex	Wetzel County, WV	10	6	82%
Sherwood Complex	Doddridge County, WV	40	18	45%
Total Marcellus Shale		144	114	80%
Utica Shale:				
Cadiz Complex	Harrison County, OH	40	4	10%
Total Utica Shale		40	4	10%
Southwest:				
Javelina Complex	Corpus Christi, TX	18	11	61%
Total Southwest		18	11	61%
Total De-ethanization		202	129	64%

(1) NGL throughput is a weighted average for days in operation. The utilization of design capacity has been calculated using the weighted average design throughput capacity.

Natural Gas Gathering Systems

System	Location	Design Throughput Capacity (mmcf/d)	Natural Gas Throughput[1] (mmcf/d)	Utilization of Design Capacity[1]
Marcellus Shale:				
Keystone System	Butler County, PA	227	194	85%
Houston System	Washington County, PA	984	716	74%
Total Marcellus Shale		1,211	910	77%
Utica Shale:				
Ohio Gathering System[2]	Harrison, Monroe, Belmont, Guernsey and Noble Counties, OH	1,393	867	63%
Jefferson Gas System[3]	Jefferson County, OH	250	65	26%
Total Utica Shale		1,643	932	58%
Southwest				
East Texas System	Harrison and Panola Counties, TX	680	578	85%
Western Oklahoma System	Wheeler County, TX and Roger Mills, Ellis, Custer, Beckham and Washita Counties, OK	585	364	62%
Southeast Oklahoma System	Hughes, Pittsburg and Coal Counties, OK	1,205	449	37%
Eagle Ford System	Dimmit County, TX	45	31	69%
Other Systems[4]	Various	70	11	16%
Total Southwest		2,585	1,433	55%
Total Natural Gas Gathering		5,439	3,275	61%

(1) Natural gas throughput is a weighted average for days in operation. The utilization of design capacity has been calculated using the weighted average design throughput capacity.

(2) The Ohio Gathering System is owned by Ohio Gathering. We account for Ohio Gathering as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.

(3) The Jefferson Gas System is owned by Jefferson Dry Gas, which is a consolidated joint venture between MarkWest Liberty Midstream and EMG MWE Dry Gas Holdings, LLC. We account for Jefferson Dry Gas as an equity method investment.

(4) Excludes lateral pipelines where revenue is not based on throughput.

NGL Pipelines

Pipeline	Location	Design Throughput Capacity (mbpd)	NGL Throughput (mbpd)	Utilization of Design Capacity
Marcellus Shale:				
Sherwood to Mobley propane and heavier liquids pipeline	Doddridge County, WV to Wetzel County, WV	45	40	89%
Mobley to Majorsville propane and heavier liquids pipeline	Wetzel County, WV to Marshall County, WV	80	64	80%
Majorsville to Houston propane and heavier liquids pipeline	Marshall County, WV to Washington County, PA	47	34	72%
Majorsville to Hopedale propane and heavier liquids pipeline	Marshall County, WV to Harrison County, OH	90	72	80%
Third-party processing plant to Keystone ethane and heavier liquids pipeline	Butler County, PA	32	7	22%
Keystone to Mariner West ethane pipeline(1)	Butler County, PA to Beaver County, PA	35	12	34%
Houston to Ohio River ethane pipeline(2)	Washington County, PA to Beaver County, PA	57	16	28%
Majorsville to Houston ethane pipeline(1)	Marshall County, WV to Washington County, PA	60	66	110%
Sherwood to Mobley ethane pipeline	Doddridge County, WV to Wetzel County, WV	27	18	67%
Mobley to Fort Beeler ethane pipeline	Wetzel County, WV to Marshall County, WV	64	24	38%
Fort Beeler to Majorsville ethane pipeline	Marshall County, WV	45	24	53%
Utica Shale:				
Seneca to Cadiz liquids pipeline	Noble County, OH to Harrison County, OH	90	20	22%
Cadiz to Hopedale liquids pipeline	Harrison County, OH	90	38	42%
Appalachia:				
Langley to Siloam liquids pipeline(3)	Langley, KY to South Shore, KY	17	12	71%
Southwest:				
East Texas liquids pipeline	Panola County, TX	39	27	69%

(1) This pipeline is FERC-regulated.

(2) This is a section of the Mariner West pipeline, which is FERC-regulated and is leased to and operated by Sunoco.

(3) NGLs transported through the Langley to Ranger and Ranger to Kenova pipelines are combined with NGLs recovered at the Kenova Complex. The design capacity and volume reported for the Langley to Siloam pipeline represent the combined NGL stream.

Crude Oil Pipeline

We also have a crude oil pipeline constructed in 1973 that runs from Manistee County, Michigan to Crawford County, Michigan. The design capacity throughput for this pipeline is 60 mbpd. For the year ended December 31, 2016, NGL throughput on this pipeline was 9 mbpd, which was approximately 15 percent utilization.

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property and in some instance these rights-of-way are revocable at the election of the grantor. In many instances, lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where determined necessary, permits, leases, license agreements and franchise ordinances from public authorities to cross over or under, or to lay facilities in or along water courses, county roads, municipal streets and state highways, as applicable, and in some instances, these permits are revocable at the election of the grantor. We also have obtained easements and license agreements from railroad companies to cross over or under railroad properties or rights-of-way, many of which are also revocable at the election of the grantor. We believe that our properties and facilities are adequate for our operations and that our facilities are adequately maintained. Many of our compression, processing, fractionation and other facilities, including our Siloam, Houston and Hopedale fractionation plants, and certain of our pipelines and other facilities, are on land that we either own in fee or that is held under long-term leases, but for any such facilities that are on land that we lease, including our Majorsville, Sarsen, Keystone, Boldman, Kermit and Cobb processing facilities, we could be required to remove our facilities upon the termination or expiration of the leases. In addition, our L&S segment leases vehicles, building spaces, and pipeline equipment under long-term operating leases, most of which include renewal options. Our L&S segment also leases certain pipelines under a capital lease that has a fixed price purchase option in 2020.

Some of the leases, easements, rights-of-way, permits, licenses and franchise ordinances that were transferred to us required the consent of the then-current landowner to transfer these rights, which in some instances was a governmental entity. We believe that we have obtained sufficient third-party consents, permits and authorizations for the transfer of the assets necessary for us to operate our business. We also believe we have satisfactory title or other right to all of our material land assets. Title to these properties is subject to encumbrances in some cases; however, we believe that none of these burdens will materially detract from the value of these properties or from our interest in these properties, or will materially interfere with their use in the operation of our business. See Item 8. Financial Statements and Supplementary Data—Note 21, for additional information regarding our leases.

Under the omnibus agreement, MPC indemnifies us for certain title defects and for failures to obtain certain consents and permits necessary to conduct our business with respect to the assets contributed to us by MPC in connection with our Initial Offering. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, liens that can be imposed in some jurisdictions for government-initiated action to clean up environmental contamination, liens for current taxes and other burdens, and easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by our Predecessor (as defined below) or us, we believe that none of these burdens should materially detract from the value of these properties or from our interest in these properties or should materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings

We are the subject of, or a party to, a number of pending or threatened legal actions, contingencies and commitments involving a variety of matters, including laws and regulations relating to the environment. Some of these matters are discussed below.

Litigation

We are a party to a number of lawsuits and other proceedings and cannot predict the outcome of every such matter with certainty. While it is possible that an adverse result in one or more of the lawsuits or proceedings in which we are a defendant could be material to us, based upon current information and our experience as a defendant in other matters, we believe that these lawsuits and proceedings, individually or in the aggregate, will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

In 2003, the State of Illinois brought an action against the Premcor Refining Group, Inc. (“Premcor”) and Apex Refining Company (“Apex”) asserting claims for environmental cleanup related to the refinery owned by these entities in the Hartford/Wood River, Illinois area. In 2006, Premcor and Apex filed third-party complaints against numerous owners and operators of petroleum products facilities in the Hartford/Wood River, Illinois area, including MPL. These complaints, which have been amended since filing, assert claims of common law nuisance and contribution under the Illinois Contribution Act and other laws for environmental cleanup costs that may be imposed on Premcor and Apex by the State of Illinois. On September 6, 2016, the trial court approved a settlement between Apex and the State of Illinois whereby Apex agreed to settle all claims against it for a $10 million payment. Premcor has objected to this ruling and is seeking an appeal. There are several third-party defendants in the litigation and MPL has asserted cross-claims in contribution against the various third-party defendants. This litigation is currently pending in the Third Judicial Circuit Court, Madison County, Illinois. While the ultimate outcome of these litigated matters remains uncertain, neither the likelihood of an unfavorable outcome nor the ultimate liability, if any, with respect to this matter can be determined at this time and the Partnership is unable to estimate a reasonably possible loss (or range of loss) for this litigation. Under the omnibus agreement, MPC will indemnify the Partnership for the full cost of any losses should MPL be deemed responsible for any damages in this lawsuit.

Environmental Proceedings

The Illinois Environmental Protection Agency ("IEPA") initiated an enforcement action against MPL, in connection with an April 17, 2016 pipeline release to the Wabash River near Crawleyville, Indiana. MPL responded to a Clean Water Act request for information from the EPA in furtherance of its investigation of possible violations arising from the April 17, 2016 pipeline release. The IEPA and the EPA may each seek penalties in connection with this matter. The IEPA and the EPA may each seek
penalties in excess of $100,000 in connection with this matter.

On February 17, 2016, MarkWest Liberty Bluestone, L.L.C. ("MarkWest Liberty Bluestone"), received an initial Consent Agreement and Final Order ("Initial CAFO") from the EPA alleging violations of the Clean Air Act resulting from an EPA compliance inspection conducted in July 2012 at our Sarsen Facility, a gas processing facility at our Keystone Complex located in Pennsylvania. The alleged violations included the failure to comply with monitoring, tagging, recordkeeping and repair requirements with respect to certain pumps and/or valves at the facility and with certain emissions reduction and permit application requirements. The Initial CAFO set forth a proposed penalty of $285,000. After subsequent negotiations, MarkWest Liberty Bluestone has agreed in principle to a Consent Agreement and Final Order resolving these issues, pursuant to which MarkWest Liberty Bluestone would pay a penalty of $95,000 and implement certain enhancements in connection with its existing leak monitoring program.

MarkWest Liberty Midstream, MarkWest Ohio Fractionation Company, L.L.C. ("Ohio Fractionation") and MarkWest Utica EMG are in settlement discussions with the EPA relating to certain notices of violation alleging claims regarding fugitive emissions and violations of the Clean Air Act at our Hopedale Complex, a fractionation facility located in Ohio (issued October 7, 2015 and June 27, 2016), our Houston Complex, a gas processing facility located in Pennsylvania (issued April 5, 2016) and our Seneca Complex, a gas processing facility located in Ohio (issued September 9, 2016). In connection with a proposed global settlement which would cover nineteen gas processing and fractionation sites, MarkWest Liberty Midstream, Ohio Fractionation and MarkWest Utica EMG, together with other MarkWest affiliates, have agreed in principle to pay a penalty of approximately $0.9 million, undertake certain monitoring and emission reduction projects at certain facilities with an estimated cost of approximately $3.3 million, and implement certain process enhancements for its and its affiliates' leak detection and repair programs at the nineteen gas processing and fractionation sites.

In July 2015, representatives from the EPA and the United States Department of Justice conducted a raid on a MarkWest Liberty Midstream pipeline launcher/receiver site utilized for pipeline maintenance operations in Washington County, Pennsylvania pursuant to a search warrant issued by a magistrate of the United States District Court for the Western District of Pennsylvania. As part of this initiative, the U.S. Attorney's Office for the Western District of Pennsylvania proceeded with an investigation of MarkWest Liberty Midstream's launcher/receiver, pipeline and compressor station operations. In response to the investigation, MarkWest initiated independent studies which demonstrated that there was no risk to worker safety and no threat of public harm associated with MarkWest Liberty Midstream's launcher/receiver operations. These findings were supported by a subsequent inspection and review by the Occupational Safety and Health Administration. After providing these studies, and other substantial documentation related to MarkWest Liberty Midstream's pipeline and compressor stations, and arranging site visits and conducting several meetings with the government's representatives, on September 13, 2016, the U.S. Attorney's Office for the Western District of Pennsylvania rendered a declination decision, dropping its criminal investigation and declining to pursue charges in this matter.

MarkWest Liberty Midstream continues to discuss with the EPA and the State of Pennsylvania civil enforcement allegations associated with permitting or other related regulatory obligations for its launcher/receiver and compressor station facilities in the region. In connection with these discussions, MarkWest Liberty Midstream received an initial proposal from the EPA to settle all civil claims associated with this matter for the combination of a proposed cash penalty of approximately $2.4 million and proposed supplemental environmental projects with an estimated cost of approximately $3.6 million. MarkWest Liberty Midstream will be submitting a response asserting that this action involves novel issues surrounding primarily minor source emissions from facilities that the agencies themselves considered de minimis and were not subject to regulation and consequently that the settlement proposal is excessive. MarkWest will continue to negotiate with EPA regarding the amount and scope of the proposed settlement.

We are involved in a number of other environmental proceedings arising in the ordinary course of business. While the ultimate outcome and impact on us cannot be predicted with certainty, we believe the resolution of these environmental proceedings will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Item 4. Mine Safety Disclosures

Not applicable

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common limited partner units are listed on the NYSE and traded under the symbol "MPLX." As of February 13, 2017, there were 365 registered holders of 270,638,348 outstanding common units held by the public, including 267,225,173 common units held in street name. In addition, as of February 13, 2017, MPC and its affiliates owned 86,619,313 of our common units, and 7,372,419 of our general partner units, which together constitutes a 25.5 percent ownership interest (including the Class B units on an as-converted basis).

The following table reflects intraday high and low sales prices of and cash distributions declared on our common units by quarter over the last two fiscal years.

Quarter ended	Trading prices per common unit High	Trading prices per common unit Low	Quarterly cash distribution per unit[(1)]	Distribution date	Record date
December 31, 2016	$35.32	$30.09	$0.5200	February 14, 2017	February 6, 2017
September 30, 2016	35.12	30.36	0.5150	November 14, 2016	November 4, 2016
June 30, 2016	34.92	26.75	0.5100	August 12, 2016	August 2, 2016
March 31, 2016	39.46	16.34	0.5050	May 13, 2016	May 3, 2016
December 31, 2015	45.63	26.38	0.5000	February 12, 2016	February 4, 2016
September 30, 2015	71.73	35.55	0.4700	November 13, 2015	November 3, 2015
June 30, 2015	80.00	70.23	0.4400	August 14, 2015	August 4, 2015
March 31, 2015	85.57	65.29	0.4100	May 15, 2015	May 5, 2015

(1) Represents cash distributions attributable to the quarter and declared and paid in accordance with our partnership agreement.

We intend to pay a minimum quarterly distribution of $0.2625 per unit. Although our partnership agreement requires that we distribute all of our available cash each quarter, we do not have a legal obligation to distribute any particular amount per common unit.

Distributions of Available Cash

Our partnership agreement requires that, within 60 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date. Class B unitholders do not receive cash distributions.

Definition of available cash. Available cash is defined in our partnership agreement. Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by our general partner to:
    - provide for the proper conduct of our business (including reserves for our future capital expenditures, anticipated future debt service requirements and refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceedings or rate proceedings under applicable law subsequent to that quarter);
    - comply with applicable law, any of our debt instruments or other agreements; or
    - provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);

- plus, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

Intent to Distribute the Minimum Quarterly Distribution. Under our current cash distribution policy, we intend to make a minimum quarterly distribution to the holders of our common units and subordinated units of $0.2625 per unit, or $1.05 per unit on an annualized basis, to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. The amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Debt and Liquidity Overview, for a discussion of the restrictions included in our bank revolving credit facility that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights. Our general partner is currently entitled to two percent of all quarterly distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's two percent interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its two percent general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 48 percent, of the cash we distribute from operating surplus in excess of $0.301875 per unit per quarter. The maximum distribution of 48 percent does not include any distributions that our general partner or its affiliates may receive on common, subordinated or general partner units that they own.

Percentage Allocations of Available Cash. The following table illustrates the percentage allocations of available cash from operating surplus between the common unitholders and our general partner based on the specified target distribution levels. The amounts set forth under "Marginal percentage interest in distributions" are the percentage interests of our general partner and the common unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total quarterly distribution per unit target amount." The percentage interests shown for our common unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its two percent general partner interest and assume that our general partner has contributed any additional capital necessary to maintain its two percent general partner interest, that our general partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

	Total quarterly distribution per unit target amount		Marginal percentage interest in distributions	
			Unitholders[(1)]	General Partner
Minimum Quarterly Distribution	$0.2625		98.0%	2.0%
First Target Distribution	above $0.2625	up to $0.301875	98.0%	2.0%
Second Target Distribution	above $0.301875	up to $0.328125	85.0%	15.0%
Third Target Distribution	above $0.328125	up to $0.393750	75.0%	25.0%
Thereafter	above $0.393750		50.0%	50.0%

(1) The unitholders' percentage of distributions is paid to common unitholders and subordinated unitholders, if any.

Preferred Unit Distributions

The holders of the Preferred units are entitled to receive cumulative quarterly distributions equal to $0.528125 per unit for any quarter ending on or before May 13, 2018, and thereafter the quarterly distributions on each Preferred unit will equal the greater of $0.528125 per unit or the amount that each Preferred unit would have otherwise received if it had been converted into common units at the then-applicable Preferred unit conversion rate. The Partnership may not pay any distributions for any quarter on any junior securities, including any of the common units, the Class B units and the incentive distribution rights, unless the distribution payable to the Preferred units with respect to such quarter, together with any previously accrued and unpaid distributions to the Preferred units, have been paid in full.

Item 6. Selected Financial Data

The following table shows selected historical consolidated financial data of MPLX LP as of the dates and for the years indicated. On May 1, 2013, we acquired a five percent interest in Pipe Line Holdings, resulting in a 56 percent indirect ownership interest at December 31, 2013. We then acquired a 13 percent interest in Pipe Line Holdings on March 1, 2014, and a 30.5 percent interest on December 1, 2014, resulting in a 99.5 percent indirect ownership interest at December 31, 2014. The remaining 0.5 percent interest was purchased on December 4, 2015. On this same date, a wholly-owned subsidiary of MPLX LP merged with MarkWest. The information in Items 6, 7 and 8 includes periods prior to the acquisition of HSM by MPLX LP, which occurred on March 31, 2016. Consequently, the Partnership's consolidated financial statements have been retrospectively recast for all periods presented to include the historical results of HSM, as required for transactions between entities under common control. See Item 8. Financial Statements and Supplementary Data—Note 4 and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for more information on the MarkWest Merger and acquisition of HSM.

The following table also presents the non-GAAP financial measures of Adjusted EBITDA and DCF, which we use in our business. For the definitions of Adjusted EBITDA and DCF and a reconciliation to our most directly comparable financial measures calculated and presented in accordance with GAAP, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Information and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations.

(In millions, except per unit data)	2016	2015	2014	2013	2012
Consolidated Statements of Income Data					
Total revenues and other income	$ 2,590	$ 961	$ 793	$ 713	$ 686
Income from operations	507	298	245	213	204
Net income	258	249	239	211	204
Net income attributable to MPLX LP	233	156	121	78	13
Limited partners' interest in net income attributable to MPLX LP	1	99	115	76	13
Per Unit Data					
Net income attributable to MPLX LP per limited partner unit (basic and diluted):					
Common—basic	$ —	$ 1.23	$ 1.55	$ 1.05	$ 0.18
Common—diluted	—	1.22	1.55	1.05	0.18
Subordinated—basic and diluted	—	0.11	1.50	1.01	0.17
Cash distributions declared per limited partner common unit	$2.0500	$1.8200	$1.4100	$1.1675	$0.1769
Consolidated Balance Sheets Data (at period end)					
Property, plant and equipment, net	$10,730	$ 9,997	$ 1,324	$ 1,248	$ 1,167
Total assets	16,646	16,104	1,544	1,504	1,572
Long-term debt, including capital leases(3)	4,422	5,255	644	10	10
Redeemable preferred units	1,000	—	—	—	—
Consolidated Statements of Cash Flows Data					
Net cash provided by (used in):					
Operating activities	$ 1,288	$ 340	$ 334	$ 297	$ 273
Investing activities	(1,212)	(1,599)	(137)	(158)	64
Financing activities	115	1,275	(224)	(302)	(120)
Additions to property, plant and equipment(1)	1,206	288	141	151	159
Other Financial Data					
Adjusted EBITDA attributable to MPLX LP(2)	$ 1,419	$ 498	$ 166	$ 111	$ 18
DCF(2)	1,140	399	137	114	17

(1) Represents cash capital expenditures as reflected on Consolidated Statements of Cash Flows for the periods indicated, which are included in cash used in investing activities.

(2) The 2012 Adjusted EBITDA attributable to MPLX LP is subsequent to the Initial Offering. The 2015 Adjusted EBITDA attributable to MPLX LP includes pre-merger EBITDA from MarkWest and the 2015 DCF includes undistributed DCF from MarkWest. For a discussion of the non-GAAP financial measures of Adjusted EBITDA and DCF and a reconciliation of Adjusted EBITDA and DCF to our most directly comparable measures calculated and presented in accordance with GAAP, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Information and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations.

(3) Includes amounts due within one year. During 2015, in connection with the MarkWest Merger, MPLX LP assumed MarkWest senior notes with an aggregate principal amount of $4.1 billion and used its credit facility to repay $850 million of the $943 million of borrowings under MarkWest's credit facility.

Operating Data

	2016	2015	2014	2013	2012
L&S					
Crude oil transported for (mbpd)[1]:					
MPC	906	864	838	853	830
Third parties	182	197	203	222	202
Total	1,088	1,061	1,041	1,075	1,032
% MPC	83%	81%	80%	79%	80%
Products transported for (mbpd)[2]:					
MPC[3]	763	887	852	862	909
Third parties	145	27	26	49	71
Total	908	914	878	911	980
% MPC	84%	97%	97%	95%	93%
Average tariff rates ($ per barrel):					
Crude oil pipelines	0.67	0.66	0.64	0.60	0.57
Product pipelines	0.69	0.65	0.61	0.56	0.51
Total pipelines	0.68	0.65	0.63	0.58	0.54
Barges[4]	204	205	199	184	177
Towboats[4]	18	18	18	17	15
G&P[5]					
Gathering Throughput (mmcf/d)					
Marcellus Operations	910	889			
Utica Operations[6][7]	932	745			
Southwest Operations[8]	1,433	1,441			
Total gathering throughput	3,275	3,075			
Natural Gas Processed (mmcf/d)					
Marcellus Operations	3,210	2,964			
Utica Operations[6]	1,072	1,136			
Southwest Operations	1,226	1,125			
Southern Appalachian Operations	253	243			
Total natural gas processed	5,761	5,468			
C2 + NGLs Fractionated (mbpd)					
Marcellus Operations[9][10]	260	220			
Utica Operations[6][10]	42	51			
Southwest Operations	18	24			
Southern Appalachian Operations[11]	15	12			
Total C2 + NGLs fractionated[12]	335	307			
Pricing Information					
Natural Gas NYMEX HH ($/MMBtu)	$ 2.55	$ 2.04			
C2 + NGL Pricing/gallon[13]	$ 0.47	$ 0.40			

(1) Represents the average aggregate daily number of barrels of crude oil transported on our pipeline systems and at our Wood River barge dock for MPC and for third parties. Volumes shown are 100 percent of the volumes transported on the pipeline systems and barge dock. Volumes shown for all periods exclude volumes transported on two undivided joint interest crude oil pipeline systems not contributed to MPLX LP at the Initial Offering.

(2) Represents the average aggregate daily number of barrels of products transported on our pipeline systems for MPC and third parties. Volumes shown are 100 percent of the volumes transported on the pipeline systems.

(3) Includes volumes shipped by MPC on various pipelines under joint tariffs with third parties. For accounting purposes, revenue attributable to these volumes is classified as third-party revenue because we receive payment from those third parties with respect to volumes shipped under the joint tariffs; however, the volumes associated with this revenue are applied towards MPC's minimum quarterly volume commitments on the applicable pipelines because MPC is the shipper of record.

(4) Represents the number of owned barges and towboats at the end of the period presented.

(5) G&P volumes represent the volumes after the close of the MarkWest Merger. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Supplemental MD&A—G&P Pro Forma for full-year pro forma information.

(6) Utica is an unconsolidated equity method investment and is consolidated for segment purposes only.

(7) The Jefferson Gas System came online in December 2015. The volumes reported for 2015 are the average daily rate for the days of operation.

(8) Includes approximately 309 mmcf/d and 310 mmcf/d related to unconsolidated equity method investments, Wirth and MarkWest Pioneer for the years ended December 31, 2016 and 2015, respectively.

(9) The Sherwood de-ethanization complex came online in December 2015. The volumes reported for 2015 are the average daily rate for the days of operation.

(10) Hopedale is jointly owned by Ohio Fractionation and MarkWest Utica EMG. Ohio Fractionation is a subsidiary of MarkWest Liberty Midstream. MarkWest Liberty Midstream and MarkWest Utica EMG are entities that operate in the Marcellus and Utica regions, respectively. The Marcellus Operations includes its portion utilized of the jointly owned Hopedale Fractionation Complex. The Utica Operations includes Utica's portion utilized of the jointly owned Hopedale Fractionation Complex.

(11) Includes NGLs fractionated for the Marcellus and Utica Operations.

(12) Purity ethane makes up approximately 128 and 104 mbpd of total fractionated products for the years ended December 31, 2016 and 2015, respectively.

(13) C2 + NGL pricing based on Mont Belvieu prices assuming an NGL barrel of approximately 35 percent ethane, 35 percent propane, six percent Iso-Butane, 12 percent normal butane and 12 percent natural gasoline.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information included under Item 1. Business, Item 1A. Risk Factors, Item 6. Selected Financial Data and Item 8. Financial Statements and Supplementary Data.

Management's Discussion and Analysis of Financial Condition and Results of Operations includes various forward-looking statements concerning trends or events potentially affecting our business. You can identify our forward-looking statements by words such as "anticipate," "believe," "estimate," "objective," "expect," "forecast," "goal," "intend," "plan," "predict," "project," "potential," "seek," "target," "could," "may," "should," "would," "will" or other similar expressions that convey the uncertainty of future events or outcomes. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements.

PARTNERSHIP OVERVIEW

We are a diversified, growth-oriented MLP formed by MPC to own, operate, develop and acquire midstream energy infrastructure assets. We are engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs; and the gathering, transportation and storage of crude oil and refined petroleum products.

SIGNIFICANT FINANCIAL AND OTHER HIGHLIGHTS

We have completed a full year of operations following the Partnership's strategic merger with MarkWest. Given the challenging economic and commodity environment, our priorities during 2016 included delivering solid financial results, carefully managing our capital and expenses, improving our financial leverage metrics and positioning the Partnership for longer term growth. Significant financial and other highlights for the year ended December 31, 2016 are listed below. Refer to Results of Operations and Liquidity and Capital Resources for further details.

- L&S segment operating income attributable to MPLX LP increased approximately $131 million, or 41 percent, in 2016 compared to 2015. This increase was primarily due to the acquisition of the inland marine business on March 31, 2016, which continues the diversification of earnings streams and adds additional fee-based revenues to the Partnership. The L&S segment operating income also increased due to higher average pipeline tariffs. See Item 8. Financial Statements and Supplementary Data—Note 4 for further details of the HSM acquisition.
- G&P segment operating income attributable to MPLX LP increased approximately $1.1 billion, or 1,389 percent, in 2016 compared to 2015, due to the MarkWest Merger. Despite declines in drilling activity by producers, the G&P segment realized volume increases across most of its businesses during 2016. Compared to full-year 2015, gathering volumes were up 11 percent, processing volumes were up 13 percent and fractionated volumes were up 25 percent.
- Net income for the year ended December 31, 2016 was $258 million, full-year 2016 DCF, a non-GAAP measure, was over $1.1 billion and full-year 2016 distributions were $2.05 per common unit, which represents a 13 percent increase over the full-year distributions of 2015.

During 2016, the Partnership substantially improved its financial leverage. This was accomplished through a balance of managing capital expenditures and costs and opportunistically accessing the capital markets, including:

- The private placement of approximately 30.8 million 6.5 percent Series A Convertible Preferred units for a cash purchase price of $32.50 per unit during the second quarter of 2016. The aggregate net proceeds of approximately $984 million from the sale of the Preferred units was used for capital expenditures and repayment of debt.

- The issuance of an aggregate of 26,347,887 common units under the ATM Program during the year ended December 31, 2016, generating net proceeds of approximately $776 million. As of December 31, 2016, $717 million of common units remains available for issuance through the ATM program under the Distribution Agreement.

During 2016, the Partnership also completed several significant organic growth projects, including:

- On October 11, 2016, the Cornerstone Pipeline became fully operational. This is a key organic growth project within our L&S segment designed to transport condensate and natural gasoline from the Marcellus and Utica regions to MPC's Canton, Ohio, refinery. The Partnership is expanding the capacity of existing pipelines and constructing new pipelines as part of a larger build-out of Utica Shale infrastructure, seizing a unique opportunity to connect natural gas liquids to downstream markets in the Midwest and Canada through our extensive distribution network.
- We expanded our presence in the Southwest with the completion of the Hidalgo gas processing complex in the Delaware Basin of Texas, and will evaluate further investments in gathering and processing to support the substantial activity our producer-customers are pursuing in the region.

Looking ahead, the Partnership is taking actions that should contribute to long-term value for our investors, including the following recent announcements made in 2017:

- Planned acquisition of assets from MPC with an estimated $1.4 billion of annual EBITDA, along with our intentions to reduce the Partnership's cost of capital by offering to exchange MPLX LP units for MPC's IDRs;
- Strategic joint venture with Antero Midstream to support Antero Resources in the Marcellus Shale; and
- Public debt offering of $2.25 billion principal amount senior notes.

Refer to Item 1. Business—Recent Developments and Liquidity and Capital Resources for further details concerning the above-listed announcements.

NON-GAAP FINANCIAL INFORMATION

Our management uses a variety of financial and operating metrics to analyze our performance. These metrics are significant factors in assessing our operating results and profitability and include the non-GAAP financial measures of Adjusted EBITDA and DCF. The amount of Adjusted EBITDA and DCF generated is considered by the board of directors of our general partner in approving the Partnership's cash distribution.

We define Adjusted EBITDA as net income adjusted for (i) depreciation and amortization; (ii) provision (benefit) for income taxes; (iii) amortization of deferred financing costs; (iv) non-cash equity-based compensation; (v) impairment expense; (vi) net interest and other financial costs; (vii) loss (income) from equity investments; (viii) distributions from unconsolidated subsidiaries; (ix) unrealized derivative losses (gains); and (x) acquisition costs. We also use DCF, which we define as Adjusted EBITDA adjusted for (i) deferred revenue impacts; (ii) net interest and other financial costs; (iii) maintenance capital expenditures; and (iv) other non-cash items. The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record the realized gain or loss of the contract.

We believe that the presentation of Adjusted EBITDA and DCF provides useful information to investors in assessing our financial condition and results of operations. The GAAP measures most directly comparable to

Adjusted EBITDA and DCF are net income and net cash provided by operating activities. Adjusted EBITDA and DCF should not be considered as alternatives to GAAP net income or net cash provided by operating activities. Adjusted EBITDA and DCF have important limitations as analytical tools because they exclude some but not all items that affect net income and net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Adjusted EBITDA and DCF should not be considered in isolation or as substitutes for analysis of our results as reported under GAAP. Additionally, because Adjusted EBITDA and DCF may be defined differently by other companies in our industry, our definitions of Adjusted EBITDA and DCF may not be comparable to similarly titled measures of other companies, thereby diminishing their utility. For a reconciliation of Adjusted EBITDA and DCF to their most directly comparable measures calculated and presented in accordance with GAAP, see Results of Operations.

Management evaluates contract performance on the basis of net operating margin (a non-GAAP financial measure), which is defined as segment revenue less segment purchased product costs less realized derivative gain (loss). These charges have been excluded for the purpose of enhancing the understanding by both management and investors of the underlying baseline operating performance of our contractual arrangements, which management uses to evaluate our financial performance for purposes of planning and forecasting. Net operating margin does not have any standardized definition and, therefore, is unlikely to be comparable to similar measures presented by other reporting companies. Net operating margin results should not be evaluated in isolation of, or as a substitute for, our financial results prepared in accordance with GAAP. Our use of net operating margin and the underlying methodology in excluding certain charges is not necessarily an indication of the results of operations expected in the future, or that we will not, in fact, incur such charges in future periods.

In evaluating our financial performance, management utilizes the segment performance measures, segment revenues and segment operating income, including total segment operating income. The use of these measures allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. See Item 8. Financial Statements and Supplementary Data—Note 10 for the reconciliations of these segment measures, including total segment operating income, to their respective most directly comparable GAAP measures.

COMPARABILITY OF OUR FINANCIAL RESULTS

Our acquisitions and impairments have impacted comparability of our financial results (see Item 8. Financial Statements and Supplementary Data—Notes 4 and 18).

RESULTS OF OPERATIONS

The following table and discussion is a summary of our results of operations for the years ended 2016, 2015 and 2014, including a reconciliation of Adjusted EBITDA and DCF from net income and net cash provided by operating activities, the most directly comparable GAAP financial measures. Prior period financial information has been retrospectively adjusted for the acquisition of HSM.

(In millions)	2016	2015	$ Change	2014	$ Change
Revenues and other income:					
Service revenue	$ 958	$130	$ 828	$ 70	$ 60
Service revenue—related parties	603	593	10	662	(69)
Rental income	298	20	278	—	20
Rental income—related parties	114	101	13	15	86
Product sales	572	36	536	—	36
Product sales—related parties	11	1	10	—	1
Gain on sale of assets	1	—	1	—	—
(Loss) income from equity method investments	(74)	3	(77)	—	3
Other income	6	6	—	6	—
Other income—related parties	101	71	30	40	31
Total revenues and other income	2,590	961	1,629	793	168
Costs and expenses:					
Cost of revenues (excludes items below)	354	225	129	228	(3)
Purchased product costs	448	20	428	—	20
Rental cost of sales	53	5	48	1	4
Purchases—related parties	316	166	150	153	13
Depreciation and amortization	546	116	430	75	41
Impairment expense	130	—	130	—	—
General and administrative expenses	193	118	75	81	37
Other taxes	43	13	30	10	3
Total costs and expenses	2,083	663	1,420	548	115
Income from operations	507	298	209	245	53
Related party interest and other financial costs	1	—	1	—	—
Interest expense (net of amounts capitalized of $28 million, $5 million, and $1 million, respectively)	210	35	175	4	31
Other financial costs	50	13	37	1	12
Income before income taxes	246	250	(4)	240	10
(Benefit) provision for income taxes	(12)	1	(13)	1	—
Net income	258	249	9	239	10
Less: Net income attributable to noncontrolling interests	2	1	1	57	(56)
Less: Net income attributable to Predecessor	23	92	(69)	61	31
Net income attributable to MPLX LP	$ 233	$156	$ 77	$121	$ 35
Adjusted EBITDA attributable to MPLX LP[(1)]	$1,419	$498	$ 921	$166	$332
DCF[(1)]	$1,140	$399	$ 741	$137	$262
DCF attributable to GP and LP unitholders[(1)]	$1,099	$399	$ 700	$137	$262

(1) Non-GAAP financial measure. See the following tables for reconciliations to the most directly comparable GAAP measures.

(In millions)	2016	2015	2014
Reconciliation of Adjusted EBITDA attributable to MPLX LP and DCF attributable to GP and LP unitholders from Net income:			
Net income	$ 258	$ 249	$239
Depreciation and amortization	546	116	75
(Benefit) provision for income taxes	(12)	1	1
Amortization of deferred financing costs	46	5	—
Non-cash equity-based compensation	10	4	2
Impairment expense	130	—	—
Net interest and other financial costs	215	43	5
Loss (income) from equity investments	74	(3)	—
Distributions from unconsolidated subsidiaries	150	15	—
Unrealized derivative losses (gains)(1)	36	(4)	—
Acquisition costs	(1)	30	—
Adjusted EBITDA	1,452	456	322
Adjusted EBITDA attributable to noncontrolling interests	(3)	(1)	(69)
Adjusted EBITDA attributable to Predecessor(2)	(30)	(119)	(87)
MarkWest's pre-merger EBITDA(3)	—	162	—
Adjusted EBITDA attributable to MPLX LP	1,419	498	166
Deferred revenue impacts	8	6	(3)
Net interest and other financial costs	(215)	(36)	(6)
Maintenance capital expenditures	(68)	(31)	(22)
Other	(4)	(6)	2
DCF pre-MarkWest undistributed	1,140	431	137
MarkWest undistributed DCF(2)	—	(32)	—
DCF	1,140	399	137
Preferred unit distributions	(41)	—	—
DCF attributable to GP and LP unitholders	$1,099	$ 399	$137

(In millions)	2016	2015	2014
Reconciliation of Adjusted EBITDA attributable to MPLX LP and DCF attributable to GP and LP unitholders from Net cash provided by operating activities:			
Net cash provided by operating activities	$1,288	$ 340	$334
Changes in working capital items	(89)	54	(19)
All other, net	(20)	(12)	(2)
Non-cash equity-based compensation	10	4	2
Net gain on disposal of assets	1	—	—
Net interest and other financial costs	215	43	5
Current income taxes	5	—	—
Asset retirement expenditures	5	1	2
Unrealized derivative losses (gains)[(1)]	36	(4)	—
Acquisition costs	(1)	30	—
Other	2	—	—
Adjusted EBITDA	1,452	456	322
Adjusted EBITDA attributable to noncontrolling interests	(3)	(1)	(69)
Adjusted EBITDA attributable to Predecessor[(2)]	(30)	(119)	(87)
MarkWest's pre-merger EBITDA[(3)]	—	162	—
Adjusted EBITDA attributable to MPLX LP	1,419	498	166
Deferred revenue impacts	8	6	(3)
Net interest and other financial costs	(215)	(36)	(6)
Maintenance capital expenditures	(68)	(31)	(22)
Other	(4)	(6)	2
DCF pre-MarkWest undistributed	1,140	431	137
MarkWest undistributed DCF[(3)]	—	(32)	—
DCF	1,140	399	137
Preferred unit distributions	(41)	—	—
DCF attributable to GP and LP unitholders	$1,099	$ 399	$137

(1) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record the realized gain or loss of the contract.

(2) The Adjusted EBITDA adjustments related to the Predecessor are excluded from Adjusted EBITDA attributable to MPLX LP and DCF prior to the March 31, 2016 HSM acquisition.

(3) The financial and operational results of MarkWest are included in the Partnership's results from December 4, 2015, the date of the MarkWest Merger, in accordance with GAAP. The Partnership distributes and, prior to the MarkWest Merger, MarkWest distributed, all or a portion of the DCF generated in any given quarter to unitholders in the subsequent quarter. MarkWest had made a distribution for the third quarter of 2015 prior to the MarkWest Merger. However, the DCF generated by MarkWest for the period from October 1, 2015 through December 3, 2015 had not been distributed to MarkWest unitholders as of the date of the MarkWest Merger. By operation of the MarkWest Merger, the Partnership acquired such undistributed cash, along with all other assets of MarkWest, with the intent and obligation to distribute such cash to the Partnership's unitholders as part of the Partnership's fourth quarter 2015 distribution. In order to effectively include the amount of Adjusted EBITDA and DCF generated by MarkWest during the fourth quarter of 2015 prior to the date of the MarkWest Merger, and effectively include such previously undistributed cash, we have made adjustments labeled "MarkWest's pre-merger EBITDA" and "MarkWest undistributed DCF" in our reconciliations of Adjusted EBITDA and DCF to reported net income. MarkWest's pre-merger EBITDA represents Adjusted EBITDA generated by MarkWest for the period from

October 1, 2015 through December 3, 2015. MarkWest undistributed DCF represents the net adjustments made to MarkWest's pre-merger EBITDA in order to arrive at the DCF generated by MarkWest for the period from October 1, 2015 through December 3, 2015.

The amount of Adjusted EBITDA and DCF generated by MarkWest for the period of October 1, 2015 through December 3, 2015 was considered by the board of directors of the Partnership's general partner in approving the Partnership's cash distribution for the fourth quarter of 2015. In addition, we believe the inclusion of the DCF generated by MarkWest for the period of October 1, 2015 through December 3, 2015 allows for a more meaningful calculation of the Partnership's ratio of DCF generated to distributions declared for the fourth quarter of 2015. We believe the inclusion of these adjustments presents an appropriate basis for analyzing the complete operating results of the Partnership and MarkWest, on a combined basis, for the year ended December 31, 2015.

The following table presents a reconciliation of net operating margin to income from operations, the most directly comparable GAAP financial measure.

(In millions)	2016	2015	2014
Reconciliation of net operating margin to income from operations:			
Segment revenue	$2,972	$ 910	$ 747
Segment purchased product costs	(425)	(25)	—
Realized derivative loss (gain) related to revenues and purchased product costs	3	(4)	—
Net operating margin	2,550	881	747
Revenue adjustment from unconsolidated affiliates(1)	(402)	(28)	—
Realized derivative (loss) gain related to revenues and purchased product costs(2)	(3)	4	—
Unrealized derivative (losses) gains(2)	(36)	4	—
(Loss) income from equity method investments	(74)	3	—
Other income	6	6	6
Other income—related parties	101	71	40
Cost of revenues (excludes items below)	(354)	(225)	(228)
Rental cost of sales	(53)	(5)	(1)
Purchases—related parties	(316)	(166)	(153)
Depreciation and amortization	(546)	(116)	(75)
Impairment expense	(130)	—	—
General and administrative expenses	(193)	(118)	(81)
Other taxes	(43)	(13)	(10)
Income from operations	$ 507	$ 298	$ 245

(1) These amounts relate to Partnership-operated unconsolidated affiliates. The chief operating decision maker and management include these to evaluate the segment performance as we continue to operate and manage the operations. Therefore, the impact of the revenue is included for segment reporting purposes, but removed for GAAP purposes.

(2) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record the realized gain or loss of the contract.

2016 Compared to 2015

Service revenue increased $828 million in 2016 compared to 2015. This variance was primarily due to an $824 million increase due to the MarkWest Merger, a $3 million increase related to volumes of crude oil and products shipped and a $1 million increase due to higher average tariffs received on the volumes of crude oil and products shipped.

Service revenue-related parties increased $10 million in 2016 compared to 2015. This increase was primarily related to a $13 million increase in higher average tariffs received on the volumes of crude oil and products shipped, a $6 million increase related to volumes in related-party crude oil and products shipped, $3 million increase in storage fees and increased HSM equipment revenue, partially offset by a reduction in fees previously paid by HSM on behalf of MPC that are now paid directly by MPC and a $2 million decrease in revenue related to volume deficiency credits recognized.

Rental income increased $278 million in 2016 compared to 2015. This variance was due to the MarkWest Merger.

Rental income-related parties increased $13 million in 2016 compared to 2015. This increase was primarily related to a $10 million increase in HSM equipment revenue and a $3 million increase in storage fees.

Product sales increased $536 million in 2016 compared to 2015. This variance was due to the MarkWest Merger.

(Loss) income from equity method investments decreased $77 million in 2016 compared to 2015. This variance was primarily due to the MarkWest Merger combined with impairment charges of $88 million related to one of our equity method investments.

Other income-related parties increased $30 million in 2016 compared to 2015. The increase was due mainly to the MarkWest Merger and inclusion of management fee revenue for engineering and construction and administrative services for operating our unconsolidated joint ventures, offset by a decrease in fees paid to HSM by MPC.

Cost of revenues increased $129 million in 2016 compared to 2015. This variance was primarily due to the MarkWest Merger, offset by a reduction in contract services and fees previously paid by HSM on behalf of MPC that are now paid directly by MPC.

Purchased product costs increased $428 million in 2016 compared to 2015. This variance was due to the MarkWest Merger.

Rental cost of sales increased $48 million in 2016 compared to 2015. This variance was primarily due to the MarkWest Merger.

Purchases-related parties increased $150 million in 2016 compared to 2015. The increase was primarily due to higher compensation expenses provided under the omnibus and employee services agreements with MPC due to the MarkWest Merger, partially offset by increased capitalization of employee costs associated with capital projects.

Depreciation and amortization expense increased $430 million in 2016 compared to 2015. This variance was primarily due to the depreciation of the fair value of the assets acquired in the MarkWest Merger. During 2017, we expect to record accelerated depreciation related to the decommissioning of a plant in the Houston Complex of approximately $28 million in order to construct an additional 200 mmcf/d processing facility.

Impairment expense increased $130 million in 2016 compared to 2015. This variance was due to a non-cash impairment to goodwill in two reporting units in the G&P segment. See Item 8. Financial Statements and Supplementary Data—Note 18 for more information.

General and administrative expenses increased $75 million in 2016 compared to 2015. The increase was primarily due to the MarkWest Merger offset by a reduction in expenses due to changes in allocations provided for in the omnibus and employee services agreements with MPC as well as $30 million of acquisition costs incurred in connection with the MarkWest Merger in 2015.

Other taxes increased $30 million in 2016 compared to 2015. The increase was primarily due to property taxes related to the MarkWest Merger.

Interest expense and other financial costs increased $213 million in 2016 compared to 2015. The increase was primarily due to the senior notes assumed as part of the MarkWest Merger.

During 2016 and 2015, MPC did not ship its minimum committed volumes on certain of our pipeline systems. As a result, MPC was obligated to make $48 million and $44 million of deficiency payments in 2016 and 2015, respectively. We record deficiency payments as *Deferred revenue-related parties* on our Consolidated Balance Sheets. During 2016 and 2015, we recognized revenue of $40 million and $38 million, respectively, related to volume deficiency credits. At December 31, 2016 and 2015, the cumulative balance of *Deferred revenue-related parties* on our Consolidated Balance Sheets related to volume deficiencies was $44 million and $36 million, respectively. The following table presents the future expiration dates of the associated deferred revenue credits for 2016:

(In millions)	
March 31, 2017	$ 8
June 30, 2017	9
September 30, 2017	7
December 31, 2017	9
March 31, 2018	2
June 30, 2018	2
September 30, 2018	3
December 31, 2018	4
Total	$44

We will recognize revenue for the deficiency payments in future periods at the earlier of when volumes are transported in excess of the minimum quarterly volume commitments, when it becomes impossible to physically transport volumes necessary to utilize the accumulated credits or upon expiration of the make-up period. Deficiency payments are included in the determination of DCF in the period in which a deficiency occurs.

2015 Compared to 2014

Service revenue increased $60 million in 2015 compared to 2014. This variance was primarily due to an $63 million increase in the G&P segment from the MarkWest Merger and a $2 million increase resulting from higher average tariffs received on the volumes of crude oil and products shipped, partially offset by a $5 million decrease related to a 13 mbpd reduction in third-party crude oil and products volumes shipped.

Service revenue-related parties decreased $69 million in 2015 compared to 2014. This decrease was primarily related to the reclassification of income from the transportation service agreement entered into by HSM with MPC in 2015. After January 2015, it was considered an operating lease, and therefore, a portion of the revenue was included in rental income-related parties. This decrease was also related to an agreement entered into by HSM with MPC for the maintenance repair facility which was included in other income in 2015 and a $7 million decrease in revenue related to volume deficiency credits recognized, partially offset by a $32 million increase due to higher average tariffs received on the volumes of crude oil and products shipped.

Rental income increased $20 million in 2015 compared to 2014 related entirely to the MarkWest Merger.

Rental income-related parties increased $86 million in 2015 compared to 2014. This increase was primarily related to the transportation service agreement entered into by HSM with MPC in January 2015. Prior to January 2015, this agreement was not considered an operating lease and the income was included in service revenue-related parties.

Product sales increased $36 million in 2015 compared to 2014. This variance was due to the MarkWest Merger.

Other income and other income-related parties increased a total of $34 million in 2015 compared to 2014. The increase was primarily due to an increase in fees received for operating MPC's private pipeline systems, a reclassification of fees received from the agreements for the maintenance repair facility and an increase due to the MarkWest Merger.

Cost of revenues decreased $3 million in 2015 compared to 2014 primarily due to the MarkWest Merger, partially offset by decrease in average fuel costs. The variance was also due to costs associated with rental income from the operating lease entered into in January 2015 which were reclassified to rental cost of sales.

Rental cost of sales increased $4 million in 2015 compared to 2014 primarily due costs associated with rental income which were reclassified from cost of revenues related to the HSM transportation services agreement entered into in January 2015.

Purchased product costs increased $20 million in 2015 compared to 2014. This variance was due to the MarkWest Merger.

Purchases-related parties increased $13 million in 2015 compared to 2014. The increase was primarily due to higher compensation expenses provided under the omnibus and employee services agreements with MPC, partially offset by increased capitalization of employee costs associated with capital projects.

Depreciation and amortization expense increased $41 million in 2015 compared to 2014 primarily due to the MarkWest Merger.

General and administrative expenses increased $37 million in 2015 compared to 2014. The increase in 2015 was primarily related to $30 million in acquisition costs.

Other taxes increased $3 million in 2015 compared to 2014. The increase was primarily due to property taxes from the MarkWest Merger.

Interest expense and other financial costs increased $43 million in 2015 compared to 2014. The increase was due to borrowings on the bank revolving credit facility, term loan and senior notes in connection with the MarkWest Merger. The increase was also due to $6 million in transaction costs related to the exchange of MarkWest senior notes for MPLX LP senior notes.

SEGMENT REPORTING

We classify our business in the following reportable segments: L&S and G&P. Segment operating income represents income from operations attributable to the reportable segments. We have investments in entities that we operate that are accounted for using equity method investment accounting standards. However, we view financial information as if those investments were consolidated. Corporate general and administrative expenses, unrealized derivative gains (losses), property, plant and equipment impairment, goodwill impairment and depreciation and amortization are not allocated to the reportable segments. Management does not consider these items allocable to or controllable by any individual segment and, therefore, excludes these items when evaluating segment performance. Segment results are also adjusted to exclude the portion of income from operations attributable to the noncontrolling interests related to partially-owned entities that are either consolidated or accounted for as equity method investments. Segment operating income attributable to MPLX LP excludes the operating income related to the Predecessor of the inland marine business prior to the March 31, 2016 acquisition.

The tables below present information about segment operating income for the reported segments for the years ended December 31, 2016, 2015 and 2014.

L&S Segment

(In millions)	2016	2015	2014
Revenues and other income:			
Segment revenues	$787	$760	$747
Segment other income	68	75	46
Total segment revenues and other income	855	835	793
Costs and expenses:			
Segment cost of revenues	368	379	392
Segment operating income before portion attributable to noncontrolling interest and Predecessor	487	456	401
Segment portion attributable to noncontrolling interest and Predecessor	34	134	188
Segment operating income attributable to MPLX LP	$453	$322	$213

2016 Compared to 2015

Segment revenue increased $27 million due to a $14 million increase in higher average tariffs received on the volumes of crude oil and products shipped, $9 million related to increased volumes of crude oil and products shipped, a $6 million increase in storage income and increased HSM equipment revenue, partially offset by a reduction in fees previously paid by HSM on behalf of MPC that are now paid directly by MPC and a $2 million decrease in revenue related to volume deficiency credits recognized.

Segment other income decreased $7 million primarily due to a reduction in fees paid to HSM by MPC.

Segment cost of revenues decreased $11 million primarily due to a decrease in fees previously paid by HSM on behalf of MPC that are now being paid directly by MPC and a decrease in expenses related to the timing of maintenance projects.

Segment portion attributable to noncontrolling interest and Predecessor decreased primarily due to the acquisition of HSM as of March 31, 2016.

2015 Compared to 2014

Segment revenue increased due to a $13 million increase in higher average tariffs received on the volumes of crude oil and products shipped, partially offset by a $7 million decrease in revenue related to volume deficiency credits recognized and a decrease due to an agreement entered into by HSM with MPC for the maintenance repair facility which was included in other income in 2015.

Segment other income increased $29 million due to an increase in storage fees, other revenue related to the expansion of the Patoka Tank Farms and an increase from an agreement entered into by HSM with MPC for the maintenance repair facility which was included in segment revenue prior to 2015.

Segment cost of revenues decreased $13 million primarily due a decrease in the average fuel costs and increased capitalization of employee costs associated with capital projects, partially offset by higher compensation expenses provided under the omnibus and employee services agreements with MPC.

Segment portion attributable to noncontrolling interest and Predecessor decreased primarily due to the acquisition of the remaining interest of Pipe Line Holdings, of which the 0.5 percent was purchased on December 4, 2015 and the change in the segment portion attributable to Predecessor.

G&P Segment

(In millions)	2016	2015	2014
Revenues and other income:			
Segment revenues	$2,185	$150	$—
Segment other income	1	—	—
Total segment revenues and other income	2,186	150	—
Costs and expenses:			
Segment cost of revenues	907	62	—
Segment operating income before portion attributable to noncontrolling interest	1,279	88	—
Segment portion attributable to noncontrolling interest	147	12	—
Segment operating income attributable to MPLX LP	$1,132	$ 76	$—

The G&P segment increased overall due to the MarkWest Merger. There was no G&P segment prior to the MarkWest Merger. See Supplemental MD&A—G&P Pro Forma for more information.

Segment Reconciliations

The following tables provide reconciliations of segment operating income to our consolidated income from operations, segment revenue to our consolidated total revenues and other income, and segment portion attributable to noncontrolling interest to our consolidated net income attributable to noncontrolling interests for the years ended December 31, 2016, 2015 and 2014. Adjustments related to unconsolidated affiliates relate to our Partnership-operated non-wholly-owned entities that we consolidate for segment purposes. (Loss) income from equity method investments relates to our portion of income from our unconsolidated joint ventures of which Partnership-operated joint ventures are consolidated for segment purposes. Other income-related parties consists of operational service fee revenues from our operated unconsolidated affiliates. Unrealized derivative activity is not allocated to segments.

(In millions)	2016	2015	2014
Reconciliation to Income from operations:			
L&S segment operating income attributable to MPLX LP	$ 453	$ 322	$213
G&P segment operating income attributable to MPLX LP	1,132	76	—
Segment operating income attributable to MPLX LP	1,585	398	213
Segment portion attributable to unconsolidated affiliates	(173)	(8)	85
Segment portion attributable to Predecessor	34	133	103
(Loss) income from equity method investments	(74)	3	—
Other income—related parties	40	2	—
Unrealized derivative (losses) gains[(1)]	(36)	4	—
Depreciation and amortization	(546)	(116)	(75)
Impairment expense	(130)	—	—
General and administrative expenses	(193)	(118)	(81)
Income from operations	$ 507	$ 298	$245

(In millions)	2016	2015	2014
Reconciliation to Total revenues and other income:			
Total segment revenues and other income	$3,041	$ 985	$ 793
Revenue adjustment from unconsolidated affiliates	(402)	(28)	—
(Loss) income from equity method investments	(74)	3	—
Other income—related parties	40	2	—
Unrealized derivative losses[1]	(15)	(1)	—
Total revenues and other income	$2,590	$ 961	$ 793

(in millions)	2016	2015	2014
Reconciliation to Net income attributable to noncontrolling interests and Predecessor:			
Segment portion attributable to noncontrolling interest and Predecessor	$ 181	$ 146	$ 188
Portion of noncontrolling interests and Predecessor related to items below segment income from operations	(124)	(48)	(70)
Portion of operating income attributable to noncontrolling interests of unconsolidated affiliates	(32)	(5)	—
Net income attributable to noncontrolling interests and Predecessor	$ 25	$ 93	$ 118

(1) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record the realized gain or loss of the contract.

SUPPLEMENTAL MD&A—G&P PRO FORMA

The tables below present financial information, as evaluated by management, for the reported segments for the years ended December 31, 2016, 2015 and 2014. This is a supplemental disclosure showing G&P segment results as if it were acquired as of January 1, 2014 and it incorporates pro forma adjustments necessary, including the removal of approximately $90 million of transaction costs, to reflect a January 1, 2014 acquisition date (see reconciliations below). The pro forma information was prepared in a manner consistent with Article 11 of Regulation S-X and FASB ASC Topic 805 (see Item 8. Financial Statements and Supplementary Data—Note 4). Results provided for the year ended December 31, 2016 reflect actual results. We believe this data will provide a more meaningful discussion of trends for the G&P segment as it helps convey the impact of commodity pricing and volume changes to the business. Future results may vary significantly from the results reflected below because of various factors. In addition, all Partnership-operated, non-wholly- owned subsidiaries are treated as if they are consolidated for segment reporting purposes (for more information on how management has determined our segments see Item 8. Financial Statements and Supplementary Data—Note 10).

(In millions)	2016	2015	2014
Revenues and other income:			
Segment revenues	$2,185	$2,007	$2,168
Segment other income	1	—	—
Total segment revenues and other income	2,186	2,007	2,168
Costs and expenses:			
Segment cost of revenues	907	875	1,197
Segment operating income before portion attributable to noncontrolling interest	1,279	1,132	971
Segment portion attributable to noncontrolling interest	147	121	36
Segment operating income attributable to MPLX LP	$1,132	$1,011	$ 935

2016 Compared to 2015

Segment revenues and other income increased $179 million in 2016 due to favorable fee revenues from increases in total gathering throughput, total natural gas processed and total C2+ NGLs fractionated volumes of 11 percent, 13 percent and 25 percent, respectively. Volumes increased due to new processing plants in the Marcellus and Southwest areas, additional fractionation capacity in the Marcellus area and increased dry gas gathering in the Utica area. The increased fee revenues were partially offset by lower contributions from commodity derivative settlements.

Segment cost of revenues increased $32 million due to increased operating costs from expanded plant capacities offset by lower product costs due to changes in component mix, lower Marcellus purchases related to inventory, and favorable line fill valuation due to higher liquid pricing.

The change in the segment portion of operating income attributable to noncontrolling interests increased due to ongoing growth in our entities that are not wholly-owned.

2015 Compared to 2014

Segment revenue decreased due to a 39 percent decrease in natural gas prices and a 50 percent decrease in NGL prices over the same period in 2014. There was a $151 million decrease in inventory sold compared to the same period in 2014 due to changes in contractual terms. This decrease was partially offset by an increase in volumes. Total gathering throughput, total natural gas processed and total C2+ NGLs fractionated volumes increased by 28 percent, 36 percent and 30 percent, respectively.

Segment cost of revenues decreased mainly due to a decrease of $152 million in inventory sold compared to the same period in 2014 due to changes in contractual terms and decreases in natural gas purchased prices and NGL prices. Segment cost of revenues as a percentage of segment revenue decreased 13 percent for the year ended December 31, 2015 compared to the same period in 2014. This decrease was primarily due to an increase in fee revenue as a percent of total revenue by 16 percent. The decreases were partially offset by increased expenses related to the expansion of Utica and Marcellus operations.

The change in the segment portion of operating income attributable to noncontrolling interests increased due to ongoing growth in our entities that are not wholly owned.

Reconciliation of Segment Operating Income to Consolidated Income Before Provision for Income Tax

The following tables provide reconciliations of G&P segment revenues and other income to total revenues and other income and G&P's segment operating income attributable to MPLX LP to net income attributable to MPLX LP, for the years ended December 31, 2016, 2015 and 2014, respectively. The items listed below the *Other income—related parties* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

(In millions)	2016	2015	2014
Pro forma reconciliation to total revenues and other income:			
Total G&P segment revenues and other income	$2,186	$2,007	$2,168
Revenue adjustment from unconsolidated affiliates[(1)]	(402)	(159)	(41)
(Loss) income from equity method investments	(74)	8	(12)
G&P other income (loss)—related parties	40	(4)	19
Unrealized derivative (losses) gains related to revenue[(2)]	(15)	(10)	25
Total pro forma G&P revenues and other income	1,735	1,842	2,159
Total pro forma L&S revenues and other income	855	835	813
Total pro forma revenues and other income	$2,590	$2,677	$2,972

(In millions)	2016	2015	2014
Pro forma reconciliation to pro forma net income attributable to MPLX LP:			
L&S segment operating income attributable to MPLX LP	$ 453	$ 322	$ 266
G&P segment operating income attributable to MPLX LP	1,132	76	—
Pro forma G&P segment operating income attributable to MPLX LP	—	935	935
Segment portion attributable to unconsolidated affiliates[(1)]	(320)	(29)	(8)
Segment portion attributable to noncontrolling interest and Predecessor	181	182	21
(Loss) income from equity method investments	(74)	8	(12)
Other income (loss)—related parties	40	(5)	19
Unrealized derivative (losses) gains[(2)]	(36)	(10)	82
Depreciation and amortization	(546)	(575)	(481)
Impairment expense	(130)	(26)	(62)
General and administrative expenses	(193)	(209)	(130)
Pro forma income from operations	507	669	630
Related party interest and other financial costs	1	—	—
Debt retirement expense	—	118	—
Net interest and other financial costs	260	259	189
Pro forma income before income taxes	246	292	441
(Benefit) provision for income taxes	(12)	(10)	46
Pro forma net income	258	302	395
Less: Net income attributable to noncontrolling interests	25	55	66
Pro forma net income attributable to MPLX LP	$ 233	$ 247	$ 329

(1) The Partnership consolidated the Utica Operations until December 4, 2015 at which point these were accounted for as unconsolidated affiliates.

(2) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record the realized gain or loss of the contract.

	2016	2015	2014
Pro Forma Operating Statistics			
Gathering Throughput (mmcf/d)			
Marcellus Operations	910	858	668
Utica Operations(1)	932	673	289
Southwest Operations(2)	1,433	1,413	1,336
Total gathering throughput	3,275	2,944	2,293
Natural Gas Processed (mmcf/d)			
Marcellus Operations	3,210	2,861	2,064
Utica Operations(1)	1,072	883	416
Southwest Operations	1,226	1,077	991
Southern Appalachian Operations	253	267	280
Total natural gas processed	5,761	5,088	3,751
C2 + NGLs Fractionated (mbpd)			
Marcellus Operations(3)	260	194	147
Utica Operations(1)(3)	42	40	19
Southwest Operations	18	18	21
Southern Appalachian Operations(4)	15	15	19
Total C2 + NGLs fractionated(5)	335	267	206
Pricing Information			
Natural Gas NYMEX HH ($/MMBtu)	$ 2.55	$ 2.63	$ 4.28
C2 + NGL Pricing/gallon(6)	$ 0.47	$ 0.46	$ 0.92

(1) Utica was a consolidated equity method investment prior to December 4, 2015. After this date, it became an unconsolidated equity method investment but is consolidated for segment purposes only.

(2) Includes approximately 309 mmcf/d, 242 mmcf/d and 228 mmcf/d related to unconsolidated equity method investments, Wirth and MarkWest Pioneer, for the years ended December 31, 2016, 2015 and 2014, respectively.

(3) Hopedale is jointly owned by Ohio Fractionation and MarkWest Utica EMG. Ohio Fractionation is a subsidiary of MarkWest Liberty Midstream. MarkWest Liberty Midstream and MarkWest Utica EMG are entities that operate in the Marcellus and Utica regions, respectively. The Marcellus Operations includes its portion utilized of the jointly owned Hopedale Fractionation Complex. The Utica Operations includes Utica's portion utilized of the jointly owned Hopedale Fractionation Complex.

(4) Includes NGLs fractionated for the Marcellus and Utica Operations.

(5) Purity ethane makes up approximately 128 mbpd, 79 mbpd and 67 mbpd of total fractionated products for the years ended December 31, 2016, 2015 and 2014, respectively.

(6) C2 + NGL pricing based on Mont Belvieu prices assuming an NGL barrel of approximately 35 percent ethane, 35 percent propane, 6 percent Iso-Butane, 12 percent normal butane and 12 percent natural gasoline.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

Our cash and cash equivalents balance was $234 million at December 31, 2016 compared to $43 million at December 31, 2015. The change in cash and cash equivalents was due to the factors discussed below. Net cash provided by (used in) operating activities, investing activities and financing activities for the past three years were as follows:

(In millions)	2016	2015	2014
Net cash provided by (used in):			
Operating activities	$ 1,288	$ 340	$ 334
Investing activities	(1,212)	(1,599)	(137)
Financing activities	115	1,275	(224)
Total	$ 191	$ 16	$ (27)

Cash Flows Provided by Operating Activities. Net cash provided by operating activities increased $948 million in 2016 compared to 2015, primarily due to increased operating results as result of the MarkWest Merger as well as favorable changes in working capital of approximately $143 million compared to 2015.

For 2016, changes in working capital were a net $89 million source of cash. Accounts payable and accrued liabilities increased $100 million from year-end 2015 due mainly to an increase in our product and freight accruals as a result of higher NGL prices as well as timing related to general operating payables. Current receivables increased $52 million primarily due to higher NGL prices and volumes as compared to 2015, and there was an increase in the liability positions of our derivatives due to changes in the fair value of $43 million that were primarily due to increases in commodity prices during 2016.

For 2015, changes in working capital were a net $54 million use of cash. Current receivables increased $29 million primarily due to higher third-party tariff revenue receivables. Net liabilities to related parties decreased $22 million due to timing of payables to related parties.

For 2014, changes in working capital were a net $19 million source of cash, primarily due to an increase in net liabilities to related parties and a decrease in current receivables. Net liabilities to related parties increased $15 million, primarily due to an increase in payables to related parties under the omnibus and employee services agreements and a decrease in receivables from related parties.

Cash Flows Used in Investing Activities. Net cash used in investing activities decreased $387 million in 2016 compared to 2015, primarily due to a $918 million use of cash for additions to property, plant and equipment and a $73 million use of cash for investments in unconsolidated affiliates, offset by a $1.2 billion decrease in acquisitions due to the MarkWest Merger and $154 million source of cash from investment loans between HSM and related parties prior to the HSM acquisition.

Net cash used in investing activities increased $1.5 billion in 2015 compared to 2014, primarily due to a $1.2 billion increase in acquisitions due to the MarkWest Merger and a $147 million increase in additions to property, plant and equipment.

Net cash used in investing activities in 2014 was primarily used for additions to property, plant, and equipment.

Cash Flows from Financing Activities. Net cash provided by financing activities in 2016 was $115 million compared to $1.3 billion in 2015. The sources of cash in 2016 primarily consisted of $984 million in net proceeds from the issuance of Preferred units and $792 million of net cash proceeds from the issuance of common units and general partner units, as well as contributions of $225 million from MPC as part of the Class A Reorganization. The uses of cash in 2016 primarily consisted of net repayments of long-term debt and distributions to unitholders.

The sources of cash in 2015 primarily consisted of contributions of $1.2 billion from MPC for the MarkWest Merger and proceeds of $169 million from issuances of general partner units. The uses of cash in 2015 primarily consisted of distributions to unitholders.

The sources of cash in 2014 primarily consisted of net long-term borrowings and proceeds from the issuance of common units. The uses of cash in 2014 primarily consisted of distributions of $910 million to MPC for the acquisition of an interest in Pipe Line Holdings, as well as distributions to unitholders.

Cash used in distributions to unitholders totaled $845 million in 2016, $158 million in 2015, and $103 million in 2014. The increase in 2016 was primarily due to the issuance of units to MarkWest unitholders in connection with the merger on December 4, 2015.

Long-term debt borrowings and repayments were a net $878 million use of cash in 2016 compared to a $38 million source of cash in 2015 and a $631 million source of cash in 2014. During 2016, we used proceeds from the issuance of Preferred units to repay amounts outstanding under the bank revolving credit facility. During 2015, we used proceeds from the issuance of $500 million aggregate of principal amount of senior notes to repay $385 million outstanding under the bank revolving credit facility. See Item 8. Financial Statements and Supplemental Data—Note 17 for additional information on our long-term debt.

Debt and Liquidity Overview

Our outstanding borrowings at December 31, 2016 and 2015 consisted of the following:

	December 31,	
(In millions)	2016	2015
MPLX LP:		
Bank revolving credit facility due 2020	$ —	$ 877
Term loan facility due 2019	250	250
5.500% senior notes due 2023	710	710
4.500% senior notes due 2023	989	989
4.875% senior notes due 2024	1,149	1,149
4.000% senior notes due 2025	500	500
4.875% senior notes due 2025	1,189	1,189
Consolidated subsidiaries:		
MarkWest—4.500%—5.500%, due 2023—2025	63	63
MPL—capital lease obligations due 2020	8	9
Total	4,858	5,736
Unamortized debt issuance costs	(7)	(8)
Unamortized discount(1)	(428)	(472)
Amounts due within one year	(1)	(1)
Total long-term debt due after one year	$4,422	$5,255

(1) Includes $420 million and $464 million discount as of December 31, 2016 and 2015, respectively, related to the difference between the fair value and the principal amount of the assumed MarkWest debt.

On November 20, 2014, MPLX LP entered into a credit agreement with a syndicate of lenders ("MPLX Credit Agreement") which provides for a five-year, $1 billion bank revolving credit facility and a $250 million term loan facility. In connection with the closing of the MarkWest Merger, we amended our MPLX Credit Agreement to, among other things, increase the aggregate amount of revolving credit capacity under the credit agreement by $1 billion, for total aggregate commitments of $2 billion, and to extend the maturity of the revolving credit facility to December 4, 2020. The term loan facility was not amended and matures on November 20, 2019. Also in connection with the closing of the MarkWest Merger, MarkWest's bank revolving credit facility was terminated and the approximately $943 million outstanding under MarkWest's bank revolving credit facility was repaid with $850 million of borrowings under MPLX LP's bank revolving credit facility and $93 million of cash. We incurred approximately $2 million of costs related to the borrowing on the bank revolving credit facility.

The bank revolving credit facility includes letter of credit issuing capacity of up to $250 million and swingline capacity of up to $100 million. The borrowing capacity under the MPLX Credit Agreement may be increased by up to an additional $500 million, subject to certain conditions, including the consent of lenders whose commitments would increase. In addition, the maturity date may be extended from time-to-time during its term to a date that is one year after the then-effective maturity subject to the approval of lenders holding the majority of the commitments then outstanding, provided that the commitments of any non-consenting lenders will be terminated on the then-effective maturity date. During 2016, we borrowed $434 million under the bank revolving credit facility, at an average interest rate of 1.9 percent, and repaid $1.3 billion under the bank revolving credit facility. At December 31, 2016, we had no borrowings and $3 million in letters of credit outstanding under this facility, resulting in total unused loan availability of $2.0 billion, or 99.9 percent of the borrowing capacity.

The term loan facility was drawn in full on November 20, 2014. The maturity date for the term loan facility may be extended for up to two additional one-year periods subject to the consent of the lenders holding a majority of the outstanding term loan borrowings, provided that the portion of the term loan borrowings held by any non-consenting lenders will continue to be due and payable on the then-effective maturity date. The borrowings under this facility during 2016 were at an average interest rate of 1.954 percent.

Borrowings under the MPLX Credit Agreement bear interest at either the Adjusted LIBOR or the Alternate Base Rate (as defined in the MPLX Credit Agreement), at our election, plus a specified margin. We are charged various fees and expenses in connection with the agreement, including administrative agent fees, commitment fees on the unused portion of the bank revolving credit facility and fees with respect to issued and outstanding letters of credit. The applicable margins to the benchmark interest rates and certain of the fees fluctuate based on the credit ratings in effect from time to time on our long-term debt.

The MPLX Credit Agreement includes certain representations and warranties, affirmative and negative covenants and events of default that we consider usual and customary for an agreement of that type and that could, among other things, limit our ability to pay distributions to our unitholders. The financial covenant requires us to maintain a ratio of Consolidated Total Debt as of the end of each fiscal quarter to Consolidated EBITDA (both as defined in the MPLX Credit Agreement) for the prior four fiscal quarters of no greater than 5.0 to 1.0 (or 5.5 to 1.0 for up to two fiscal quarters following certain acquisitions). Consolidated EBITDA is subject to adjustments for certain acquisitions completed and capital projects undertaken during the relevant period. Other covenants restrict us and certain of our subsidiaries from incurring debt, creating liens on our assets and entering into transactions with affiliates. As of December 31, 2016, we were in compliance with this financial covenant with a ratio of Consolidated Total Debt to Consolidated EBITDA of 3.26 to 1.0, as well as all other covenants contained in the MPLX Credit Agreement.

As of December 31, 2016, we had five series of senior notes outstanding: $750 million in aggregate principal amount on the senior notes issued in August 2012 and due February 2023; $1.0 billion aggregate principal amount on senior notes issued in January 2013 and due July 2023; $1.2 billion aggregate principal amount on senior notes issued in November 2014 and due in December 2024; $500 million aggregate principal amount on senior notes issued in February 2015 and due February 2025; and $1.2 billion aggregate principal amount on senior notes issued in June 2015 and due in June 2025 (altogether the "Senior Notes Outstanding"). As of December 31, 2016, there were no minimum principal payments on the Senior Notes Outstanding due during the next five years. For further discussion of the Senior Notes Outstanding and other debt related information, see Item 8. Financial Statements and Supplementary Data—Note 17.

On February 10, 2017, the Partnership completed a public offering of $1.25 billion aggregate principal amount of 4.125 percent unsecured senior notes due March 2027 (the "2027 Senior Notes") and $1.0 billion aggregate principal amount of 5.200 percent unsecured senior notes due March 2047 (the “2047 Senior Notes” and, collectively with the 2027 Senior Notes, the “New Senior Notes”). The 2027 Senior Notes and the 2047 Senior Notes were offered at a price to the public of 99.834 percent and 99.304 percent of par, respectively. The Partnership intends to use the net proceeds from this offering for general partnership purposes, which may include, from time to time, acquisitions (including the previously announced planned dropdown of assets from MPC, the acquisition of the Ozark pipeline, and the acquisition of a partial, indirect equity interest in the Bakken Pipeline system) and capital expenditures.

Our intention is to maintain an investment grade credit profile. As of January 31, 2017, we had the following credit rating grade levels.

Rating Agency	Rating
Fitch	BBB- (stable outlook)
Moody’s	Baa3 (stable outlook)
Standard & Poor’s	BBB- (stable outlook)

The ratings reflect the respective views of the rating agencies. Although it is our intention to maintain a credit profile that supports an investment grade rating, there is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant.

The MPLX Credit Agreement does not contain credit rating triggers that would result in the acceleration of interest, principal or other payments in the event that our credit ratings are downgraded. However, any downgrades in the credit ratings of our senior unsecured debt ratings to below investment grade ratings would increase the applicable interest rates and other fees payable under the MPLX Credit Agreement and may limit our flexibility to obtain future financing.

Our liquidity totaled $2.7 billion at December 31, 2016, consisting of:

	December 31, 2016		
(In millions)	Total Capacity	Outstanding Borrowings	Available Capacity
MPLX LP—bank revolving credit facility(1)	$ 2,000	$ (3)	$ 1,997
MPC Investment—loan agreement	500	—	500
Total	$ 2,500	$ (3)	$ 2,497
Cash and cash equivalents			234
Total liquidity			$ 2,731

(1) Outstanding borrowings include $3 million in letters of credit outstanding under this facility.

We expect our ongoing sources of liquidity to include cash generated from operations, borrowings under our revolving credit agreements and issuances of additional debt and equity securities. We believe that cash generated from these sources will be sufficient to meet our short-term and long-term funding requirements, including working capital requirements, capital expenditure requirements, acquisitions, contractual obligations, repayment of debt maturities and quarterly cash distributions. MPC manages our cash and cash equivalents on our behalf directly with third-party institutions as part of the treasury services that it provides to us under our omnibus agreement. From time to time, we may also consider utilizing other sources of liquidity, including the formation of joint ventures or sales of non-strategic assets.

Equity and Preferred Units Overview

The table below summarizes the changes in the number of units outstanding through December 31, 2016:

(In units)	Common	Class B	Subordinated	General Partner	Total
Balance at December 31, 2013	36,951,515	—	36,951,515	1,508,225	75,411,255
Unit-based compensation awards	15,479	—	—	316	15,795
Contribution of interest in Pipe Line Holdings	2,924,104	—	—	59,676	2,983,780
December 2014 equity offering	3,450,000	—	—	70,408	3,520,408
Balance at December 31, 2014	43,341,098	—	36,951,515	1,638,625	81,931,238
Unit-based compensation awards	18,932	—	—	386	19,318
Issuance of units under the ATM program	25,166	—	—	514	25,680
Subordinated unit conversion	36,951,515	—	(36,951,515)	—	—
MarkWest Merger	216,350,465	7,981,756	—	5,160,950	229,493,171
Balance at December 31, 2015	296,687,176	7,981,756	—	6,800,475	311,469,407
Unit-based compensation awards	120,989	—	—	2,470	123,459
Issuance of units under the ATM Program	26,347,887	—	—	537,710	26,885,597
Contribution of HSM	22,534,002	—	—	459,878	22,993,880
Class B conversion	4,350,057	(3,990,878)	—	7,330	366,509
Class A Reorganization	7,153,177	—	—	(436,758)	6,716,419
Balance at December 31, 2016	357,193,288	3,990,878	—	7,371,105	368,555,271

For more details on equity activity, see Item 8. Financial Statements and Supplementary Data—Notes 8 and 9.

On May 13, 2016, the Partnership completed the private placement of approximately 30.8 million Preferred units for a cash purchase price of $32.50 per unit. The aggregate net proceeds of approximately $984 million from the sale of the Preferred units will be used for capital expenditures, repayment of debt and general partnership purposes.

The Preferred units rank senior to all common units with respect to distributions and rights upon liquidation. The holders of the Preferred units are entitled to receive cumulative quarterly distributions equal to $0.528125 per unit commencing for the quarter ended June 30, 2016, with a prorated amount from the date of issuance. Following the second anniversary of the issuance of the Preferred units, the holders of the Preferred units will receive as a distribution the greater of $0.528125 per unit or the amount of per unit distributions paid to common units. Since the Preferred unit distribution was declared subsequent to the end of the second quarter of 2016, the distribution was not accrued to the Preferred unit holders' capital account. For the quarter ended June 30, 2016, the Preferred units received an earned aggregate cash distribution of $9 million, based on the quarterly per unit distribution prorated for the 49-day period the Preferred units were outstanding during the second quarter of 2016. Distributions paid to Preferred unit holders for the year ended December 31, 2016 was $25 million.

On July 1, 2016, 3,990,878 Class B units automatically converted into 1.09 MPLX LP common units and the right to receive $6.20 per unit in cash. They also received the second quarter distribution. MPC funded this cash payment, which reduced our liability payable to Class B unitholders by approximately $25 million on July 1, 2016. As a result of the Class B conversion on July 1, 2016, MPLX GP contributed less than $1 million in exchange for 7,330 general partner units to maintain its two percent general partner interest.

On August 4, 2016, the Partnership entered into a second amended and restated distribution agreement providing for the continuous issuance of up to an aggregate of $1.2 billion of common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of any offerings. The Partnership expects the net proceeds from sales under the ATM Program will be used for general partnership purposes including repayment or refinancing of debt and funding for acquisitions, working capital requirements and capital expenditures. During the year ended December 31, 2016, the sale of common units under the ATM Program generated net proceeds of approximately $776 million.

On September 1, 2016, the Partnership and various affiliates initiated a series of reorganization transactions in order to simplify the Partnership's ownership structure and its financial and tax reporting requirements. In connection with these transactions, all issued and outstanding MPLX LP Class A units were either distributed to or purchased by MPC in exchange for $84 million in cash, 21,401,137 MPLX LP common units and 436,758 MPLX LP general partner units. MPC also contributed $141 million to facilitate the repayment of intercompany debt between MarkWest Hydrocarbon and MarkWest. As a result of these transactions, the MPLX LP Class A units were eliminated, are no longer outstanding and no longer participate in distributions of cash from the Partnership. See additional discussion in Item 8. Financial Statements and Supplementary Data—Notes 8 and 12.

We intend to pay a minimum quarterly distribution of $0.2625 per unit, which equates to $96 million per quarter, or $384 million per year, based on the number of common and general partner units. On January 25, 2017, we announced that the board of directors of our general partner had declared a distribution of $0.5200 per unit that was paid on February 14, 2017 to unitholders of record on February 6, 2017. This represents a four percent increase over the fourth quarter 2015 distribution. On February 1, 2017, we announced distribution growth guidance of 12 to 15 percent for 2017. This increase in the distribution is consistent with our intent to maintain an attractive distribution growth profile over the long term. Although our partnership agreement requires that we distribute all of our available cash each quarter, we do not otherwise have a legal obligation to distribute any particular amount per common unit.

The allocation of total quarterly cash distributions to general and limited partners is as follows for the years ended December 31, 2016, 2015 and 2014. Our distributions are declared subsequent to quarter end; therefore, the following table represents total cash distributions applicable to the period in which the distributions were earned.

(In millions)	2016	2015	2014
Distribution declared:			
Limited partner units—public	$ 533	$ 151	$ 29
Limited partner units—MPC	159	104	77
General partner units—MPC	18	6	2
Incentive distribution rights—MPC	187	54	4
Total GP & LP distribution declared	897	315	112
Redeemable preferred units	41	—	—
Total distribution declared	$ 938	$ 315	$ 112
Cash distributions declared per limited partner common unit:			
Quarter ended March 31	$0.5050	$0.4100	$0.3275
Quarter ended June 30	0.5100	0.4400	0.3425
Quarter ended September 30	0.5150	0.4700	0.3575
Quarter ended December 31	0.5200	0.5000	0.3825
Year ended December 31	$2.0500	$1.8200	$1.4100

Capital Expenditures

Our operations are capital intensive, requiring investments to expand, upgrade, enhance or maintain existing operations and to meet environmental and operational regulations. Our capital requirements consist of maintenance capital expenditures and growth capital expenditures. Examples of maintenance capital expenditures are those made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. In contrast, growth capital expenditures are those incurred for acquisitions or capital improvements that we expect will increase our operating capacity to increase volumes gathered, processed, transported or fractionated, decrease operating expenses within our facilities or increase operating income over the long term. Examples of growth capital expenditures include the acquisition of equipment or the construction costs associated with new well connections, and the development or acquisition of additional pipeline, processing or storage capacity. In general, growth capital includes costs that are expected to generate additional or new cash flow for the Partnership.

Our capital expenditures for the past three years are shown in the table below:

(In millions)	2016	2015	2014
Capital expenditures:			
Maintenance	$ 68	$ 33	$ 30
Expansion	1,118	282	124
Total capital expenditures	1,186	315	154
Less: (Decrease) increase in capital accruals	(25)	26	11
Asset retirement expenditures	5	1	2
Additions to property, plant and equipment	1,206	288	141
Capital expenditures of unconsolidated subsidiaries(1)	131	24	—
Total gross capital expenditures	1,337	312	141
Less: Joint venture partner contributions(2)	64	8	—
Total capital expenditures, net	1,273	304	141
Less: Maintenance capital	72	33	30
Total growth capital	1,201	271	111
Acquisition, net of cash acquired	—	1,218	—
Total growth capital and acquisition	$1,201	$1,489	$111

(1) Includes amounts related to unconsolidated, Partnership-operated subsidiaries.

(2) This represents estimated joint venture partners share of growth capital.

Our growth capital plan range for 2017 is $1.4 billion to $1.7 billion, not including the dropdowns or acquisitions previously discussed in Item 1. Business—Competitive Strengths, or their respective subsequent capital spending. The G&P segment capital plan includes investments that are expected to support producer customers. The L&S segment capital plan includes the development of various crude oil and refined petroleum products infrastructure projects, including a build out of Utica Shale infrastructure in connection with the recently completed Cornerstone Pipeline, a butane cavern and a tank farm expansion. We also have large organic growth prospects associated with the anticipated growth of MPC's operations and third-party activity in our areas of operation that we anticipate will provide attractive returns and cash flows. We continuously evaluate our capital plan and make changes as conditions warrant.

We have revised our timeline for completion of certain capital projects that are classified as construction-in-progress within *Property, plant and equipment, net* in the accompanying Consolidated Balance Sheets. The expected completion dates of these projects have been updated to more closely align with the expected timing of utilization by their respective producer customers as part of the just-in-time component of our capital program. We continue to believe all amounts capitalized will be recoverable as we expect these projects to be completed.

Other Capital Requirements and Strategic Actions

On January 3, 2017, MPC announced plans to significantly accelerate the dropdown of assets with an estimated $1.4 billion of MLP-eligible annual EBITDA to MPLX LP now expected to be completed in 2017, subject to requisite approvals and regulatory clearances, including tax, and market and other conditions. We expect these dropdowns to be valued consistent with recent industry precedent valuation multiples ranging between 7.0x and 9.0x EBITDA, subject to the MPLX LP conflicts committee review process and receipt of customary fairness opinions. We also expect the Partnership to finance the dropdown transactions with debt and equity in approximately equal proportions in the aggregate for all planned dropdown of assets. The equity financing is expected to be funded through MPLX LP common units issued to MPC. In conjunction with the completion of the dropdowns, MPC also expects to exchange its economic interests in our general partner, including incentive distribution rights, for newly issued MPLX LP common units. MPC would continue to retain control of the general partner following this exchange.

On February 6, 2017, we announced the formation of a strategic joint venture to support the development of Antero Resources extensive rich-gas position in the Marcellus Shale. The 50-50 joint venture with Antero Midstream will include the ongoing development of incremental gas processing, including three additional processing plants at the Sherwood Complex in West Virginia by the first quarter of 2018 and the ownership of 20,000 bpd of the newly constructed Hopedale III fractionation train and an option to invest in additional fractionation expansions at the Hopedale Complex in Ohio, subject to the production of incremental NGLs from the joint venture’s processing facilities. In connection with this transaction, the Partnership contributed approximately $134 million of assets currently under construction at the Sherwood Complex and Antero Midstream made an initial capital contribution of approximately $155 million.

On February 13, 2017, we also announced the acquisition of Ozark pipeline from Enbridge Ozark for approximately $220 million. The Ozark pipeline is a 433-mile, 22-inch crude oil pipeline originating in Cushing, Oklahoma and terminating in Wood River, Illinois, capable of transporting approximately 230,000 barrels per day. This purchase transaction is expected to close in the first quarter of 2017 and will be funded with cash on hand.

On February 15, 2017, we also acquired a joint venture interest in the Bakken Pipeline system from ETP and SXL. MPLX LP contributed $500 million of the $2 billion purchase price. The Bakken Pipeline system is currently expected to deliver in excess of 470,000 barrels per day of crude oil from the Bakken/ Three Forks production area in North Dakota to the Midwest through Patoka, Illinois and ultimately to the Gulf Coast. MPLX LP funded this acquisition with cash on hand.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2016:

(In millions)	Total	2017	2018-2019	2020-2021	Later Years
Bank revolving credit facility[1]	$ 16	$ 4	$ 8	$ 4	$ —
Term loan[1]	267	6	261	—	—
Long-term debt[1]	6,300	221	442	442	5,195
Capital lease obligations	9	1	3	5	—
Operating lease and long-term storage agreements[2]	302	61	93	72	76
Purchase obligations:					
Contracts to acquire property, plant & equipment	588	556	32	—	—
Other contracts	42	38	1	1	2
Total purchase obligations[3]	630	594	33	1	2
Natural gas purchase obligations[4]	103	19	34	33	17
SMR liability[5]	228	17	34	34	143
Transportation and terminalling[6]	608	46	123	122	317
Other long-term liabilities reflected on the Consolidated Balance Sheets:					
Other liabilities[7]	26	26	—	—	—
AROs[8]	25	—	—	—	25
Total contractual cash obligations	$8,514	$995	$1,031	$713	$5,775

(1) Amounts represent outstanding borrowings at December 31, 2016, plus any commitment and administrative fees and interest.

(2) Amounts relate primarily to a long-term propane storage agreement and our office and vehicle leases.

(3) Represents purchase orders and contracts related to the purchase or build out of property, plant and equipment. Purchase obligations exclude current and long-term unrealized losses on derivative instruments included on the accompanying Consolidated Balance Sheets, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts are generally 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.

(4) Natural gas purchase obligations consist primarily of a purchase agreement with a producer in our Southern Appalachia Operations. The contract provides for the purchase of keep-whole volumes at a specific price and is a component of a broader regional arrangement. The contract price is designed to share a portion of the frac spread with the producer and as a result, the amounts reflected for the obligation exceed the cost of purchasing the keep-whole volumes at a market price. The contract is considered an embedded derivative (see Item 8. Financial Statements and Supplementary Data—Note 16 for the fair value of the frac spread sharing component). We use the estimated future frac spreads as of December 31, 2016 for calculating this obligation. The counterparty to the contract has the option to renew the gas purchase agreement and the related keep-whole processing agreement for two successive five-year terms after 2022, which is not included in the natural gas purchase obligations line item.

(5) Represents amounts due under a product supply agreement (see Item 8. Financial Statements and Supplementary Data—Note 23 for further discussion of the product supply agreement).

(6) Represents transportation and terminalling agreements that obligate us to minimum volume, throughput or payment commitments over the terms of the agreements, which will range from three to ten years. We expect to pass any minimum payment commitments through to producer customers. Minimum fees due under transportation agreements do not include potential fee increases as required by FERC.

(7) Includes the payable for Class B units recorded in connection with the MarkWest Merger (see Item 8. Financial Statements and Supplementary Data—Note 4 for further discussion).

(8) Excludes estimated accretion expense of $29 million. The total amount to be paid is approximately $54 million.

In addition to the obligations included in the table above, we have an omnibus agreement and employee services agreements with MPC. The omnibus agreement with MPC addresses our payment of a fixed annual fee to MPC for the provision of executive management services by certain executive officers of our general partner and our reimbursement to MPC for the provision of certain general and administrative services to us. The omnibus agreement remains in full force and effect as long as MPC controls our general partner. Under the omnibus agreement, we pay to MPC in equal monthly installments an annual amount of approximately $51 million in 2016 for the provision of services by MPC, such as information technology, engineering, legal, accounting, treasury, human resources and other administrative services. The annual amount includes a fixed annual fee of approximately $12 million for the provision of certain executive management services by certain officers of our general partner.

We also pay MPC additional amounts based on the costs actually incurred by MPC in providing other services, except for the portion of the amount attributable to engineering services, which is based on the amounts actually incurred by MPC and its affiliates plus six percent of such costs. In addition, we are obligated to reimburse MPC for any out-of-pocket costs and expenses incurred by MPC on our behalf.

We have four employee services agreements with MPC. Two of the employee services agreements with MPC were entered into effective October 1, 2012, under which we agreed to reimburse MPC for the provision of certain operational and management services to us in support of our pipelines, barge dock, butane cavern and tank farms within the L&S segment. Effective December 28, 2015, we entered into an additional employee services agreement with MPC, which requires that we reimburse MPC for certain operational and management services to us in support of our G&P segment and certain of our other operations. Lastly, we are party to an employee services agreement with MPC dated as of January 1, 2015, pursuant to which HSM reimburses MPC for employee benefit expenses along with certain operation and management services provided in support of HSM's areas of operation. The agreement is effective until December 31, 2019. We incurred $359 million of expenses under the employee services agreements for 2016.

Off-Balance Sheet Arrangements

As of December 31, 2016, we have not entered into any transactions, agreements or other arrangements that would result in off-balance sheet liabilities.

Forward-looking Statements

Our opinions concerning liquidity and capital resources and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance (as measured by various factors, including cash provided by operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and future credit ratings by rating agencies. The discussion of liquidity and capital resources above also contains forward-looking statements regarding expected capital spending. The forward-looking statements about our capital budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include negative capital market conditions, including a persistence or increase of the current yield on common units, which is higher than historical yields, adversely affecting the Partnership's ability to meet its distribution growth guidance; the time, costs and ability to obtain regulatory or other approvals and consents and otherwise consummate the strategic initiatives discussed herein and other proposed transactions; the satisfaction or waiver of conditions in the agreements governing the strategic initiatives discussed herein and other proposed transactions; our ability to achieve the strategic and other objectives related to the strategic initiatives and transactions discussed herein, including the dropdowns proposed by MPC, the joint venture with Antero Midstream Partners LP, the Ozark pipeline, and other proposed transactions; adverse changes in laws including with respect to tax and regulatory matters; inability to agree with respect to the timing of and value attributed to assets identified for dropdown; the adequacy of the Partnership's capital resources and liquidity, including, but not limited to, availability of sufficient cash flow to pay distributions, and the ability to successfully execute its business plans and growth strategy; continued/further volatility in and/or degradation of market and industry conditions; changes to the expected construction costs and timing of projects; completion of midstream infrastructure by competitors; disruptions due to equipment interruption or failure, including electrical shortages and power grid failures; the suspension, reduction or termination of MPC's obligations under the Partnership's commercial agreements; modifications to earnings and distribution growth objectives; the level of support from MPC, including dropdowns, alternative financing arrangements, taking equity units, and other methods of sponsor support, as a result of the capital allocation needs of the enterprise as a whole and its ability to provide support on commercially reasonable terms; compliance with federal and state environmental, economic, health and safety, energy and other policies and regulations and/or enforcement actions initiated thereunder; changes to the Partnership's capital budget; prices of and demand for natural gas, NGLs, crude oil and refined products, delays in obtaining necessary third-party approvals and governmental permits, changes in labor, material and equipment costs and availability, planned and unplanned outages, the delay of, cancellation of or failure to implement planned capital projects, project overruns, disruptions or interruptions of our operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations. These factors, among others, could cause actual results to differ materially from those set forth in the forward- looking statements. For additional information on forward-looking statements and risks that can affect our business, see "Disclosures Regarding Forward-Looking Statements" and Item 1A. Risk Factors in this Annual Report on Form 10-K.

Effects of Inflation

Inflation did not have a material impact on our results of operations for the years ended December 31, 2016, 2015 or 2014. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire, build or replace property, plant and equipment. It may also increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and expect to continue to pass along all or a portion of increased costs to our customers in the form of higher fees.

TRANSACTIONS WITH RELATED PARTIES

MPC owns our general partner and an approximate 23.5 percent limited partner interest (including the Class B units on an as-converted basis) in us as of February 13, 2017 and all of our incentive distribution rights.

Excluding revenues attributable to volumes shipped by MPC under joint tariffs with third parties that are treated as third-party revenues for accounting purposes, MPC accounted for 30 percent, 79 percent and 90 percent of our total revenues and other income for 2016, 2015 and 2014, respectively. We provide crude oil and product pipeline transportation services based on regulated tariff rates and storage services and inland marine transportation based on contracted rates.

Of our total costs and expenses, MPC accounted for 20 percent, 35 percent and 41 percent for 2016, 2015 and 2014, respectively. MPC performed certain services for us related to information technology, engineering, legal, accounting, treasury, human resources and other administrative services.

We believe that transactions with related parties were conducted under terms comparable to those with unrelated parties. For further discussion of agreements and activity with MPC and related parties see Item 1. Business—Our Transportation and Storage Services Agreements with MPC,—Operating and Management Services Agreements with MPC and Third Parties,—Other Agreements with MPC and Item 8. Financial Statements and Supplementary Data—Note 6.

ENVIRONMENTAL MATTERS AND COMPLIANCE COSTS

We are subject to extensive federal, state and local environmental laws and regulations. These laws, which change frequently, regulate the discharge of materials into the environment or otherwise relate to protection of the environment. Compliance with these laws and regulations may require us to remediate environmental damage from any discharge of hazardous, petroleum or chemical substances from our facilities or require us to install additional pollution control equipment on our equipment and facilities. Our failure to comply with these or any other environmental or safety-related regulations could result in the assessment of administrative, civil or criminal penalties, the imposition of investigatory and remedial liabilities, and the issuance of injunctions that may subject us to additional operational constraints.

Future expenditures may be required to comply with the Clean Air Act and other federal, state and local requirements for our various facilities. The impact of these legislative and regulatory developments, if enacted or adopted, could result in increased compliance costs and additional operating restrictions on our business, each of which could have an adverse impact on our financial position, results of operations and liquidity. MPC will indemnify us for certain of these costs under the omnibus agreement.

If these expenditures, as with all costs, are not ultimately reflected in the fees and tariff rates we receive for our services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including, but not limited to, the age and location of its operating facilities. Our environmental expenditures for each of the past three years were:

(In millions)	2016	2015	2014
Capital	$10	$ 2	$ 2
Percent of total capital expenditures	1%	1%	3%
Compliance:			
Operating and maintenance	$75	$22	$22
Remediation[(1)]	2	2	2
Total	$77	$24	$24

(1) These amounts include spending charged against remediation reserves, where permissible, but exclude non-cash accruals for environmental remediation.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We believe we comply with all legal requirements regarding the environment, but since not all of them are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

Our environmental capital expenditures are expected to approximate $3 million in 2017. Actual expenditures may vary as the number and scope of environmental projects are revised as a result of improved technology or changes in regulatory requirements and could increase if additional projects are identified or additional requirements are imposed. The amount of expenditures in 2017 is also dependent upon the resolution of the matters described in Item 3—Legal Proceedings, which may require us to complete additional projects and increase our actual environmental capital and operating expenditures.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

The policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See Item 8 Financial Statements and Supplementary Data—Note 2 for additional information on these policies and estimates, as well as a discussion of additional accounting policies and estimates.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Acquisitions		
In accounting for business combinations, acquired assets and liabilities, noncontrolling interests, if any, and contingent consideration are recorded based on estimated fair values as of the date of acquisition. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence. Valuation techniques that maximize the use of observable inputs are favored. The excess or shortfall of the purchase price when compared to the fair value of the net tangible and identifiable intangible assets acquired, if any, and noncontrolling interests, if any, is recorded as	The fair value of assets, liabilities, including contingent consideration, and noncontrolling interests as of the acquisition date are often estimated using a combination of approaches, including the income approach, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate; the cost approach, which requires estimates of replacement costs and useful life and obsolescence estimates; and the market approach which uses market data and adjusts for entity-specific differences. Additionally, for customer contract intangibles we must estimate the expected life of the relationship with our customers on a reporting unit basis. The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.	If estimates or assumptions used to complete the purchase price allocation and estimate the fair value of acquired assets, liabilities and noncontrolling interests significantly differed from assumptions made, the allocation of purchase price between goodwill, intangibles, noncontrolling interests, equity method investments and property plant and equipment could significantly differ. Such a difference would impact future earnings through depreciation and amortization expense. In addition, if forecasts supporting the valuation of the intangibles or goodwill are not achieved, impairments could arise. Further, if customer relationships terminate prior to the expected useful life, we will be required to record a charge to operations to write-off any remaining unamortized balance of the intangible asset assigned to that customer. See Item 8. Financial Statements and Supplementary Data—Note 4 for additional information on the MarkWest Merger. That acquisition was completed effective December 4, 2015.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
goodwill or a bargain purchase gain, respectively. A significant amount of judgment is involved in estimating the individual fair values of property, plant and equipment, intangible assets, equity method investments, contingent consideration, other assets and liabilities and noncontrolling interests. We use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance. We adjust the preliminary purchase price allocation, as necessary, after the acquisition closing date through the end of the measurement period of up to one year as we finalize valuations for the assets acquired, liabilities assumed, and noncontrolling interest, if any.		
Impairment of Long-Lived Assets		
Management evaluates our long-lived assets, including intangibles, for impairment when certain events have taken place that indicate that the carrying value may not be recoverable from the expected undiscounted future cash flows. Qualitative and quantitative information is reviewed in order to determine if a triggering event has occurred or if an impairment indicator exists. If we determine that a triggering event has occurred we would complete a full impairment analysis. If we determine that the carrying value of a reporting unit is not recoverable, a loss is recorded for the difference between the fair value and the carrying value. We evaluate our property, plant and equipment and intangibles on at least a segment level and at lower levels where cash flows for specific assets can be identified, which generally is the plant level for our G&P segment, the pipeline system level for our L&S segment, and the customer	Management considers the volume of reserves dedicated to be processed by the asset and future NGL product and natural gas prices to estimate cash flows for each asset group. Management considers the expected net operating margin to be earned by customers for each customer contract intangible. Management uses discount rates commensurate with the risks involved for each asset considered. The amount of additional reserves developed by future drilling activity and expected net operating margin earned by customer depends, in part, on expected commodity prices. Projections of reserves, drilling activity, ability to renew contracts of significant customers, and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast. Management considered the	As of December 31, 2016, there were no indicators of impairment for any of our long-lived assets.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
relationship for our customer contract intangibles.	sustained reduction of commodity prices in forecasted cash flows.	
Impairment of Goodwill		
Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of November 30 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The first step of the evaluation is a qualitative analysis to determine if it is "more likely than not" that the carrying value of a reporting unit with goodwill exceeds its fair value. The additional quantitative steps in the goodwill impairment test may be performed if we determine that it is more likely than not that the carrying value is greater than the fair value.	Management performed a quantitative analysis as of November 30, 2016. We determined the fair value of our reporting units in both the G&P and L&S segments using the income and market approaches for our 2016 impairment analysis. This type of analysis requires us to make assumptions and estimates regarding industry and economic factors such as relevant commodity prices, contract renewals, and production volumes. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations. For the 2016 qualitative analysis, we analyzed the changes in the assumptions above in light of current economic conditions to determine if it was more likely than not that impairment exists. We looked at factors, including changes in the forecasted operating income and volumes for the three reporting units with goodwill, changes in the commodity price environment, changes in our per unit market value, changes in our peers' market value and changes in industry EBITDA multiples. Management is also required to make certain assumptions when identifying the reporting units and determining the amount of goodwill allocated to each reporting unit. The method of allocating goodwill resulting from the acquisitions involved	The Partnership recorded approximately $130 million of impairment expense related to charges recorded during the first and second quarters of the fiscal year. We recorded no impairment charge related to our annual impairment review of goodwill as of November 30, 2016. The fair value of the reporting units for our goodwill impairment analysis was determined based on applying the discounted cash flow method, which is an income approach, and the guideline public company method, which is a market approach. The discounted cash flow fair value estimate is based on known or knowable information at the measurement date. The significant assumptions that were used to develop the estimates of the fair values under the discounted cash flow method include management's best estimates of the expected future results and discount rates, which range from 7.8 percent to 14.5 percent. Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of the impairment tests will prove to be an accurate prediction of the future. As of December 31, 2016, the Partnership had five reporting units with goodwill: Marcellus ($1.8 billion), East Texas ($228

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
	estimating the fair value of the reporting units and allocating the purchase price for each acquisition to each reporting unit. Goodwill is then calculated for each reporting unit as the excess of the allocated purchase price over the estimated fair value of the net assets.	million), West Texas ($41 million), HSM ($11 million), and MPL ($105 million). Step 1 of the fourth quarter impairment analysis resulted in the fair value of the reporting units exceeding their carrying value by approximately 28 percent, 8 percent, 44 percent, 303 percent and 167 percent, respectively. An increase of 0.50 percent to the discount rate used to estimate the fair value of the reporting units would not have resulted in a goodwill impairment charge as of December 31, 2016. Our fourth quarter analysis resulted in a significant increase in the fair value of the reporting units as compared to the interim analyses performed during 2016. This increase was generally supported by an increase in our market capitalization of approximately 49 percent. Significant assumptions used to estimate the reporting units' fair value included estimates of future cash flows. If estimates for future cash flows, which are impacted primarily by commodity prices and producers' production plans, for the reporting units were to decline, the overall reporting units' fair value would decrease, resulting in potential goodwill impairment charges. Additionally, an increase in the cost of capital would result in a decrease in the fair value of the reporting units, causing their value to decline and goodwill to potentially be impaired.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Impairment of Equity Method Investments		
We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced a decline in value. When evidence of an other-than-temporary loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment should be recorded.	Our impairment assessment requires us to apply judgment in estimating future cash flows received from or attributable to our equity method investments. The primary estimates may include the expected volumes, the terms of related customer agreements and future commodity prices.	A fixed asset impairment analysis was performed during the second quarter for Ohio Condensate Company (OCC) resulting in an impairment charge of $96 million within OCC's financial statements. Approximately $58 million of the charge was attributable to the Partnership based on its 60 percent ownership of OCC and was recorded in *(Loss) income from equity method investments* on the accompanying Consolidated Statements of Income. Furthermore, to determine the potential equity method impairment charge, an impairment analysis in accordance with ASC Topic 323 was performed during the second quarter resulting in an additional impairment charge of approximately $31 million, recorded in *(Loss) income from equity method investments* on the accompanying Consolidated Statements of Income. For purposes of the second quarter impairment analysis, the fair value of OCC was determined based on applying the discounted cash flow method, which is an income approach, and the guideline public company method, which is a market approach. The significant assumptions used to estimate the fair value under the discounted cash flow method included management's best estimates of the expected results using a probability weighted average set of cash flow forecasts and using a discount rate of 11.2 percent. Fair value

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
		determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As such, the fair value of the OCC equity method investment and its underlying fixed assets represents a Level 3 measurement. As of December 31, 2016, Management determined that there were no material events or changes in circumstances that would indicate an other-than-temporary decline in our equity method investments.
Accounting for Risk Management Activities and Derivative Financial Instruments		
Our derivative financial instruments are recorded at fair value in the accompanying Consolidated Balance Sheets. Changes in fair value and settlements are reflected in our earnings in the accompanying Consolidated Statements of Income as gains and losses related to revenue, purchased product costs, and cost of revenues.	When available, quoted market prices or prices obtained through external sources are used to determine a financial instrument's fair value. The valuation of Level 2 financial instruments is based on quoted market prices for similar assets and liabilities in active markets and other inputs that are observable. However, for other financial instruments for which quoted market prices are not available, the fair value is based on inputs that are largely unobservable such as option volatilities and NGL prices that are interpolated and extrapolated due to inactive markets. These instruments are classified as Level 3 under the fair value hierarchy. All fair value measurements are appropriately adjusted for non-performance risk.	If the assumptions used in the pricing models for our Level 2 and 3 financial instruments are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different and we may be exposed to unrealized losses or gains that could be material. A 10 percent difference in our estimated fair value of Level 2 and 3 derivatives at December 31, 2016 would have affected income before income taxes by approximately $6 million for the year ended December 31, 2016.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Accounting for Significant Embedded Derivative Instruments		
Identifying and embedded derivatives is complex and requires significant judgment. We have a gas purchase agreement with a producer customer in which we are required to purchase natural gas based on a complex formula designed to share some of the frac spread with the producer customer, through December 31, 2022. Additionally, we have a keep-whole gas processing agreement with the same producer customer. For accounting purposes, these two contracts have been aggregated into a single contract, and are evaluated together. The agreements have primary terms that expire on December 31, 2022 and contain two successive term-extending options under which the producer customer can extend the purchase and processing agreements an additional five years each. Neither contract may be extended without an election to extend the other contract. The feature of the gas purchase contract to purchase gas based on a complex formula designed to share some of the frac spread with the producer customer and the option to extend both contracts have been identified as a single embedded derivative ("Natural Gas Embedded Derivative") that requires a complex valuation based on significant judgment. The option to extend the contracts is part of the embedded feature and thus is required to be considered in the valuation of the embedded derivative. We are required to make a significant judgment about the probability that the option would be exercised when determining the value of the embedded derivative.	We carry the Natural Gas Embedded Derivative at fair value with changes in fair value recognized in income each period. The valuation requires significant judgment when forming the assumptions used. Third-party forward curves for certain commodity prices utilized in the valuation do not extend through the term of the arrangement. Thus, pricing is required to be extrapolated for those periods. We utilize multiple cash flow techniques to extrapolate NGL pricing. Due to the illiquidity of future markets, we do not believe one method is more indicative of fair value than the other methods. The fair value is also appropriately adjusted for non-performance risk each period. We evaluated various factors in order to determine the probability that the term-extending options would be exercised by the producer customer, such as estimates of future gas reserves in the region, the competitive environment in which the producer customer operates, the commodity price environment and the producer customer's business strategy. As of December 31, 2016, we have estimated the probability that the producer customer will exercise its option to extend the agreements for the first renewal period is 50 percent, and for the second renewal period is 75 percent based on the inherent uncertainty of the variables that would impact its decision.	The Natural Gas Embedded Derivative is an instrument that is not exchange-traded. The valuation of the instrument is complex and requires significant judgment. The inputs used in the valuation model require specialized knowledge, as NGL price curves do not exist for the entire term of the arrangement. The valuation is sensitive to NGL and natural gas future price curves. Holding the natural gas curves constant, a 10 percent increase (decrease) in NGL price curves causes an 18 percent increase (decrease) in the liability as of December 31, 2016. Holding the NGL curves constant, a 10 percent increase (decrease) in the natural gas curves causes a 6 percent (decrease) increase in the liability as of December 31, 2016. The determination of the fair value of the option to extend is based on our judgment about the probability of the producer customer exercising the extension. If it were determined that the probability of exercise was 25 percent for the first renewal period and 50 percent for the second renewal period as of December 31, 2016, the liability would be reduced by 23 percent. If it were determined that the probability of exercise was 75 percent for the first renewal period and 100 percent for the second renewal period as of December 31, the liability would be increased by 88 percent. See Item 8. Financial Statements and Supplementary Data—Note 15 for more information related to the Natural Gas Embedded Derivative.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Variable Interest Entities		
We evaluate all legal entities in which we hold an ownership or other pecuniary interest to determine if the entity is a VIE. Our interests in a VIE are referred to as variable interests. Variable interests can be contractual, ownership or other pecuniary interests in an entity that change with changes in the fair value of the VIE's assets. When we conclude that we hold an interest in a VIE we must determine if we are the entity's primary beneficiary. A primary beneficiary is deemed to have a controlling financial interest in a VIE. This controlling financial interest is evidenced by both (a) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses that could potentially be significant to the VIE or the right to receive benefits that could potentially be significant to the VIE. We consolidate any VIE when we determine that we are the primary beneficiary. We must disclose the nature of any interests in a VIE that is not consolidated.	Significant judgment is exercised in determining that a legal entity is a VIE and in evaluating our interest in a VIE. We use primarily a qualitative analysis to determine if an entity is a VIE. We evaluate the entity's need for continuing financial support; the equity holder's lack of a controlling financial interest; and/or if an equity holder's voting interests are disproportionate to its obligation to absorb expected losses or receive residual returns. We evaluate our interests in a VIE to determine whether we are the primary beneficiary. We use a primarily qualitative analysis to determine if we are deemed to have a controlling financial interest in the VIE, either on a standalone basis or as part of a related party group. We continually monitor our interests in legal entities for changes in the design or activities of an entity and changes in our interests, including our status as the primary beneficiary to determine if the changes require us to revise our previous conclusions.	MarkWest Utica EMG, Ohio Condensate and Jefferson Dry Gas are VIEs; however, we are not considered to be the primary beneficiary. As a result, they are accounted for under the equity method. Changes in the design or nature of the activities of these entities, or our involvement with an entity, may require us to reconsider our conclusions on the entity's status as a VIE and/or our status as the primary beneficiary. Such reconsideration requires significant judgment and understanding of the organization. This could result in the deconsolidation or consolidation of the affected subsidiary, which would have a significant impact on our financial statements. Ohio Gathering is a subsidiary of MarkWest Utica EMG and is a VIE. If we were to consolidate MarkWest Utica EMG, Ohio Gathering would need to be assessed for consolidation or deconsolidation. We account for our ownership interest in Centrahoma and MarkWest Pioneer under the equity method and have determined that these entities are not VIEs. However, changes in the design or nature of the activities of either entities may require us to reconsider our conclusions. Such reconsideration would require the identification of the variable interests in the entity and a determination on which party is the entity's primary beneficiary. If an equity investment were considered a VIE and we were determined to be the primary

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
		beneficiary, the change could cause us to consolidate the entity. The consolidation of an entity that is currently accounted for under the equity method could have a significant impact on our financial statements. See Item 8. Financial Statements and Supplementary Data—Note 5 for more information on our other investments.
Contingent Liabilities		
We accrue contingent liabilities for legal actions, claims, litigation, environmental remediation, tax deficiencies related to operating taxes and third-party indemnities for specified tax matters when such contingencies are both probable and can be reasonably estimated.	We regularly assess these estimates in consultation with legal counsel to consider resolved and new matters, material developments in court proceedings or settlement discussions, new information obtained as a result of ongoing discovery and past experience in defending and settling similar matters. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on degree of responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their interpretation, additional information on the extent and nature of site contamination and improvements in technology.	An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss. For additional information on contingent liabilities, see Item 8. Financial Statements and Supplementary Data—Note 23.

Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the FASB that we adopt as of the specified effective date. If not discussed in Item 8. Financial Statements and Supplementary Data—Note 3, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on our financial statements upon adoption.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk includes the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity price changes and, to a lesser extent, interest rate changes and non-performance by our customers and counterparties.

Commodity Price Risk

NGL and natural gas prices are volatile and are impacted by changes in fundamental supply and demand, as well as market uncertainty, availability of NGL transportation and fractionation capacity and a variety of additional factors that are beyond the Partnership's control. Our profitability is directly affected by prevailing commodity prices primarily as a result of processing or conditioning at our own or third-party processing plants, purchasing and selling or gathering and transporting volumes of natural gas at index-related prices and the cost of third-party transportation and fractionation services. To the extent that commodity prices influence the level of natural gas drilling by our producer customers, such prices also affect profitability. To protect us financially against adverse price movements and to maintain more stable and predictable cash flows so that we can meet our cash distribution objectives, debt service and capital plans, we execute a strategy governed by our risk management policy. We have a committee comprised of senior management that oversees risk management activities, continually monitors the risk management program and adjusts our strategy as conditions warrant. We enter into certain derivative contracts to reduce the risks associated with unfavorable changes in the prices of natural gas, NGLs and crude oil. Derivative contracts utilized are swaps traded on the OTC market and fixed price forward contracts. The risk management policy does not allow us to take speculative positions with our derivative contracts.

To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have entered into derivative financial instruments relating to the future price of NGLs and crude oil. We currently manage the majority of our NGL price risk using direct product NGL derivative contracts. We enter into NGL derivative contracts when adequate market liquidity exists and future prices are satisfactory. A small portion of our NGL price exposure is managed by using crude oil contracts. Based on our current volume forecasts, we expect the majority of our derivative positions used to manage our future commodity price exposure will be direct product NGL derivative contracts.

To mitigate our cash flow exposure to fluctuations in the price of natural gas, we primarily utilize derivative financial instruments relating to the future price of natural gas and take into account the partial offset of our long and short natural gas positions resulting from normal operating activities.

As a result of our current derivative positions, we believe that we have mitigated a portion of our expected commodity price risk through the fourth quarter of 2017. We would be exposed to additional commodity risk in certain situations such as if producers under-deliver or over-deliver products or if processing facilities are operated in different recovery modes. In the event that we have derivative positions in excess of the product delivered or expected to be delivered, the excess derivative positions may be terminated.

Management conducts a standard credit review on counterparties to derivative contracts, and we have provided the counterparties with a guaranty as credit support for our obligations. A separate agreement with certain counterparties allows MarkWest Liberty Midstream to enter into derivative positions without posting cash collateral. We use standardized agreements that allow for offset of certain positive and negative exposures in the event of default or other terminating events, including bankruptcy.

Outstanding Derivative Contracts

The following tables provide information on the volume of our derivative activity for positions related to long liquids price risk at December 31, 2016, including the weighted-average prices ("WAVG"):

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2017	100	$52.10	$ (152)

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2017	814	$ 2.93	$ 149

Ethane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2017	42,000	$ 0.26	$ (433)

Propane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2017	74,370	$ 0.56	$(3,173)

IsoButane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2017	5,063	$ 0.71	$ (314)

Normal Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2017	22,862	$ 0.71	$(1,051)

Natural Gasoline Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2017	31,628	$ 1.10	$(1,208)

The following table provides information on the derivative positions related to long liquids price risk as of February 13, 2017 that we have entered into subsequent to December 31, 2016, including the WAVG:

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)
2017 (Apr.—Dec.)	112	$56.40

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)
2017 (Apr.—Dec.)	1,141	$ 3.11

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)
2018	2,542	$ 2.78

Ethane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)
2017 (Apr.—Dec.)	14,143	$ 0.28

Propane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)
2017 (Apr.—Dec.)	49,180	$ 0.67

Propane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)
2018	16,925	$ 0.64

IsoButane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)
2017 (Apr.—Dec.)	7,206	$ 0.87

IsoButane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)
2018	1,655	$ 0.80

Normal Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)
2017 (Apr.—Dec.)	8,591	$ 0.85

Normal Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)
2018	4,595	$ 0.75

Natural Gasoline Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)
2017 (Apr.—Dec.)	8,494	$ 1.21

Natural Gasoline Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)
2018	3,089	$ 1.18

We have a commodity contract with a producer customer in the Southern Appalachian region that creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The commodity contract is a component of a broader regional arrangement that also includes a keep-whole processing agreement. For accounting purposes, these contracts have been aggregated into a single contract and are evaluated together. In February 2011, we executed agreements with the producer customer to extend the commodity contract and the related processing agreement from March 31, 2015 to December 31, 2022, with the producer customer's option to extend the agreement for two successive five year terms through December 31, 2032. The purchase of gas at prices based on the frac spread and the option to extend the agreements have been identified as a single embedded derivative, which is recorded at fair value. The probability of renewal is determined based on extrapolated pricing curves, a review of the overall expected favorability of the contracts based on such pricing curves, and assumptions about the counterparty's potential business strategy decision points that may exist at the time the counterparty would elect whether to renew the contracts. The changes in fair value of this embedded derivative are based on the difference between the contractual and index pricing, the probability of the producer customer exercising its option to extend and the estimated favorability of these contracts compared to current market conditions. The changes in fair value are recorded in earnings through Purchased product costs in the Consolidated Statements of Income. As of December 31, 2016, the estimated fair value of this contract was a liability of $54 million.

During the years ended December 31, 2016 and 2015, the Partnership had a commodity contract that allowed for the Partnership to fix a component of the utilities cost to an index price on electricity at a plant location in the Southwest Operations which expired as of December 31, 2016. Changes in the fair value of the derivative component of this contract were recognized as *Cost of revenues* in the Consolidated Statements of Income. As of December 31, 2015, the estimated fair value of this contract was a liability of $1 million.

Interest Rate Risk

Sensitivity analysis of the effect of a hypothetical 100-basis-point change in interest rates on long-term debt, excluding capital leases, is provided in the following table. Fair value of cash and cash equivalents, receivables, accounts payable and accrued interest approximate carrying value and are relatively insensitive to changes in interest rates due to the short-term maturity of the instruments. Accordingly, these instruments are excluded from the table.

(In millions)	Fair Value as of December 31, 2016[(1)]	Change in Fair Value[(2)]	Change in income before income taxes for the Year Ended December 31, 2016[(3)]
Long-term debt			
Fixed-rate	$4,703	$304	N/A
Variable-rate	$ 250	N/A	$ 5

(1) Fair value was based on market prices, where available, or current borrowing rates for financings with similar terms and maturities.

(2) Assumes a 100-basis-point decrease in the weighted average yield-to-maturity at December 31, 2016.

(3) Assumes a 100-basis-point change in interest rates. The change to net income was based on the weighted average balance of all outstanding variable-rate debt for the year ended December 31, 2016.

At December 31, 2016, our portfolio of long-term debt consisted of fixed-rate instruments and variable-rate instruments under our term loan facility. The fair value of our fixed-rate debt is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value. Interest rate fluctuations generally do not impact the fair value of borrowings under our bank revolving credit or term loan facilities, but may affect our results of operations and cash flows. As of December 31, 2016, we did not have any financial derivative instruments to hedge the risks related to interest rate fluctuations; however, we continually monitor the market and our exposure and may enter into these agreements in the future.

Credit Risk

We are subject to risk of loss resulting from non-payment by our customers to whom we provide services or sell natural gas or NGLs. We believe that certain contracts would allow us to pass those losses through to our customers, thus reducing our risk, when we are selling NGLs and acting as our producer customers' agent. Our credit exposure related to these customers is represented by the value of our trade receivables. Where exposed to credit risk, we analyze the customer's financial condition prior to entering into a transaction or agreement, establish credit terms and monitor the appropriateness of these terms on an ongoing basis. In the event of a customer default, we may sustain a loss and our cash receipts could be negatively impacted.

We are subject to risk of loss resulting from non-payment or non-performance by the counterparties to our derivative contracts. Our credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value at the reporting date. These outstanding instruments expose us to credit loss in the event of non-performance by the counterparties to the agreements. Should the creditworthiness of one or more of our counterparties decline, our ability to mitigate non-performance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted. This counterparty credit risk does not apply to our embedded derivatives as the overall values are liabilities.

Item 8. Financial Statements and Supplementary Data

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Management's Responsibilities for Financial Statements

The accompanying consolidated financial statements of MPLX LP and its subsidiaries (the "Partnership") are the responsibility of management of the Partnership's general partner, MPLX GP LLC, and have been prepared in conformity with accounting principles generally accepted in the United States of America. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

MPLX GP LLC seeks to assure the objectivity and integrity of the Partnership's financial records by careful selection of its managers, by organizational arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The MPLX GP LLC Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit Committee. This committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

/s/ Gary R. Heminger	/s/ Pamela K.M. Beall	/s/ Paula L. Rosson
Gary R. Heminger *Chairman of the Board of Directors* *and Chief Executive Officer* *of MPLX GP LLC* *(the general partner of MPLX LP)*	*Pamela K.M. Beall* *Director, Executive Vice President* *and Chief Financial Officer* *of MPLX GP LLC* *(the general partner of MPLX LP)*	*Paula L. Rosson* *Senior Vice President* *and Chief Accounting Officer* *of MPLX GP LLC* *(the general partner of MPLX LP)*

Management's Report on Internal Control over Financial Reporting

MPLX LP's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended). An evaluation of the design and effectiveness of our internal control over financial reporting, based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our chief executive officer and chief financial officer. Based on the results of this evaluation, MPLX LP's management concluded that its internal control over financial reporting was effective as of December 31, 2016.

The effectiveness of MPLX LP's internal control over financial reporting as of December 31, 2016 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Gary R. Heminger	/s/ Pamela K.M. Beall
Gary R. Heminger *Chairman of the Board of Directors* *and Chief Executive Officer* *of MPLX GP LLC* *(the general partner of MPLX LP)*	*Pamela K.M. Beall* *Director, Executive Vice President* *and Chief Financial Officer* *of MPLX GP LLC* *(the general partner of MPLX LP)*

Report of Independent Registered Public Accounting Firm

To the Partners of MPLX LP and the Board of Directors of MPLX GP LLC

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of equity and of cash flows present fairly, in all material respects, the financial position of MPLX LP and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP

Toledo, Ohio
February 24, 2017

MPLX LP
Consolidated Statements of Income

(In millions, except per unit data)	2016	2015	2014
Revenues and other income:			
Service revenue	$ 958	$ 130	$ 70
Service revenue—related parties	603	593	662
Rental income	298	20	—
Rental income—related parties	114	101	15
Product sales	572	36	—
Product sales—related parties	11	1	—
Gain on sale of assets	1	—	—
(Loss) income from equity method investments	(74)	3	—
Other income	6	6	6
Other income—related parties	101	71	40
Total revenues and other income	2,590	961	793
Costs and expenses:			
Cost of revenues (excludes items below)	354	225	228
Purchased product costs	448	20	—
Rental cost of sales	53	5	1
Purchases—related parties	316	166	153
Depreciation and amortization	546	116	75
Impairment expense	130	—	—
General and administrative expenses	193	118	81
Other taxes	43	13	10
Total costs and expenses	2,083	663	548
Income from operations	507	298	245
Related party interest and other financial costs	1	—	—
Interest expense (net of amounts capitalized of $28 million, $5 million, and $1 million, respectively)	210	35	4
Other financial costs	50	13	1
Income before income taxes	246	250	240
(Benefit) provision for income taxes	(12)	1	1
Net income	258	249	239
Less: Net income attributable to noncontrolling interests	2	1	57
Less: Net income attributable to Predecessor	23	92	61
Net income attributable to MPLX LP	233	156	121
Less: Preferred unit distributions	41	—	—
Less: General partner's interest in net income attributable to MPLX LP	191	57	6
Limited partners' interest in net income attributable to MPLX LP	$ 1	$ 99	$ 115
Per Unit Data (See Note 7)			
Net income attributable to MPLX LP per limited partner unit:			
Common—basic	$ —	$ 1.23	$ 1.55
Common—diluted	—	1.22	1.55
Subordinated—basic and diluted	—	0.11	1.50
Weighted average limited partner units outstanding:			
Common—basic	331	79	37
Common—diluted	338	80	37
Subordinated—basic and diluted	—	18	37
Cash distributions declared per limited partner common unit	$2.0500	$1.8200	$1.4100

The accompanying notes are an integral part of these consolidated financial statements.

MPLX LP
Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 234	$ 43
Receivables, net	297	245
Receivables—related parties	122	187
Inventories	54	51
Other current assets	33	50
Total current assets	740	576
Equity method investments	2,467	2,458
Property, plant and equipment, net	10,730	9,997
Intangibles, net	492	466
Goodwill	2,199	2,570
Long-term receivables—related parties	4	25
Other noncurrent assets	14	12
Total assets	$16,646	$16,104
Liabilities		
Current liabilities:		
Accounts payable	$ 123	$ 91
Accrued liabilities	228	187
Payables—related parties	75	54
Deferred revenue	2	—
Deferred revenue—related parties	34	32
Accrued property, plant and equipment	132	168
Accrued taxes	33	27
Accrued interest payable	53	54
Other current liabilities	24	12
Total current liabilities	704	625
Long-term deferred revenue	12	4
Long-term deferred revenue—related parties	15	9
Long-term debt	4,422	5,255
Deferred income taxes	5	378
Deferred credits and other liabilities	169	166
Total liabilities	5,327	6,437
Commitments and contingencies (see Note 23)		
Redeemable preferred units	1,000	—
Equity		
Common unitholders—public (271 million and 240 million units issued and outstanding)	8,086	7,691
Class B unitholders (4 million and 8 million units issued and outstanding)	133	266
Common unitholder—MPC (86 million and 57 million units issued and outstanding)	1,069	465
General partner—MPC (7 million units issued and outstanding)	1,013	819
Equity of Predecessor	—	413
Total MPLX LP partners' capital	10,301	9,654
Noncontrolling interest	18	13
Total equity	10,319	9,667
Total liabilities, preferred units and equity	$16,646	$16,104

The accompanying notes are an integral part of these consolidated financial statements.

MPLX LP
Consolidated Statements of Cash Flows

(In millions)	2016	2015	2014
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income	$ 258	$ 249	$ 239
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization of deferred financing costs	46	5	1
Depreciation and amortization	546	116	75
Impairment expense	130	—	—
Deferred income taxes	(17)	1	—
Asset retirement expenditures	(5)	(1)	(2)
Gain on disposal of assets	(1)	—	—
Loss (income) from equity method investments	74	(3)	—
Distributions from unconsolidated affiliates	148	15	—
Changes in:			
Current receivables	(52)	(29)	2
Inventories	(8)	1	1
Change in fair value of derivatives	43	(6)	—
Current accounts payable and accrued liabilities	100	2	1
Receivables from / liabilities to related parties	6	(22)	15
All other, net	20	12	2
Net cash provided by operating activities	1,288	340	334
Investing activities:			
Additions to property, plant and equipment	(1,206)	(288)	(141)
Acquisitions, net of cash acquired	—	(1,218)	—
Investments—loans to (from) related parties	77	(77)	—
Disposal of assets	1	—	—
Investments in unconsolidated affiliates	(87)	(14)	—
All other, net	3	(2)	4
Net cash used in investing activities	(1,212)	(1,599)	(137)
Financing activities:			
Long-term debt—borrowings	434	1,490	1,160
—repayments	(1,312)	(1,441)	(526)
Related party debt—borrowings	2,532	301	—
—repayments	(2,540)	(293)	—
Debt issuance costs	—	(11)	(3)
Net proceeds from equity offerings	792	1	230
Issuance of redeemable preferred units	984	—	—
Issuance of units in MarkWest Merger	—	169	—
Contributions from MPC—MarkWest Merger	—	1,230	—
Distributions to preferred unitholders	(25)	—	—
Distributions to unitholders and general partner	(845)	(158)	(103)
Distributions to noncontrolling interests	(3)	(1)	(47)
Contributions from noncontrolling interests	6	—	—
Consideration payment to Class B unitholders	(25)	—	—
Contribution from MPC	225	—	—
Distributions related to purchase of additional interest in Pipe Line Holdings	—	(12)	(910)
Distributions to MPC from Predecessor	(104)	—	(25)
All other, net	(4)	—	—
Net cash provided by (used in) financing activities	115	1,275	(224)
Net increase in cash and cash equivalents	191	16	(27)
Cash and cash equivalents at beginning of period	43	27	54
Cash and cash equivalents at end of period	$ 234	$ 43	$ 27

The accompanying notes are an integral part of these consolidated financial statements.

MPLX LP
Consolidated Statements of Equity

(In millions)	Partnership: Common Unitholders Public	Partnership: Class B Unitholders Public	Partnership: Common Unitholder MPC	Partnership: Subordinated Unitholder MPC	Partnership: General Partner MPC	Noncontrolling Interest	Equity of Predecessor	Total
Balance at December 31, 2013	$ 412	$ —	$ 57	$ 209	$ (32)	$ 468	$ 285	$ 1,399
Purchase/contribution of additional interest in Pipe Line Holdings	—	—	200	—	(638)	(472)	—	(910)
Equity offering, net of issuance costs	221	—	—	—	9	—	—	230
Net income	31	—	27	58	5	57	61	239
Distributions to MPC from Predecessor	—	—	—	—	—	—	(25)	(25)
Distributions to unitholders and general partner	(26)	—	(23)	(50)	(4)	—	—	(103)
Distributions to noncontrolling interest retained by MPC	—	—	—	—	—	(47)	—	(47)
Equity-based compensation	1	—	—	—	—	—	—	1
Balance at December 31, 2014	639	—	261	217	(660)	6	321	784
Purchase of additional interest in Pipe Line Holdings	—	—	—	—	(6)	(6)	—	(12)
Contributions from MPC—MarkWest Merger	—	—	—	—	1,280	—	—	1,280
Issuance of units under ATM program	1	—	—	—	—	—	—	1
Net income	15	—	36	48	57	1	92	249
Distributions to unitholders and general partner	(40)	—	(52)	(45)	(21)	—	—	(158)
Distributions to noncontrolling interests	—	—	—	—	—	(1)	—	(1)
Subordinated unit conversion			220	(220)				—
Equity-based compensation	17	—	—	—	—	—	—	17
Deferred income tax impact from changes in equity	(1)	—	—	—	—	—	—	(1)
Issuance of units in MarkWest Merger	7,060	266	—	—	169	—	—	7,495
Noncontrolling interest assumed in MarkWest Merger	—	—	—	—	—	13	—	13
Balance at December 31, 2015	7,691	266	465	—	819	13	413	9,667
Distributions to MPC from Predecessor	—	—	—	—	—	—	(104)	(104)
Contribution from MPC	—	—	84	—	141	—	—	225
Contribution of MarkWest Hydrocarbon from MPC	—	—	—	—	(188)	—	—	(188)
Distribution of MarkWest Hydrocarbon to MPC	—	—	—	—	563	—	—	563
Issuance of units under ATM Program	776	—	—	—	16	—	—	792
Net (loss) income	(5)	—	6	—	191	2	23	217
Allocation of MPC's net investment at acquisition	—	—	669	—	(337)	—	(332)	—
Distributions to unitholders and general partner	(513)	—	(142)	—	(190)	—	—	(845)
Distributions to noncontrolling interest	—	—	—	—	—	(3)	—	(3)
Contributions from noncontrolling interest	—	—	—	—	—	6	—	6
Class B unit conversion	133	(133)	—	—	—	—	—	—
Equity-based compensation	6	—	—	—	—	—	—	6
Deferred income tax impact from changes in equity	(2)	—	(13)	—	(2)	—	—	(17)
Balance at December 31, 2016	$8,086	$ 133	$1,069	$ —	$1,013	$ 18	$ —	$10,319

The accompanying notes are an integral part of these consolidated financial statements.

Notes to Consolidated Financial Statements

1. Description of the Business and Basis of Presentation

Description of the Business—MPLX LP is a diversified, growth-oriented master limited partnership formed by Marathon Petroleum Corporation. MPLX LP and its subsidiaries (collectively, the "Partnership") are engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs; and the gathering, transportation and storage of crude oil and refined petroleum products. The Partnership's principal executive office is located in Findlay, Ohio.

The Partnership was formed on March 27, 2012 as a Delaware limited partnership and completed its initial public offering (the "Initial Offering") on October 31, 2012. On December 4, 2015, a wholly-owned subsidiary of the Partnership merged with MarkWest Energy Partners L.P. (the "MarkWest Merger"), which is one of the largest processors of natural gas in the United States and the largest processor and fractionator in the Marcellus and Utica shale plays. This acquisition is discussed further in Note 4. Effective March 31, 2016, the Partnership acquired MPC's inland marine business, Hardin Street Marine LLC. The acquisition is also described further in Note 4. Unless the context otherwise requires, references in this report to "MPLX LP," the "Partnership," or like terms refer to MPLX LP and its subsidiaries, including MPLX Operations LLC ("MPLX Operations"), MPLX Terminal and Storage LLC ("MPLX Terminal and Storage"), MarkWest Energy Partners, L.P. ("MarkWest"), MarkWest Hydrocarbon, L.L.C. ("MarkWest Hydrocarbon"), MPLX Pipe Line Holdings LLC ("Pipe Line Holdings"), Marathon Pipe LLC ("MPL"), Ohio River Pipe Line LLC ("ORPL") and Hardin Street Marine LLC ("HSM"). References to "MPC" refer collectively to Marathon Petroleum Corporation and its subsidiaries, other than the Partnership. References to "Predecessor" refer collectively to HSM's related assets, liabilities and results of the operations.

The Partnership's business consists of two segments: Logistics and Storage ("L&S") and Gathering and Processing ("G&P"). See Note 10 for additional information regarding operations.

Basis of Presentation—The Partnership's consolidated financial statements include all majority-owned and controlled subsidiaries. For non-wholly-owned consolidated subsidiaries, the interests owned by third parties, including MPC, have been recorded as *Noncontrolling interest* in the accompanying Consolidated Balance Sheets. Intercompany investments, accounts and transactions have been eliminated. The Partnership's investments in which the Partnership exercises significant influence but does not control and does not have a controlling financial interest are accounted for using the equity method. The Partnership's investments in a VIE in which the Partnership exercises significant influence but does not control and is not the primary beneficiary are also accounted for using the equity method. The accompanying consolidated financial statements of the Partnership have been prepared in accordance with GAAP.

2. Summary of Principal Accounting Policies

Use of Estimates—The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ materially from those estimates. Estimates are subject to uncertainties due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change and affect items such as valuing identified intangible assets; determining the fair value of derivative instruments; valuing inventory; evaluating impairments of long-lived assets, goodwill and equity investments; establishing estimated useful lives for long-lived assets; acquisition accounting; recognizing share-based compensation expense; estimating revenues, expense accruals and capital expenditures; valuing AROs; and determining liabilities, if any, for environmental and legal contingencies.

Revenue Recognition—The Partnership's assessment of each of the revenue recognition criteria as they relate to its revenue producing activities are as follows: persuasive evidence of an arrangement exists, delivery, the fee is fixed or determinable and collectability is reasonably assured. It is upon delivery or title transfer to the customer that the Partnership meets all four revenue recognition criteria and it is at such time that the Partnership recognizes *Product sales*. Additionally, it is upon completion of services provided that the Partnership meets all four revenue recognition criteria and it is at such time that the Partnership recognizes *Service revenue*.

L&S Segment

Revenues are recognized in the L&S segment for crude oil and product pipeline transportation based on the delivery of actual volumes transported at regulated tariff rates. When MPC ships volumes on our pipeline systems under a joint tariff with a third party, those revenues are recorded as sales and other operating revenues, and not as sales to related parties, because we receive payment from the third party. Revenues are recognized for crude oil and refined product storage as performed based on contractual rates. Operating fees received for operating pipeline systems are recognized as a component of other income in the period the service is performed. All such amounts are reported as *Service revenue* on the Consolidated Statements of Income.

Under our MPC transportation services agreements, if MPC fails to transport its minimum throughput volumes during any quarter, then MPC will pay us a deficiency payment equal to the volume of the deficiency multiplied by the tariff rate then in effect. MPC may then apply the amount of any such deficiency payments as a credit for volumes transported on the applicable pipeline system in excess of its minimum volume commitment during the following four or eight quarters under the terms of the applicable transportation services agreement. The deficiency payments are initially recorded as *Deferred revenue—related parties* in the Consolidated Balance Sheets. The Partnership recognizes revenues for the deficiency payments at the earlier of when credits are used for volumes transported in excess of minimum volume commitments, when it becomes impossible to physically transport volumes necessary to utilize the credits or upon the expiration of the applicable four or eight quarter period. The use or expiration of the credits is a decrease in *Deferred revenue—related parties*. In addition, capital projects the Partnership undertakes at the request of MPC are reimbursed in cash and recognized in income over the remaining term of the applicable transportation services agreements.

HSM is a provider of marine transportation services for its customers and does not assume ownership of the products it transports. The Partnership transports cargo from a designated origin to a designated destination at a pre-established fixed rate. Costs incurred as part of moving the products are paid by the customer subsequent to April 1, 2016.

G&P Segment

The Partnership generates the majority of its G&P segment revenues from natural gas gathering, transportation and processing; NGL gathering, transportation, fractionation, marketing and storage; and crude oil gathering and transportation. The Partnership disaggregates revenue as *Product sales*, *Service revenue* and *Rental income* on the Consolidated Statements of Income. Revenue is reported as follows:

- *Product sales*—Product sales represent the sale of NGLs, condensate and natural gas. The product is primarily obtained as consideration for or related to providing midstream services.
- *Service revenue*—Service revenue represents all other revenue generated as the result of performing the services listed above.
- *Rental income*—Rental income represents revenue generated as the result of implicit operating lease arrangements.

The Partnership enters into a variety of contract types in order to generate *Product sales* and *Service revenue.* The Partnership provides services under the following different types of arrangements:

- *Fee-based arrangements*—Under fee-based arrangements, the Partnership receives a fee or fees for one or more of the following services: gathering, processing and transportation of natural gas; gathering, transportation, fractionation, exchange and storage of NGLs; and gathering and transportation of crude oil. The revenue the Partnership earns from these arrangements is generally directly related to the volume of natural gas, NGLs or crude oil that flows through the Partnership's systems and facilities and is not normally directly dependent on commodity prices. In certain cases, the Partnership's arrangements provide for minimum annual payments or fixed demand charges.

  - Fee-based arrangements are reported as *Service revenue* on the Consolidated Statements of Income. In certain instances when specifically stated in the contract terms, the Partnership purchases product after fee-based services have been provided. Revenue from the sale of products purchased after services are provided is reported as *Product sales* on the Consolidated Statements of Income and recognized on a gross basis as the Partnership is the principal in the transaction.

- *Percent-of-proceeds arrangements*—Under percent-of-proceeds arrangements, the Partnership gathers and processes natural gas on behalf of producers, sells the resulting residue gas, condensate and NGLs at market prices and remits to producers an agreed-upon percentage of the proceeds. In other cases, instead of remitting cash payments to the producer, the Partnership delivers an agreed-upon percentage of the residue gas and NGLs to the producer (take-in-kind arrangements) and sells the volumes the Partnership retains to third parties. Revenue from these arrangements is reported on a gross basis where the Partnership acts as the principal, as the Partnership has physical inventory risk and does not earn a fixed dollar amount. The agreed-upon percentage paid to the producer is reported as *Purchased product costs* on the Consolidated Statements of Income. Revenue is recognized on a net basis when the Partnership acts as an agent and earns a fixed dollar amount of physical product and does not have risk of loss of the gross amount of gas and/or NGLs. Percent-of-proceeds revenue is reported as *Product sales* on the Consolidated Statements of Income.

- *Keep-whole arrangements*—Under keep-whole arrangements, the Partnership gathers natural gas from the producer, processes the natural gas and sells the resulting condensate and NGLs to third parties at market prices. Because the extraction of the condensate and NGLs from the natural gas during processing reduces the Btu content of the natural gas, the Partnership must either purchase natural gas at market prices for return to producers or make cash payment to the producers equal to the energy content of this natural gas. Certain keep-whole arrangements also have provisions that require the Partnership to share a percentage of the keep-whole profits with the producers based on the oil to gas ratio or the NGL to gas ratio. Sales of NGLs under these arrangements are reported as *Product sales* on the Consolidated Statements of Income and are reported on a gross basis as the Partnership is the principal in the arrangement. Natural gas purchased to return to the producer and shared NGL profits are recorded as *Purchased product costs* in the Consolidated Statements of Income.

- *Percent-of-index arrangements*—Under percent-of-index arrangements, the Partnership purchases natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount. The Partnership then gathers and delivers the natural gas to pipelines where the Partnership resells the natural gas at the index price or at a different percentage discount to the index price. Revenue generated from percent-of-index arrangements are reported as *Product sales* on the Consolidated Statements of Income and are recognized on a gross basis as the Partnership purchases and takes title to the product prior to sale and is the principal in the transaction.

In many cases, the Partnership provides services under contracts that contain a combination of more than one of the arrangements described above. When fees are charged (in addition to product received) under keep-whole arrangements, percent-of-proceeds arrangements or percent-of-index arrangements, the Partnership records such fees as *Service revenue* on the Consolidated Statements of Income. The terms of the Partnership's contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements.

Amounts billed to customers for shipping and handling, including fuel costs, are included in *Product sales* on the Consolidated Statements of Income, except under contracts where we are acting as an agent. Shipping and handling costs associated with product sales are included in *Purchased product costs* on the Consolidated Statements of Income. Taxes collected from customers and remitted to the appropriate taxing authority are excluded from revenue. Facility expenses and depreciation represent those expenses related to operating our various facilities and are necessary to provide both *Product sales* and *Service revenue*.

Based on the terms of certain natural gas gathering, transportation and processing agreements, the Partnership is considered to be the lessor under several implicit operating lease arrangements in accordance with GAAP. The Partnership's primary implicit lease operations relate to a natural gas gathering agreement in the Marcellus Shale for which it earns a fixed-fee for providing gathering services to a single producer customer using a dedicated gathering system. As the gathering system is expanded, the fixed-fee charged to the producer is adjusted to include the additional gathering assets in the lease. Other significant implicit leases relate to a natural gas processing agreement in the Marcellus Shale and a natural gas processing agreement in the Southern Appalachia region for which the Partnership earns minimum monthly fees for providing processing services to a single producer using a dedicated processing plant. Revenues and costs related to the portion of the revenue earned under these contracts considered to be implicit leases are recorded as *Rental income* and *Rental cost of sales*, respectively, on the Consolidated Statements of Income. Similarly, the Partnership is considered to be the lessor under implicit operating lease arrangements with MPC in accordance with GAAP. The Partnership's primary implicit lease operations with MPC relate to the transportation services agreement between HSM and MPC. Revenue related to this agreement is recorded as *Rental income-related parties* on the Consolidated Statements of Income. The rental cost of sales related to the HSM implicit lease is depreciation of the HSM assets. All other services are provided to MPC on an as-needed basis and recorded as *Service revenue-related parties* on the Consolidated Statements of Income.

Revenue and Expense Accruals—The Partnership routinely makes accruals based on estimates for both revenues and expenses due to the timing of compiling billing information, receiving certain third-party information and reconciling the Partnership's records with those of third parties. The delayed information from third parties includes, among other things, actual volumes purchased, transported or sold, adjustments to inventory and invoices for purchases, actual natural gas and NGL deliveries and other operating expenses. The Partnership makes accruals to reflect estimates for these items based on its internal records and information from third parties. Estimated accruals are adjusted when actual information is received from third parties and the Partnership's internal records have been reconciled.

Cash and Cash Equivalents—Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with initial maturities of three months or less.

Restricted Cash—Restricted cash consists of cash and investments that must be maintained as collateral for letters of credit issued to certain third-party producer customers. The balances will be outstanding until certain capital projects are completed and the third party releases the restriction. Restricted cash also consists of cash advances to be used for the operation and maintenance of an operated pipeline system. At December 31, 2016 and 2015, the amount of restricted cash included in *Other current assets* on the Consolidated Balance Sheets was $5 million and $9 million, respectively.

Receivables—Receivables primarily consist of customer accounts receivable, which are recorded at the invoiced amount and generally do not bear interest. Management reviews the allowance quarterly. Past-due balances over 90 days and other higher risk amounts are reviewed individually for collectability. Balances that remain outstanding after reasonable collection efforts have been unsuccessful are written off through a charge to the valuation allowance and a credit to accounts receivable.

Inventories—Inventories consist primarily of natural gas, propane, other NGLs and materials and supplies to be used in operations. Natural gas, propane, and other NGLs are valued at the lower of weighted-average cost or net realizable value. Materials and supplies are stated at the lower of cost or net realizable value. Cost for materials and supplies is determined primarily using the weighted-average cost method. Processed natural gas and NGL inventories include material, labor and overhead. Shipping and handling costs related to purchases of natural gas and NGLs are included in inventory.

Imbalances—Within our pipelines and storage assets we experience volume gains and losses due to pressure and temperature changes, evaporation and variances in meter readings and other measurement methods. Until settled, positive imbalances are recorded as other current assets and negative imbalances are recorded as accounts payable. Positive and negative product imbalances are settled in cash, settled by physical delivery of gas from a different source, or tracked and settled in the future.

Property, Plant and Equipment—Property, plant and equipment are recorded at cost. Expenditures that extend the useful lives of assets are capitalized. Repairs, maintenance and renewals that do not extend the useful lives of the assets are expensed as incurred. Interest costs for the construction or development of long-lived assets are capitalized and amortized over the related asset's estimated useful life. Leasehold improvements are amortized over the shorter of the useful life or lease term.

When items of property, plant and equipment are sold or otherwise disposed of, any gains or losses are reported in the Consolidated Statements of Income. Gains on the disposal of property, plant and equipment are recognized when they occur, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale. The Partnership evaluates transactions involving the sale of property, plant and equipment to determine if they are, in-substance, the sale of real estate. Tangible assets may be considered real estate if the costs to relocate them for use in a different location exceed 10 percent of the asset's fair value. Financial assets, primarily in the form of ownership interests in an entity, may be in-substance real estate based on the significance of the real estate in the entity. Sales of real estate are not considered consummated if the Partnership maintains an interest in the asset after it is sold or has certain other forms of continuing involvement. Significant judgment is required to determine if a transaction is a sale of real estate and if a transaction has been consummated. If a sale of real estate is not considered consummated, the Partnership cannot record the transaction as a sale and must account for the transaction under an alternative method of accounting such as a financing or leasing arrangement.

The Partnership's policy is to evaluate whether there has been an impairment in the value of long-lived assets when certain events indicate that the remaining balance may not be recoverable. Qualitative and quantitative information is reviewed in order to determine if a triggering event has occurred or if an impairment indicator exists. If we determine that a triggering event has occurred we would complete a full impairment analysis. If we determine that the carrying value of a reporting unit is not recoverable, a loss is recorded for the difference between the fair value and the carrying value. The Partnership evaluates the carrying value of its property, plant and equipment on at least a segment level and at lower levels where the cash flows for specific assets can be identified, which generally is the component level for our G&P and L&S segments. Management considers the dedicated volume of producer customers' reserves and future NGL product and natural gas prices to estimate cash flows. The amount of additional producer customers' reserves developed by future drilling activity depends, in part, on expected commodity prices. Projections of producer customers' reserves, drilling activity and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast. Any significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset group.

For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value, less the cost to sell, to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is redetermined when related events or circumstances change.

Intangibles—The Partnership's intangibles are mainly comprised of customer contracts and related relationships acquired in business combinations and recorded under the acquisition method of accounting at their estimated fair values at the date of acquisition. Using relevant information and assumptions, management determines the fair value of acquired identifiable intangible assets. Fair value was calculated using the multi-period excess earnings method under the income approach for each reporting unit. This valuation method is based on first forecasting gross profit for the existing customer base and then applying expected attrition rates. The operating cash flows are calculated by determining the costs required to generate gross profit from the existing customer base. The key assumptions include overall gross profit growth, attrition rate of existing customers over time and the discount rate. Amortization of intangibles with definite lives is calculated using the straight-line method which is reflective of benefit pattern in which the estimated economic benefit is expected to be received over the estimated useful life of the intangible asset. The estimated economic life is determined by assessing the life of the assets related to the contracts and relationships, likelihood of renewals, the projected reserves, competitive factors, regulatory or legal provisions and maintenance and renewal costs.

Intangibles with indefinite lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the intangible may not be recoverable. If the sum of the expected undiscounted future cash flows related to the asset is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. The Partnership has no intangibles with indefinite lives.

Goodwill—Goodwill is the cost of an acquisition less the fair value of the net identifiable assets and noncontrolling interest, if any, of the acquired business. The Partnership evaluates goodwill for impairment annually as of November 30, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The Partnership determined its reporting units based on the criteria included in ASC 280 which requires a component to be a business with discrete financial information that management reviews on a regular basis. Management reviews its determination of reporting units on an annual basis. The Partnership may first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Partnership may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. During 2016, impairment charges of approximately $130 million were recorded. There were no impairments as a result of the Partnership's November 30, 2015 and November 30, 2016 goodwill impairment analyses.

Other Taxes—Other taxes primarily include real estate taxes.

Environmental Costs—Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. The Partnership recognizes remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure. A receivable is recorded for environmental costs indemnified by MPC.

Asset Retirement Obligations—An ARO is a legal obligation associated with the retirement of tangible long-lived assets that generally result from the acquisition, construction, development or normal operation of the asset. AROs are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a credit adjusted risk free interest rate and increases due to the passage of time based on the time value of money until the obligation is settled. The Partnership recognizes a liability of a conditional ARO as soon as the fair value of the liability can be reasonably estimated. A conditional ARO is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. AROs have not been recognized for certain assets because the fair value cannot be reasonably estimated since the settlement dates of the obligations are indeterminate. Such obligations will be recognized in the period when sufficient information becomes available to estimate a range of potential settlement dates.

Investment in Unconsolidated Affiliates—Equity investments in which the Partnership exercises significant influence, but does not control and is not the primary beneficiary, are accounted for using the equity method and are reported in *Equity method investments* in the accompanying Consolidated Balance Sheets. This includes entities in which we hold majority ownership but the minority shareholders have substantive participating rights. Differences in the basis of the investments and the separate net asset values of the investees, if any, are amortized into net income over the remaining useful lives of the underlying assets and liabilities, except for the excess related to goodwill.

The Partnership believes the equity method is an appropriate means for it to recognize increases or decreases measured by GAAP in the economic resources underlying the investments. Regular evaluation of these investments is appropriate to evaluate any potential need for impairment. The Partnership uses evidence of a loss in value to identify if an investment has an other than a temporary decline.

Deferred Financing Costs—Deferred financing costs are an asset for credit facility costs and netted against debt for senior notes. These costs are amortized over the contractual term of the related obligations using the effective interest method or, in certain circumstances, accelerated if the obligation is refinanced.

Derivative Instruments—Derivative instruments (including derivative instruments embedded in other contracts) are recorded at fair value and are reflected in the Consolidated Balance Sheets on a net basis, as either an asset or liability, as they are governed by the master netting agreements. The Partnership discloses the fair value of all of its derivative instruments under the captions *Other noncurrent assets*, *Other current liabilities* and *Deferred credits and other liabilities* on the Consolidated Balance Sheets, inclusive of option premiums, if any. Changes in the fair value of derivative instruments are reported in the Consolidated Statements of Income in accounts related to the item whose value or cash flows are being managed. All derivative instruments were marked to market through *Product sales*, *Purchased product costs*, or *Cost of revenues* on the Consolidated Statements of Income. Revenue gains and losses relate to contracts utilized to manage the cash flow for the sale of a product. Purchased product costs gains and losses relate to contracts utilized to manage the cost of natural gas purchases, typically related to keep-whole arrangements. Cost of revenues gains and losses relate to a contract utilized to manage electricity costs. Changes in risk management for unrealized activities are reported as an adjustment to net income in computing cash flow from operating activities on the accompanying Consolidated Statements of Cash Flows.

During the years ended December 31, 2016, 2015 and 2014, the Partnership did not designate any hedges or designate any contracts as normal purchases and normal sales, with the exception of electricity contracts, for which the normal purchases and normal sales designation was elected during the year ended December 31, 2016.

Fair Value of Financial Instruments—Management believes the carrying amount of financial instruments, including cash and cash equivalents, receivables, receivables from related parties, other current assets, accounts payable, accounts payable to related parties and accrued liabilities approximate fair value because of the short-term maturity of these instruments. The recorded value of the amounts outstanding under the bank revolving credit facility, if any, approximate fair value due to the variable interest rate that approximates current market rates (see Note 15). Derivative instruments are recorded at fair value, based on available market information (see Note 16).

Fair Value Measurement—Financial assets and liabilities recorded at fair value in the Consolidated Balance Sheets are categorized based upon a fair value hierarchy established by GAAP, which classifies the inputs used to measure fair value into the following levels:

- Level 1 inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 inputs to the valuation methodology 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 to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement.

The determination to classify a financial instrument within Level 3 of the valuation hierarchy is based upon the significance of the unobservable inputs to the overall fair value measurement. However, Level 3 financial instruments typically include, in addition to the unobservable or Level 3 inputs, observable inputs (that is, inputs that are actively quoted and can be validated to external sources); accordingly, the gains and losses for Level 3 financial instruments include changes in fair value due in part to observable inputs that are part of the valuation methodology. Level 3 financial instruments include crude oil options, all NGL derivatives and the embedded derivatives in commodity contracts discussed in Note 15 as they have significant unobservable inputs.

The methods and assumptions described above may produce a fair value that may not be realized in future periods upon settlement. Furthermore, while the Partnership believes its valuation methods are appropriate and consistent with other market participants, 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. For further discussion see Note 15.

Equity-Based Compensation Arrangements—The Partnership issues phantom units under its share-based compensation plan as described further in Note 20. A phantom unit entitles the grantee a right to receive a common unit upon the issuance of the phantom unit. The fair value of phantom unit awards granted to employees and non-employee directors is based on the fair market value of MPLX LP common units on the date of grant. The fair value of the units awarded is amortized into earnings using a straight-line amortization schedule over the period of service corresponding with the vesting period. For phantom units that vest immediately and are not forfeitable, equity-based compensation expense is recognized at the time of grant.

Performance units paying out in cash are accounted for as liability awards and recorded at fair value with a mark-to-market adjustment made each quarter. The performance units paying out in units are accounted for as equity awards and use a Monte Carlo valuation model to calculate a grant date fair value.

To satisfy common unit awards, the Partnership may issue new common units, acquire common units in the open market or use common units already owned by the general partner.

Tax Effects of Share-Based Compensation—The Partnership elected to adopt the simplified method to establish the beginning balance of the additional paid-in capital pool ("APIC Pool") related to the tax effects of employee share-based compensation and to determine the subsequent impact on the APIC Pool and Consolidated Statements of Cash Flows of the tax effects of share-based compensation awards that were outstanding upon adoption. Additional paid-in capital is reported as *Common unitholders—public* in the accompanying Consolidated Balance Sheets.

Income Taxes—The Partnership is not a taxable entity for federal income tax purposes. As a result of the MarkWest Merger, discussed further in Note 4, MarkWest was the surviving entity for tax purposes. MarkWest is not a taxable entity for federal income tax purposes. As such, the Partnership does not directly pay federal income tax. Taxes on the Partnership's net income generally are borne by its partners through the allocation of taxable income. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated Statements of Income, is includable in the federal income tax returns of each partner. The Partnership and certain legal entities are, however, taxable entities under certain state jurisdictions.

As a result of the Class A Reorganization discussed in Note 8, MarkWest Hydrocarbon (MarkWest Hydrocarbon, Inc. prior to the Class A Reorganization) is no longer a tax paying entity for federal income tax purposes or for the majority of states that impose an income tax effective September 1, 2016. Prior to the Class A Reorganization, in addition to paying tax on its own earnings, MarkWest Hydrocarbon recognized a tax expense or a tax benefit on its proportionate share of Partnership income or loss resulting from MarkWest Hydrocarbon's ownership of Class A units of the Partnership, even though for financial reporting purposes such income or loss was eliminated in consolidation. The Class A units represented limited partner interests with the same rights as common units except that the Class A units did not have voting rights, except as required by law. Class A units were not treated as outstanding common units in the Consolidated Balance Sheets as they were eliminated in the consolidation of MarkWest Hydrocarbon. The deferred income tax component prior to the reorganization related to the change in the temporary book to tax basis difference in the carrying amount of the investment in the Partnership which resulted primarily from timing differences in MarkWest Hydrocarbon's proportionate share of the book income or loss as compared with the MarkWest Hydrocarbon's proportionate share of the taxable income or loss of the Partnership.

The Partnership accounts for income taxes under the asset and liability method. Deferred income taxes are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis, capital loss carryforwards and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates applied to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized as tax expense (benefit) from continuing operations in the period that includes the enactment date of the tax rate change. Realizability of deferred tax assets is assessed and, if not more likely than not, a valuation allowance is recorded to reflect the deferred tax assets at net realizable value as determined by management. All deferred tax balances are classified as long-term in the accompanying Consolidated Balance Sheets. All changes in the tax bases of assets and liabilities are allocated among operations and items charged or credited directly to equity.

Distributions—In preparing the Consolidated Statements of Equity, net income attributable to MPLX LP is allocated to Preferred unitholders based on a fixed distribution schedule, as discussed in Note 9, and subsequently allocated to the general partner and limited partner unitholders. Distributions, although earned, are not accrued as a liability until declared. However, when distributions related to the incentive distribution rights are made, earnings equal to the amount of those distributions are first allocated to the general partner before the remaining earnings are allocated to the limited partner unitholders based on their respective ownership percentages. The allocation of net income attributable to MPLX LP for purposes of calculating net income per limited partner unit is described in below.

Net Income Per Limited Partner Unit—The Partnership uses the two-class method when calculating the net income per unit applicable to limited partners, because there is more than one class of participating security. The classes of participating securities include common units, subordinated units, general partner units, Preferred units, certain equity-based compensation awards and incentive distribution rights. Class B units are considered to be a separate class of common units that do not participate in distributions.

Net income attributable to MPLX LP is allocated to the unitholders differently for preparation of the Consolidated Statements of Equity and the calculation of net income per limited partner unit. In preparing the Consolidated Statements of Equity, net income attributable to MPLX LP is allocated to Preferred unitholders based on a fixed distribution schedule and subsequently allocated to remaining unitholders in accordance with their respective ownership percentages. However, when distributions related to the incentive distribution rights are made, earnings equal to the amount of those distributions are first allocated to the general partner before the remaining earnings are allocated to the unitholders, except Class B unitholders, based on their respective ownership percentages.

In preparing net income per limited partner units, during periods in which a net loss attributable to the Partnership is reported or periods in which the total distributions exceed the reported net income attributable to the Partnership's unitholders, the amount allocable to certain equity-based compensation awards is based on actual distributions to the equity-based compensation awards. Diluted earnings per unit is calculated by dividing net income attributable to the Partnership's common unitholders, after deducting amounts allocable to other participating securities, by the weighted average number of common units and potential common units outstanding during the period. Potential common units are excluded from the calculation of diluted earnings per unit during periods in which net income attributable to the Partnership's unitholders, after deducting amounts that are allocable to the outstanding equity-based compensation awards, Preferred units, and incentive distribution rights, is a loss as the impact would be anti-dilutive.

Business Combinations—The Partnership recognizes and measures the assets acquired and liabilities assumed in a business combination based on their estimated fair values at the acquisition date, with any remaining difference recorded as goodwill or gain from a bargain purchase. For all material acquisitions, management engages an independent valuation specialist to assist with the determination of fair value of the assets acquired, liabilities assumed, noncontrolling interest, if any, and goodwill, based on recognized business valuation methodologies. If the initial accounting for the business combination is incomplete by the end of the reporting period in which the acquisition occurs, an estimate will be recorded. Subsequent to the acquisition, and not later than one year from the acquisition date, the Partnership will record any material adjustments to the initial estimate based on new information obtained about facts and circumstances that existed as of the acquisition date. An income, market or cost valuation method may be utilized to estimate the fair value of the assets acquired, liabilities assumed, and noncontrolling interest, if any, in a business combination. The income valuation method represents the present value of future cash flows over the life of the asset using: (i) discrete financial forecasts, which rely on management's estimates of volumes, NGL prices, revenue and operating expenses; (ii) long-term growth rates; and (iii) appropriate discount rates. The market valuation method uses prices paid for a reasonably similar asset by other purchasers in the market, with adjustments relating to any differences between the assets. The cost valuation method is based on the replacement cost of a comparable asset at prices at the time of the acquisition reduced for depreciation of the asset. Acquisition-related costs are expensed as incurred in connection with each business combination. See Note 4 for more information about the MarkWest Merger.

Accounting for Changes in Ownership Interests in Subsidiaries—The Partnership's ownership interest in a consolidated subsidiary may change if it sells a portion of its interest or acquires additional interest or if the subsidiary issues or repurchases its own shares. If the transaction does not result in a change in control over the subsidiary, the transaction is accounted for as an equity transaction. If a sale results in a loss of control, it would result in the deconsolidation of a subsidiary with a gain or loss recognized in the Consolidated Statements of Income unless the subsidiary meets the definition of in-substance real estate. Deconsolidation of in-substance real estate is recorded at cost with no gain or loss recognized. If the purchase of additional interest occurs which changes the acquirer's ownership interest from noncontrolling to controlling, the acquirer's preexisting interest in the acquiree is remeasured to its fair value, with a resulting gain or loss recorded in earnings upon consummation of the business combination. Once an entity has control of a subsidiary, its acquisitions of some or all of the noncontrolling interests in that subsidiary are accounted for as equity transactions and are not considered to be a business combination.

3. Accounting Standards

Recently Adopted

In September 2015, the FASB issued an accounting standard update that eliminates the requirement to restate prior period financial statements for measurement period adjustments related to business combinations. This accounting standard update requires that the cumulative impact of a measurement period adjustment be recognized in the reporting period in which the adjustment is identified. The change was effective for interim and annual periods beginning after December 15, 2015. The Partnership recognized measurement period adjustments during the first and second quarters of 2016 on a cumulative prospective basis as additional analysis was completed on the preliminary purchase price allocation for the acquisition of MarkWest. See Notes 4 and 18 for further discussion and detail related to these measurement period adjustments.

In April 2015, the FASB issued an accounting standard update requiring that the earnings of transferred net assets prior to the dropdown date of the net assets to a master limited partnership be allocated entirely to the general partner when calculating earnings per unit under the two class method. Under this guidance, previously reported earnings per unit of the limited partners will not change as a result of a dropdown transaction. The change was effective for fiscal years and interim periods within those fiscal years beginning after December 15, 2015. Retrospective application is required. The Partnership adopted this accounting standard update in the first quarter of 2016 and it did not have a material impact on the consolidated financial statements.

In April 2015, the FASB issued an accounting standard update clarifying whether a customer should account for a cloud computing arrangement as an acquisition of a software license or as a service arrangement by providing characteristics that a cloud computing arrangement must have in order to be accounted for as a software license acquisition. The change was effective for fiscal years and interim periods within those fiscal years beginning after December 15, 2015. Retrospective or prospective application is allowed. The Partnership adopted this accounting standard update prospectively in the first quarter of 2016 and it did not have a material impact on the consolidated financial statements.

In February 2015, the FASB issued an accounting standard update making targeted changes to the current consolidation guidance. The accounting standard update changes the considerations related to substantive rights, related parties, and decision making fees when applying the VIE consolidation model and eliminates certain guidance for limited partnerships and similar entities under the voting interest consolidation model. The change was effective for fiscal years and interim periods within those fiscal years beginning after December 15, 2015. The Partnership adopted this accounting standard update in the first quarter of 2016 and it did not have a material impact on the consolidated financial statements.

In August 2014, the FASB issued an accounting standard update requiring management to assess an entity's ability to continue as a going concern and to provide related footnote disclosures in certain circumstances. Management is required to assess if there is substantial doubt about an entity's ability to continue as a going concern within one year after the issuance of the financial statements. Disclosures are required if conditions give rise to substantial doubt and the type of disclosure is determined based on whether management's plans will be able to alleviate the substantial doubt. The change was effective for the first fiscal period ending after December 15, 2016, and for fiscal periods and interim periods thereafter. The adoption of this accounting standard update in the fourth quarter of 2016 did not have a material impact on the Partnership's disclosures.

Not Yet Adopted

In January 2017, the FASB issued an accounting standard update which simplifies the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test. Under the new guidance, the recognition of an impairment charge is calculated based on the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. The guidance should be applied on a prospective basis, and is effective for annual or any interim goodwill impairment tests in fiscal years beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. The Partnership is in the process of determining the impact of the accounting standard update on the consolidated financial statements.

In January 2017, the FASB issued an accounting standard update to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is intended to narrow the definition of a business by specifying the minimum inputs and processes and by narrowing the definition of outputs. The change is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The guidance will be applied prospectively and early adoption is permitted for certain transactions. The Partnership is in the process of determining the impact of the accounting standard update on the consolidated financial statements.

In November 2016, the FASB issued an accounting standard update requiring that the statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. The change is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. Retrospective application is required. The application of this accounting standard update will not have a material impact on the Consolidated Statements of Cash Flows.

In October 2016, the FASB issued an accounting standard update to amend the consolidation guidance issued in February 2015 to require that a decision maker consider, in the determination of the primary beneficiary, its indirect interest in a VIE held by a related party that is under common control on a proportionate basis only. The change is effective for the financial statements for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years, with early adoption permitted. The Partnership is required to apply the standard retrospectively to January 1, 2016. The Partnership has analyzed the accounting standard update and does not expect an impact on the consolidated financial statements.

In August 2016, the FASB issued an accounting standard update related to the classification of certain cash flows. The accounting standard update provides specific guidance on eight cash flow classification issues, including debt prepayment or debt extinguishment costs and distributions received from equity method investees. The change is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The Partnership does not expect application of this accounting standard update to have a material impact on the Consolidated Statements of Cash Flows.

In June 2016, the FASB issued an accounting standard update related to the accounting for credit losses on certain financial instruments. The guidance requires that for most financial assets, losses are based on an expected loss approach which includes estimates of losses over the life of exposure that considers historical, current and forecasted information. Expanded disclosures related to the methods used to estimate the losses as well as a specific disaggregation of balances for financial assets are also required. The change is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, with early adoption permitted for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The Partnership does not expect application of this accounting standard update to have a material impact on the consolidated financial statements.

In March 2016, the FASB issued an accounting standard update on the accounting for employee share-based payments. This accounting standard update requires the recognition of income tax effects of awards through the income statement when awards vest or are settled. It will also increase the amount an employer can withhold for tax purposes without triggering liability accounting. Lastly, it allows employers to make a policy election to account for forfeitures as they occur. The changes are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years, and early adoption is permitted. Under the new guidance, the Partnership intends to continue estimating forfeiture rates to calculate compensation cost. The application of this accounting standard update will not have a material impact on the Partnership’s consolidated financial statements.

In February 2016, the FASB issued an accounting standard update requiring lessees to record virtually all leases on their balance sheets. The accounting standard update also requires expanded disclosures to help financial statement users better understand the amount, timing and uncertainty of cash flows arising from leases. For lessors, this amended guidance modifies the classification criteria and the accounting for sales-type and direct financing leases. The change will be effective on a modified retrospective basis for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, with early adoption permitted. The Partnership is currently evaluating the impact of this standard on our financial statements and disclosures, internal controls, and accounting policies. This evaluation process includes reviewing all forms of leases, performing a completeness assessment over the lease population and analyzing the practical expedients in order to determine the best path to implementation. The Partnership does not plan to early adopt the standard.

In January 2016, the FASB issued an accounting standard update requiring unconsolidated equity investments, not accounted for under the equity method, to be measured at fair value with changes in fair value recognized in net income. The accounting standard update also requires the use of the exit price notion when measuring the fair value of financial instruments for disclosure purposes and the separate presentation of financial assets and liabilities by measurement category and form on the balance sheet and accompanying notes. The accounting standard update eliminates the requirement to disclose the methods and assumptions used in estimating the fair value of financial instruments measured at amortized cost. Lastly, the accounting standard update requires separate presentation in other comprehensive income of the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk when electing to measure the liability at fair value in accordance with the fair value option for financial instruments. The changes are effective for fiscal years and interim periods within those fiscal years beginning after December 15, 2017. Early adoption is permitted only for guidance regarding presentation of the liability's credit risk. The application of this accounting standard update will not have a material impact on the Partnership's consolidated financial statements.

In May 2014, the FASB issued an initial accounting standard update for revenue recognition for contracts with customers. The guidance in the accounting standard update states that revenue is recognized when a customer obtains control of a good or service. Recognition of the revenue will involve a multiple step approach including identifying the contract, identifying the separate performance obligations, determining the transaction price, allocating the price to the performance obligations and then recognizing the revenue as the obligations are satisfied. Additional disclosures will be required to provide adequate information to understand the nature, amount, timing and uncertainty of reported revenues and revenues expected to be recognized. The change will be effective on a retrospective or modified retrospective basis for fiscal years beginning after December 15, 2017, and interim periods within those years, with early adoption permitted no earlier than January 1, 2017.

The Partnership is currently evaluating the impact of the revenue recognition standard on the Partnership's financial statements and disclosures, internal controls, and accounting policies. This evaluation process includes a phased approach, the first phase of which includes reviewing a sample of our contracts and transaction types across our segments. The Partnership is currently in the process of completing this first phase and evaluating the methods of adoption.

Based on the results of the first phase assessment to date, the Partnership has reached tentative conclusions for some contract types and does not believe revenue recognition patterns for fee-based or percent-of-proceeds contracts will change materially. The Partnership is currently working to understand the accounting impact on keep-whole and percent-of-liquids agreements under the new standard, specifically related to the accounting for noncash consideration received in the form of a commodity product. The Partnership does expect certain amounts to be grossed up in revenue as a result of implementation. The Partnership continues to work through implementation efforts and will provide updates as qualitative and quantitative conclusions are reached throughout 2017.

4. Acquisitions

Acquisition of Hardin Street Marine LLC

On March 14, 2016, the Partnership entered into a Membership Interests Contribution Agreement (the "Contribution Agreement") with MPLX GP LLC ("MPLX GP"), MPLX Logistics Holdings LLC and MPC Investment LLC ("MPC Investment"), each a wholly-owned subsidiary of MPC, related to the acquisition of HSM, MPC's inland marine business, from MPC. Pursuant to the Contribution Agreement, the transaction was valued at $600 million, consisting of a fixed number of common units and general partner units of 22,534,002 and 459,878, respectively. The general partner units maintain MPC's two percent general partner interest in the Partnership. The acquisition closed on March 31, 2016 and the fair value of the common units and general partner units issued was $669 million and $14 million, respectively, as recorded on the Consolidated Statements of Equity. MPC agreed to waive distributions in the first quarter of 2016 on MPLX LP common units issued in connection with this transaction. MPC did not receive general partner distributions or incentive distribution rights that would have otherwise accrued on such MPLX LP common units with respect to the first quarter distributions. The value of these waived distributions was $15 million.

The inland marine business, comprised of 18 tow boats and 205 barges which transport light products, heavy oils, crude oil, renewable fuels, chemicals and feedstocks in the Midwest and U.S. Gulf Coast regions, accounted for nearly 60 percent of the total volumes MPC shipped by inland marine vessels as of March 31, 2016. The Partnership accounts for HSM as a reporting unit of the L&S segment.

The acquisition from MPC was a transfer between entities under common control. As an entity under common control with MPC, the Partnership recorded the assets acquired from MPC on its consolidated Balance Sheets at MPC's historical basis instead of fair value. Transfers of businesses between entities under common control require prior periods to be retrospectively adjusted to furnish comparative information. Accordingly, the Partnership has retrospectively adjusted the historical financial results for all periods to include HSM.

Purchase of MarkWest Energy Partners, L.P.

On December 4, 2015, a wholly-owned subsidiary of the Partnership merged with MarkWest. Each common unit of MarkWest issued and outstanding immediately prior to the effective time of the MarkWest Merger was converted into a right to receive 1.09 common units representing limited partner interests in MPLX LP, plus a one-time cash payment of $6.20 per unit. Each Class B unit of MarkWest issued and outstanding immediately prior to the effective time of the MarkWest Merger was converted into the right to receive one Class B unit of MPLX LP. Each Class B unit of MPLX LP will convert into 1.09 common units of MPLX LP and the right to receive $6.20 in cash, and the conversion of the Class B units will occur in equal installments, the first of which occurred on July 1, 2016 and the second of which will occur on July 1, 2017. MPC contributed approximately $1.3 billion of cash to the Partnership to pay the aggregate cash consideration to MarkWest unitholders, without receiving any new equity in exchange. At closing, MPC made a payment of $1.2 billion to MarkWest common unitholders and the remaining $50 million is payable in equal amounts, the first of which was paid in July 2016 and the second of which will be paid in July 2017, in connection with the conversion of the remaining outstanding Class B units to MPLX LP common units. The Partnership's financial results reflect the results MarkWest from the date of the acquisition.

The components of the fair value of consideration transferred are as follows:

(In millions)	
Fair value of units issued	$7,326
Cash	1,230
Paid/payable to MarkWest Class B unitholders	50
Total fair value of consideration transferred	$8,606

The following table summarizes the final purchase price allocation. Subsequent to December 31, 2015, additional analysis was completed and adjustments were made to the preliminary purchase price allocation as noted in the table below. The fair value of assets acquired and liabilities and noncontrolling interests assumed at the acquisition date as of December 31, 2016, are as follows:

(In millions)	As Originally Reported	Adjustments	As Adjusted
Cash and cash equivalents	$ 12	$ —	$ 12
Receivables	164	—	164
Inventories	33	(1)	32
Other current assets	44	—	44
Equity method investments	2,457	143	2,600
Property, plant and equipment	8,474	43	8,517
Intangibles	468	65	533
Other noncurrent assets	5	—	5
Total assets acquired	11,657	250	11,907
Accounts payable	322	—	322
Accrued liabilities	13	6	19
Accrued taxes	21	—	21
Other current liabilities	44	—	44
Long-term debt	4,567	—	4,567
Deferred income taxes	374	3	377
Deferred credits and other liabilities	151	—	151
Noncontrolling interest	13	—	13
Total liabilities and noncontrolling interest assumed	5,505	9	5,514
Net assets acquired excluding goodwill	6,152	241	6,393
Goodwill	2,454	(241)	2,213
Net assets acquired	$ 8,606	$ —	$ 8,606

Adjustments to the preliminary purchase price stem mainly from additional information obtained by management in the first and second quarters of 2016 about facts and circumstances that existed at the acquisition date, including updates to forecasted employee benefit costs, maintenance capital expenditures and completion of certain valuations to determine the underlying fair value of certain acquired assets. The adjustment to intangibles mainly relates to a misstatement in the original preliminary purchase price allocation. The correction of the error resulted in a $68 million reduction to the carrying value of goodwill and an offsetting increase of $64 million in intangibles and $2 million in each of equity method investments and property, plant and equipment. Management concluded that the correction of the error is immaterial to the consolidated financial statements of all periods presented. As further discussed in Note 18, in the first quarter of 2016 the Partnership recorded a goodwill impairment charge based on the implied fair value of goodwill as of the interim impairment analysis date. During the second quarter of 2016, the Partnership finalized its analysis of the final purchase price allocation. The completion of the purchase price allocation resulted in a refinement of the impairment expense recorded, as more fully discussed in Note 18.

The increase to the fair value of intangibles and property, plant and equipment noted above resulted in additional amortization and depreciation expense of approximately $1 million recognized for the year ended December 31, 2016, in *Depreciation and amortization* in the Consolidated Statements of Income, that would have been recorded for the year ended December 31, 2015, had the fair value adjustments been recorded as of December 4, 2015. The increase in the fair value of equity investments above would not have had a material effect on the income from equity method investments had the fair value adjustment been recorded as of December 4, 2015.

The purchase price allocation resulted in the recognition of $2.2 billion of goodwill in three reporting units within the Partnership's G&P segment, substantially all of which is not deductible for tax purposes. Goodwill represents the complimentary aspects of the highly diverse asset base of MarkWest and MPLX LP that will provide significant additional opportunities across multiple segments of the hydrocarbon value chain.

The Partnership recognized $36 million of acquisition-related costs associated with the MarkWest Merger. These costs were expensed, with $30 million included in *General and administrative expenses* and $6 million included in *Other financial costs*.

The fair value of the common units issued was determined on the basis of the closing market price of the Partnership's units as of the effective time of the transaction and is considered a Level 1 measurement. The fair value of the Class B units issued was determined based on reference to the value of the common units, adjusted for a lack of distributions prior to their stated conversion dates, and is considered a Level 2 measurement. The fair values of the long-term debt and SMR liabilities were determined as of the acquisition date using the methods discussed in Note 15.

The fair value of the equity method investments was determined based on applying the discounted cash flow method, which is an income approach, to the Partnership's equity method investments on an individual basis. Key assumptions include discount rates of 9.4 percent to 11.1 percent and terminal values based on the Gordon growth method to capitalize the cash flows, using a 2.5 percent long term growth rate. Intangibles represent customer contracts and related relationships. The fair value of the intangibles was determined based on applying the multi-period excess earnings method, which is an income approach. Key assumptions include attrition rates by reporting unit ranging from 5.0 percent to 10.0 percent and discount rates by reporting unit ranging from 11.5 percent to 12.8 percent. The fair value of property, plant and equipment was determined primarily based on the cost approach. Key assumptions include inputs to the valuation methodology such as recent purchases of similar items and published data for similar items. Components were adjusted for economic and functional obsolescence, location, normal useful lives, and capacity (if applicable). The fair value measurements for equity method investments, intangibles, and property, plant and equipment are based on significant inputs that are not observable in the market and, therefore, represent Level 3 measurements.

The amounts of revenue and income from operations associated with MarkWest in the Consolidated Statements of Income for 2015 are as follows:

(In millions)	2015
Revenues and other income	$126
Income from operations	32

Unaudited Pro Forma Financial Information

The following unaudited pro forma financial information presents consolidated results assuming the MarkWest Merger occurred on January 1, 2014.

(In millions, except per unit data)	2015	2014
Revenues and other income	$2,677	$2,972
Net income attributable to MPLX LP	247	330
Net income attributable to MPLX LP per unit—basic	0.47	1.09
Net income attributable to MPLX LP per unit—diluted	0.45	1.03

The unaudited pro forma financial information includes adjustments primarily to align accounting policies, adjust depreciation expense to reflect the fair value of property, plant and equipment, increase amortization expense related to identifiable intangible assets and adjust interest expense related to the fair value of MarkWest's long-term debt, as well as the related income tax effects. The pro forma financial information does not give effect to potential synergies that could result from the acquisition and is not necessarily indicative of the results of future operations.

MarkWest has a 60 percent legal ownership interest in MarkWest Utica EMG for the years ended December 31, 2015 and 2014, respectively. MarkWest Utica EMG's inability to fund its planned activities without subordinated financial support qualify it as a VIE. The financing structure for MarkWest Utica EMG at its inception resulted in a de-facto agent relationship under which MarkWest was deemed to be the primary beneficiary of MarkWest Utica EMG. Therefore, MarkWest consolidated MarkWest Utica EMG in its historical financial statements. In the fourth quarter of 2015, based on economic conditions and other pertinent factors, the accounting for its investment in MarkWest Utica EMG was re-assessed. As of December 4, 2015, the entity has been deconsolidated. For purposes of this pro forma financial information, MarkWest Utica EMG has been consolidated for the period prior to the acquisition consistent with its treatment in the historical periods presented.

A summary of the amounts included in the historical financial statements of MarkWest for the year ended December 31, 2014 and the period from January 1, 2015 through December 3, 2015 related to MarkWest Utica EMG are as follows:

(in millions)	2015	2014
Revenue and other income	$152	$ 85
Cost of revenue excluding depreciation and amortization	27	48
Depreciation and amortization	61	50
Net income attributable to noncontrolling interest	64	31
Net loss	(5)	(46)

EMG Utica, LLC ("EMG Utica"), a joint venture partner in MarkWest Utica EMG, received a special non-cash allocation of income of approximately $41 million and $37 million for the period from January 1, 2015 through December 3, 2015 and the year ended December 31, 2014, respectively. See Note 5 for a description of the transaction and its impact on the financial statements. Net income of MarkWest would not have changed had MarkWest Utica EMG been deconsolidated for the year ended December 31, 2014 and the period from January 1, 2015 through December 3, 2015.

Purchases of Pipe Line Holdings

Effective December 4, 2015, the Partnership purchased the remaining 0.5 percent interest in Pipe Line Holdings from subsidiaries of MPC for consideration of $12 million. This resulted in Pipe Line Holdings becoming a wholly-owned subsidiary of the Partnership. The Partnership recorded the 0.5 percent interest at its historical carrying value of $6 million and the excess cash paid and equity contributed over historical carrying value of $6 million as a decrease to general partner equity. Prior to this transaction, the 0.5 percent interest was held by MPC and was reflected as the noncontrolling interest retained by MPC in the consolidated financial statements.

Effective December 1, 2014, the Partnership purchased a 22.875 percent interest in Pipe Line Holdings from subsidiaries of MPC for consideration of $600 million, which was financed through borrowings under our bank revolving credit facility, as discussed in Note 17. In addition, the Partnership accepted a contribution of 7.625 percent of outstanding partnership interests of Pipe Line Holdings from subsidiaries of MPC in exchange for the issuance of equity valued at $200 million, as discussed in Note 8. The Partnership recorded the combined 30.5 percent interest at its historical carrying value of $335 million and the excess cash paid and equity contributed over historical carrying value of $465 million as a decrease to general partner equity. Prior to this transaction, the 30.5 percent interest was held by MPC and was reflected as part of the noncontrolling interest retained by MPC in the consolidated financial statements. Beginning December 1, 2014, the consolidated financial statements reflect the 99.5 percent general partner interest in Pipe Line Holdings owned by MPLX LP, while the 0.5 percent limited partner interest held by MPC is reflected as a noncontrolling interest.

On March 1, 2014, the Partnership acquired a 13 percent interest in Pipe Line Holdings from MPC for consideration of $310 million, which was funded with $40 million of cash on hand and $270 million of borrowings on the bank revolving credit facility. The Partnership recorded the 13 percent interest in Pipe Line Holdings at its historical carrying value of $138 million and the excess cash paid over historical carrying value of $172 million as a decrease to general partner equity.

In addition, on May 1, 2013, the Partnership acquired a five percent interest in Pipe Line Holdings from MPC for consideration of $100 million, which was funded with cash on hand. The Partnership recorded the five percent interest in Pipe Line Holdings at its historical carrying value of $54 million and the excess cash paid over historical carrying value of $46 million as a decrease to general partner equity.

These acquisitions were accounted for on a prospective basis and the terms of the acquisitions were approved by the conflicts committee of the board of directors of the general partner, which is comprised entirely of independent directors.

Changes in MPLX LP's equity resulting from changes in its ownership interest in Pipe Line Holdings were as follows:

(In millions)	2015	2014
Net income attributable to MPLX LP	$156	$ 121
Transfer to noncontrolling interest:		
Decrease in general partner-MPC equity for purchases of additional interest in Pipe Line Holdings	(6)	(638)
Change from net income attributable to MPLX LP and transfer to noncontrolling interest	$150	$(517)

5. Equity Method Investments

MarkWest Utica EMG

Effective January 1, 2012, MarkWest Utica Operating Company, LLC ("Utica Operating"), a wholly-owned and consolidated subsidiary of MarkWest, and EMG Utica (together the "Members") executed agreements to form a joint venture, MarkWest Utica EMG, to develop significant natural gas gathering, processing and NGL fractionation, transportation and marketing infrastructure in eastern Ohio. The related limited liability company agreement has been amended from time to time (the limited liability company agreement as currently in effect is referred to as the "Amended LLC Agreement"). The aggregate funding commitment of EMG Utica was $950 million (the "Minimum EMG Investment"). Thereafter, Utica Operating was required to fund, as needed, 100 percent of future capital for MarkWest Utica EMG until such time as the aggregate capital that had been contributed by the Members reached $2 billion, which occurred prior to the MarkWest Merger. Until such time as the investment balances of Utica Operating and EMG Utica are in the ratio of 70 percent and 30 percent, respectively (such time being referred to as the "Second Equalization Date"), EMG Utica will have the right, but not the obligation, to fund up to 10 percent of each capital call for MarkWest Utica EMG, and Utica Operating will be required to fund all remaining capital not elected to be funded by EMG Utica. After the Second Equalization Date, Utica Operating and EMG Utica will have the right, but not the obligation, to fund their pro rata portion (based on their respective investment balances) of any additional required capital and may also fund additional capital that the other party elects not to fund. As of December 31, 2016, EMG Utica has contributed $1 billion and Utica Operating has contributed approximately $1.5 billion to MarkWest Utica EMG.

Under the Amended LLC Agreement, after EMG Utica has contributed more than $500 million to MarkWest Utica EMG and prior to December 31, 2016, EMG Utica's investment balance will also be increased by a quarterly special non-cash allocation of income ("Preference Amount") that is based upon the amount of capital contributed by EMG Utica in excess of $500 million. No Preference Amount will accrue to EMG Utica's investment balance after December 31, 2016. EMG Utica received a special non-cash allocation of income of approximately $16 million and approximately $4 million for the year ended December 31, 2016 and for the 28 days ended December 31, 2015, respectively.

Under the Amended LLC Agreement, Utica Operating continued to receive 60 percent of cash generated by MarkWest Utica EMG that was available for distribution until the earlier of December 31, 2016 or the date on which Utica Operating's investment balance equaled 60 percent of the aggregate investment balances of the Members. After December 31, 2016, cash generated by MarkWest Utica EMG that is available for distribution will be allocated to the Members in proportion to their respective investment balances. As of December 31, 2016, Utica Operating's investment balance in MarkWest Utica EMG was approximately 56 percent.

MarkWest Utica EMG is deemed to be a VIE. As of the date of the MarkWest Merger, Utica Operating is not deemed to be the primary beneficiary due to EMG Utica's voting rights on significant matters. The Partnership's portion of MarkWest Utica EMG's net assets, which was $2.2 billion at December 31, 2016 and 2015, respectively, is reported under the caption *Equity Method Investments* on the Consolidated Balance Sheets. The Partnership's maximum exposure to loss as a result of its involvement with MarkWest Utica EMG includes its equity investment, any additional capital contribution commitments and any operating expenses incurred by the subsidiary operator in excess of its compensation received for the performance of the operating services. The Partnership did not provide any financial support to MarkWest Utica EMG that it was not contractually obligated to provide during the year ended December 31, 2016 and the 28 days ended December 31, 2015. The Partnership receives management fee revenue for engineering and construction and administrative services for operating MarkWest Utica EMG, and is also reimbursed for personnel services ("Operational Service" revenue). The amount of Operational Service revenue related to MarkWest Utica EMG for the year ended December 31, 2016 and for the 28 days ended December 31, 2015 was $16 million and less than $1 million, respectively, and is reported as *Other income—related parties* in the Consolidated Statements of Income.

Ohio Gathering

Ohio Gathering is a subsidiary of MarkWest Utica EMG and is engaged in providing natural gas gathering services in the Utica Shale in eastern Ohio. Ohio Gathering is a joint venture between MarkWest Utica EMG and Summit Midstream Partners, LLC ("Summit"). As of December 31, 2016, we have a 34 percent indirect ownership interest in Ohio Gathering. As Ohio Gathering is a subsidiary of MarkWest Utica EMG, which is accounted for as an equity method investment, the Partnership reports its portion of Ohio Gathering's net assets as a component of its investment in MarkWest Utica EMG. The Partnership receives Operational Service revenue for operating Ohio Gathering. The amount of Operational Service revenue related to Ohio Gathering for the year ended December 31, 2016 and the 28 days ended December 31, 2015 was approximately $15 million and $2 million, respectively, and is reported as *Other income—related parties* in the Consolidated Statements of Income.

Ohio Condensate

Ohio Condensate is a joint venture between MarkWest Utica EMG Condensate, L.L.C., a wholly-owned and consolidated subsidiary of MarkWest, and Summit formed for the purpose of gathering (by pipeline), stabilization, terminalling, transportation and storage of well-head condensate within certain defined areas in the state of Ohio. The Partnership accounts for Ohio Condensate, which is a VIE, as an equity method investment as MPLX LP exercises significant influence, but does not control Ohio Condensate and is not its primary beneficiary due to Summit's voting rights on significant matters. The Partnership's portion of Ohio Condensate's net assets, which was $10 million and $100 million at December 31, 2016 and 2015, respectively, are reported under the caption *Equity method investments* on the Consolidated Balance Sheets. The Partnership receives Operational Service revenue for operating Ohio Condensate. The amount of Operational Service revenue related to Ohio Condensate for the year ended December 31, 2016 and the 28 days ended December 31, 2015 was $4 million and less than $1 million, respectively, and is reported as *Other income—related parties* in the Consolidated Statements of Income.

Summarized financial information for the year ended December 31, 2016 and from the date of the MarkWest Merger through December 31, 2015 for equity method investments is as follows:

	Year Ended December 31, 2016				
(In millions)	MarkWest Utica EMG	Ohio Condensate	Other VIEs	Non-VIEs	Total
Revenue and other income	$216	$ 15	$ 3	$148	$382
Cost and expenses	100	110	1	117	328
Income (loss) from operations	116	(95)	2	31	54
Net income (loss)	114	(95)	2	31	52
Income (loss) from equity method investments[2]	8	(89)	—	7	(74)

	Year Ended December 31, 2015				
(In millions)	MarkWest Utica EMG	Ohio Condensate	Other VIEs	Non-VIEs	Total
Revenue and other income	$ 18	$ 2	$—	$ 9	$ 29
Cost and expenses	9	2	—	8	19
Income from operations	9	—	—	1	10
Net income	10	—	—	1	11
Income from equity method investments[2]	2	1	—	—	3

Summarized balance sheet information as of December 31, 2016 and 2015 for equity method investments is as follows:

	December 31, 2016				
(In millions)	MarkWest Utica EMG[1]	Ohio Condensate	Other VIEs	Non-VIEs	Total
Current assets	$ 45	$ 2	$—	$ 40	$ 87
Noncurrent assets	2,173	30	102	375	2,680
Current liabilities	30	3	1	26	60
Noncurrent liabilities	2	13	—	—	15

	December 31, 2015				
(In millions)	MarkWest Utica EMG[1]	Ohio Condensate	Other VIEs	Non-VIEs	Total
Current assets	$ 113	$ 7	$—	$ 30	$ 150
Noncurrent assets	2,207	127	42	243	2,619
Current liabilities	77	6	1	18	102
Noncurrent liabilities	1	12	—	—	13

(1) MarkWest Utica EMG's noncurrent assets includes its investment in its subsidiary Ohio Gathering, which does not appear elsewhere in this table. The investment was $794 million and $781 million as of December 31, 2016 and 2015, respectively.

(2) *Income (loss) from equity method investments* includes the impact of any basis differential amortization or accretion.

As of December 31, 2016 and 2015, the carrying value of our equity method investments was $1.1 billion and $961 million, respectively, higher than the underlying net assets of investees. This basis difference is being amortized or accreted into net income over the remaining estimated useful lives of the underlying net assets, except for $459 million of excess related to goodwill as of December 31, 2016.

During the second quarter of 2016, forecasts for Ohio Condensate were reduced to align with updated forecasts for customer requirements. As the operator of that entity responsible for maintaining its financial records, the Partnership completed a fixed asset impairment analysis as of June 30, 2016, in accordance with ASC Topic 360, to determine the potential fixed asset impairment charge. The resulting fixed asset impairment charge recorded within Ohio Condensate's financial statements was $96 million. Based on the Partnership's 60 percent ownership of Ohio Condensate, approximately $58 million was recorded in the second quarter of 2016 in *(Loss) income from equity method investments* on the accompanying Consolidated Statements of Income.

The Partnership's investment in Ohio Condensate, which was established at fair value in connection with the MarkWest Merger, exceeded its proportionate share of the underlying net assets. Therefore, in conjunction with the ASC Topic 360 impairment analysis, the Partnership completed an equity method impairment analysis in accordance with ASC Topic 323 to determine the potential additional equity method impairment charge to be recorded on the Partnership's consolidated financial statements resulting from an other-than-temporary impairment. As a result, an additional impairment charge of approximately $31 million was recorded in the second quarter of 2016 in *(Loss) income from equity method investments* on the accompanying Consolidated Statements of Income, which eliminated the basis differential established in connection with the MarkWest Merger.

The fair value of Ohio Condensate and its underlying fixed assets was determined based upon applying the discounted cash flow method, which is an income approach, and the guideline public company method, which is a market approach. The discounted cash flow fair value estimate is based on known or knowable information at the interim measurement date. The significant assumptions that were used to develop the estimate of the fair value under the discounted cash flow method include management's best estimates of the expected future results using a probability-weighted average set of cash flow forecasts and a discount rate of 11.2 percent. An increase to the discount rate of 50 basis points would have resulted in an additional charge of $1 million on the Consolidated Statements of Income. Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As such, the fair value of the Ohio Condensate equity method investment and its underlying fixed assets represents a Level 3 measurement. As a result, there can be no assurance that the estimates and assumptions made for purposes of the interim impairment test will prove to be an accurate prediction of the future.

6. Related Party Agreements and Transactions

The Partnership's material related parties include:

- MPC, which refines, markets and transports crude oil and petroleum products, primarily in the Midwest, Gulf Coast, East Coast and Southeast regions of the United States.
- Centennial Pipeline LLC ("Centennial"), in which MPC has a 50 percent interest. Centennial owns a products pipeline and storage facility.
- Muskegon Pipeline LLC ("Muskegon"), in which MPC has a 60 percent interest. Muskegon owns a common carrier products pipeline.
- MarkWest Utica EMG, in which MPLX LP has a 56 percent interest as of December 31, 2016. MarkWest Utica EMG is engaged in significant natural gas processing and NGL fractionation, transportation and marketing in the state of Ohio.
- Ohio Gathering, in which MPLX LP has a 34 percent indirect interest as of December 31, 2016. Ohio Gathering is a subsidiary of MarkWest Utica EMG providing natural gas gathering service in the Utica Shale region of eastern Ohio.
- Ohio Condensate, in which MPLX LP has a 60 percent interest. Ohio Condensate is engaged in wellhead condensate gathering, stabilization, terminalling, transportation and storage within certain defined areas of Ohio.

Commercial Agreements

The Partnership has various long-term, fee-based transportation services and storage services agreements with MPC. Under these long term, fee based agreements, the Partnership provides transportation and storage services to MPC, and MPC has committed to provide the Partnership with minimum quarterly throughput volumes on crude oil and products systems and minimum storage volumes of crude oil, products and butane. The Partnership believes the terms and conditions under these agreements, as well as the initial agreements with MPC described below, are generally no less favorable to either party than those that could have been negotiated with unaffiliated parties with respect to similar services.

The commercial agreements with MPC include:

- three separate 10-year transportation services agreements and one five-year transportation services agreement under which MPC pays the Partnership fees for transporting crude oil on various of our crude oil pipeline systems;
- four separate 10-year transportation services agreements under which MPC pays the Partnership fees for transporting products on each of our refined product pipeline systems;
- a five-year transportation services agreement under which MPC pays the Partnership fees for handling crude oil and products at our Wood River, Illinois barge dock;
- a 10-year storage services agreement under which MPC pays the Partnership fees for providing storage services at our Neal, West Virginia butane cavern;
- five separate three-year storage services agreements under which MPC pays the Partnership fees for providing storage services at our tank farms; and
- a six-year transportation services agreement under which MPC pays the Partnership fees for providing marine transportation of crude oil, feedstocks and refined petroleum products, and related services.

All of the transportation services agreements with MPC for the Partnership's crude oil and product pipeline systems include automatic renewal terms ranging from two to five years, unless terminated by either party. The Partnership's butane cavern storage services agreement with MPC does not automatically renew. The storage services agreements with MPC for the Partnership's tank farms automatically renew for additional one-year terms unless terminated by either party.

Under all of our transportation services agreements, except for our marine agreement, if MPC fails to transport its minimum throughput volumes during any quarter, then MPC will pay us a deficiency payment equal to the volume of the deficiency multiplied by the tariff rate then in effect (the "Quarterly Deficiency Payment"). Under these transportation services agreements, the amount of any Quarterly Deficiency Payment paid by MPC may be applied as a credit for any volumes transported on the applicable pipeline system in excess of MPC's minimum volume commitment during any of the succeeding four quarters, or eight quarters in the case of the transportation services agreements covering our Wood River to Patoka crude system and our Wood River barge dock, after which time any unused credits will expire. Upon the expiration or termination of a transportation services agreement, MPC will have the opportunity to apply any such remaining credit amounts until the completion of any such four-quarter or eight-quarter period, as applicable. Any such remaining credits may be used against any volumes shipped by MPC on the applicable pipeline system, without regard to any minimum volume commitment that may have been in place during the term of the agreement.

Under the storage services agreements, as amended, the Partnership is obligated to make available to MPC on a firm basis the available storage capacity at our tank farms and butane cavern, and MPC pays the Partnership a per-barrel fee for such storage capacity, regardless of whether MPC fully utilizes the available capacity.

On January 1, 2015, HSM entered into a long-term, fee-based transportation services agreement with MPC for a period of six years. Under the agreement, the Partnership provides marine transportation of crude oil, feedstocks and refined petroleum products, as well as related services. Under the agreement MPC pays HSM monthly for the following: the specified day rate for equipment and charges for services related to transportation, tankerman services and cleaning and repair charges. Fleeting services are billed monthly. On the anniversary of the contract, pursuant to the amended and restated fee-based transportation services agreement effective July 1, 2015, the day rates and charges for services related to transportation are adjusted for inflation. Prior to January 1, 2015, this agreement did not exist.

On January 1, 2015, MPC conveyed various operating leases to HSM for third-party barges and fleeting property within the states of Indiana, Kentucky, Louisiana, Ohio and West Virginia in which MPC was either the lessor or lessee.

Operating Agreements

The Partnership operates various pipeline systems owned by MPC under operating services agreements. Under these operating services agreements, the Partnership receives an operating fee for operating the assets and is reimbursed for all direct and indirect costs associated with operating the assets. Most of these agreements are indexed for inflation. These agreements range from one to five years in length and automatically renew unless terminated by either party.

Management Services Agreements

The Partnership has two management services agreements with MPC under which it provides management services to MPC with respect to certain of MPC's retained pipeline assets. The Partnership may adjust annually for inflation and based on changes in the scope of management services provided.

The Partnership also receives engineering and construction and administrative management fee revenue and other direct personnel costs for operating some joint venture entities.

The Partnership, through its subsidiary, HSM, has a management services agreement with MPC under which it provides management services to assist MPC in the oversight and management of the marine business. HSM receives a fixed annual fee for providing the required management services. This fee is adjusted annually on the anniversary of the contract for inflation and any changes in the scope of the management services provided. This agreement expires on June 30, 2020.

Omnibus Agreement

The Partnership has an omnibus agreement with MPC that addresses its payment of a fixed annual fee to MPC for the provision of executive management services by certain executive officers of the general partner and the Partnership's reimbursement of MPC for the provision of certain general and administrative services to it. It also provides for MPC's indemnification of the Partnership for certain matters, including environmental, title and tax matters; as well as our indemnification of MPC for certain matters under this agreement.

Employee Services Agreements

The Partnership has four employee services agreements with MPC. Two of the employee services agreements with MPC were entered into effective October 1, 2012, under which the Partnership reimburses MPC for the provision of certain operational and management services in support of our pipelines, barge dock, butane cavern and tank farms within the L&S segment. Effective December 28, 2015, the Partnership entered into an additional employee services agreement with MPC, which requires that we reimburse MPC for certain operational and management services to us in support of our G&P segment and certain of our other operations. Lastly, we are party to an employee services agreement with MPC dated January 1, 2015, pursuant to which HSM reimburses MPC for employee benefit expenses along with certain operation and management services provided in support of HSM's areas of operation. The agreement is effective until December 31, 2019. Prior to January 1, 2015, this agreement did not exist.

Loan Agreements

On December 4, 2015, the Partnership entered into a loan agreement with MPC Investment LLC ("MPC Investment"), a wholly-owned subsidiary of MPC. Under the terms of the agreement, MPC Investment will make a loan or loans to the Partnership on a revolving basis as requested by the Partnership and as agreed to by MPC Investment, in an amount or amounts that do not result in the aggregate principal amount of all loans outstanding exceeding $500 million at any one time. The entire unpaid principal amount of the loan, together with all accrued and unpaid interest and other amounts (if any), shall become due and payable on December 4, 2020. MPC Investment may demand payment of all or any portion of the outstanding principal amount of the loan, together with all accrued and unpaid interest and other amounts (if any), at any time prior to December 4, 2020. Borrowings under the loan will bear interest at LIBOR plus 1.50 percent. Borrowings were at an average interest rate of 1.939 percent and 1.744 percent, per annum for 2016 and 2015, respectively. In connection with this loan agreement, the Partnership terminated the previous revolving credit agreement of $50 million with MPC, effective December 31, 2015.

During 2016, the Partnership borrowed $2.5 billion and repaid $2.5 billion, resulting in no outstanding balance at December 31, 2016. During 2015, the Partnership borrowed $301 million and repaid $293 million, for an outstanding balance at December 31, 2015 of $8 million, which is included in *Payables to related parties* on the Consolidated Balance Sheets.

Related Party Transactions

The Partnership believes that transactions with related parties were conducted on terms comparable to those with unrelated parties. Related party sales to MPC consisted of crude oil and refined products pipeline transportation services based on regulated tariff rates and storage services based on contracted rates. Related party sales to MPC also consist of revenue related to volume deficiency credits.

Revenue received from related parties related to service and product sales were as follows:

(In millions)	2016	2015	2014
Service revenue			
MPC	$603	$593	$662
Rental income			
MPC	$114	$101	$ 15
Product sales[1]			
MPC	$ 11	$ 1	$—

[1] For 2016 and 2015, there were $46 million and $1 million, respectively, of additional product sales to MPC that net to zero within the consolidated financial statements, as the transactions are recorded net due to the terms of the agreements under which such product was sold. There were no such transactions in 2014.

Related party sales to MPC consist of crude oil and refined products pipeline transportation services based on regulated tariff rates, storage services based on contracted rates and transportation services provided by HSM. Under the Partnership's pipeline transportation services agreements, if MPC fails to transport its minimum throughput volumes during any quarter, then MPC will pay the Partnership a deficiency payment equal to the volume of the deficiency multiplied by the tariff rate then in effect. The deficiency amounts are recorded as *Deferred revenue—related parties* on the Consolidated Balance Sheets. MPC may then apply the amount of any such deficiency payments as a credit for volumes transported on the applicable pipeline system in excess of its minimum volume commitment during the following four or eight quarters under the terms of the applicable transportation services agreement. The Partnership recognizes revenues for the deficiency payments when credits are used for volumes transported in excess of minimum quarterly volume commitments, when it becomes impossible to physically transport volumes necessary to utilize the credits or upon the expiration of the credits. The use or expiration of the credits is a decrease in *Deferred revenue—related parties*.

The revenue received from related parties included in *Other income—related parties* on the Consolidated Statements of Income was as follows:

(In millions)	2016	2015	2014
MPC	$ 60	$ 68	$ 39
MarkWest Utica EMG	16	—	—
Centennial	1	1	1
Ohio Gathering	15	2	—
Ohio Condensate	4	—	—
Other	5	—	—
Total	$101	$ 71	$ 40

MPC provides executive management services and certain general and administrative services to the Partnership under the terms of the omnibus agreement. Expenses incurred under these agreements are shown in the table below by the income statement line where they were recorded. These expenses also include similar charges incurred by HSM for the time period prior to the acquisition and therefore not covered by the omnibus agreement. Charges for services included in *Purchases from related parties* primarily relate to services that support the Partnership's operations and maintenance activities, as well as compensation expenses. Charges for services included in *General and administrative expenses* primarily relate to services that support the Partnership's executive management, accounting and human resources activities. These charges were as follows:

(In millions)	2016	2015	2014
Purchases from related parties	$29	$30	$30
General and administrative expenses	39	46	46
Total	$68	$76	$76

Also under terms of the omnibus agreement, some service costs related to engineering services are associated with assets under construction. These costs added to *Property, plant and equipment* were as follows:

(In millions)	2016	2015	2014
MPC	$38	$13	$8

MPLX LP obtains employee services from MPC under employee services agreements. Expenses incurred under these agreements are shown in the table below by the income statement line where they were recorded. The costs of personnel directly involved in or supporting operations and maintenance activities are classified as *Purchases from related parties* on the Consolidated Balance Sheets. The costs of personnel involved in executive management, accounting and human resources activities are classified as *General and administrative* expenses in the Consolidated Statements of Income.

Employee services expenses from related parties were as follows:

(In millions)	2016	2015	2014
Purchases—related parties	$287	$136	$123
General and administrative expenses	72	22	24
Total	$359	$158	$147

Receivables from related parties which include reimbursements from the MarkWest Merger to be provided by MPC for the conversion of Class B units were as follows:

	December 31,	
(In millions)	2016	2015
MPC	$117	$175
MarkWest Utica EMG	2	4
Ohio Gathering	2	5
Other	1	3
Total	$122	$187

Long-term receivables with related parties, including straight-line rental income for both periods presented, as well as reimbursements from the MarkWest Merger to be provided by MPC for the conversion of Class B units for the period ended December 31, 2015, were as follows:

	December 31,	
(In millions)	2016	2015
MPC	$4	$25

Payables to related parties were as follows:

	December 31,	
(In millions)	2016	2015
MPC	$51	$33
MarkWest Utica EMG	24	21
Total	$75	$54

In recent years, MPC did not ship its minimum committed volumes on certain pipeline systems. In addition, capital projects the Partnership is undertaking at the request of MPC are reimbursed in cash and recognized in income over the remaining term of the applicable transportation services agreements. The *Deferred revenue-related parties* balance associated with the minimum volume deficiencies and project reimbursements were as follows:

	December 31,	
(In millions)	2016	2015
Minimum volume deficiencies—MPC	$44	$36
Project reimbursements—MPC	5	5
Total	$49	$41

7. Net Income (Loss) Per Limited Partner Unit

Net income (loss) per unit applicable to common limited partner units and to subordinated limited partner units is computed by dividing the respective limited partners' interest in net income attributable to MPLX LP by the weighted average number of common units and subordinated units outstanding. Because the Partnership has more than one class of participating securities, it uses the two-class method when calculating the net income per unit applicable to limited partners. The classes of participating securities include common units, subordinated units, general partner units, Preferred units, certain equity-based compensation awards and incentive distribution rights.

The HSM acquisition was a transfer between entities under common control. As an entity under common control with MPC, prior periods were retrospectively adjusted to furnish comparative information. Accordingly, the prior period earnings have been allocated to the general partner and do not affect the net income (loss) per unit calculation. The earnings for HSM will be included in the net income (loss) per unit calculation prospectively as described above.

As discussed further in Note 8, the subordinated units, all of which were owned by MPC, were converted into common units during the third quarter of 2015. For purposes of calculating net income (loss) per unit, the subordinated units were treated as if they converted to common units on July 1, 2015.

In 2016 and 2015, the Partnership had dilutive potential common units consisting of certain equity-based compensation awards and Class B units. Diluted net income per limited partner unit for the 2014 reporting period is the same as basic net income per limited partner unit as there were no potentially dilutive common or subordinated units outstanding as of December 31, 2014.

(In millions)	2016	2015	2014
Net income attributable to MPLX LP	$ 233	$ 156	$121
Less: Distributions declared on Preferred units[(1)]	41	—	—
General partner's distributions declared (including IDRs)[(1)]	205	60	6
Limited partners' distributions declared on common units[(1)]	692	224	54
Limited partner's distributions declared on subordinated units[(1)]	—	31	52
Undistributed net (loss) income attributable to MPLX LP	$(705)	$(159)	$ 9

(1) See Note 8 for information regarding the distribution.

	2016			
(In millions, except per-unit data)	General Partner	Limited Partners' Common Units	Redeemable Preferred Units	Total
Basic and diluted net income attributable to MPLX LP per unit:				
Net income attributable to MPLX LP:				
Distributions declared (including IDRs)	$205	$ 692	$ 41	$ 938
Undistributed net loss attributable to MPLX LP	(14)	(691)	—	(705)
Net income attributable to MPLX LP[(1)]	$191	$ 1	$ 41	$ 233
Weighted average units outstanding:				
Basic	7	331		338
Diluted	7	338		345
Net income attributable to MPLX LP per limited partner unit:				
Basic		$ —		
Diluted		$ —		

(In millions, except per-unit data)	2015 General Partner	Limited Partners' Common Units	Limited Partner's Subordinated Units	Total
Basic and diluted net income attributable to MPLX LP per unit:				
Net income attributable to MPLX LP:				
Distributions declared (including IDRs)	$60	$ 224	$ 31	$ 315
Undistributed net loss attributable to MPLX LP	(3)	(127)	(29)	(159)
Net income attributable to MPLX LP[(1)]	$57	$ 97	$ 2	$ 156
Weighted average units outstanding:				
Basic	2	79	18	99
Diluted	2	80	18	100
Net income attributable to MPLX LP per limited partner unit:				
Basic		$1.23	$0.11	
Diluted		$1.22	$0.11	

(In millions, except per-unit data)	2014 General Partner	Limited Partners' Common Units	Limited Partner's Subordinated Units	Total
Basic and diluted net income attributable to MPLX LP per unit:				
Net income attributable to MPLX LP:				
Distribution declared	$ 6	$ 54	$ 52	$ 112
Undistributed net income attributable to MPLX LP	2	4	3	9
Net income attributable to MPLX LP[(1)]	$ 8	$ 58	$ 55	$ 121
Weighted average units outstanding:				
Basic	2	37	37	76
Diluted	2	37	37	76
Net income attributable to MPLX LP per limited partner unit:				
Basic		$1.55	$1.50	
Diluted		$1.55	$1.50	

(1) Allocation of net income (loss) attributable to MPLX LP assumes all earnings for the period had been distributed based on the current period distribution priorities.

8. Equity

Units Outstanding—The Partnership had 357,193,288 common units outstanding as of December 31, 2016. Of that number, 86,619,313 were owned by MPC, which also owned the two percent general partner interest, represented by 7,371,105 general partner units.

Subordinated Unit Conversion—Following payment of the cash distribution for the second quarter of 2015, the requirements for the conversion of all subordinated units were satisfied under the partnership agreement. As a result, effective August 17, 2015, the 36,951,515 subordinated units owned by MPC were converted into common units on a one-for-one basis and thereafter participate on terms equal with all other common units in distributions of available cash. The conversion did not impact the amount of the cash distributions paid by the Partnership or the total units outstanding.

Reorganization Transactions**—**On September 1, 2016, the Partnership and various affiliates initiated a series of reorganization transactions in order to simplify the Partnership's ownership structure and its financial and tax reporting requirements (the "Class A Reorganization"). In connection with these transactions, all of the issued and outstanding MPLX LP Class A units, all of which were held by MarkWest Hydrocarbon, were either distributed to or purchased by MPC in exchange for $84 million in cash, 21,401,137 MPLX LP common units and 436,758 MPLX LP general partner units. Following these initial transactions, all of the MPLX LP Class A units were exchanged on a one-for-one basis for newly issued common units representing limited partner interests in MPLX LP. MPC also contributed $141 million to facilitate the repayment of intercompany debt between MarkWest Hydrocarbon and MarkWest. As a result of these transactions, the MPLX LP Class A units were eliminated, are no longer outstanding and no longer participate in distributions of cash from the Partnership. Cash that is derived from or attributable to MarkWest Hydrocarbon's operations is now treated in the same manner as cash derived from or attributable to other operations of the Partnership and its subsidiaries.

MarkWest Merger**—**On December 4, 2015, the Partnership completed the MarkWest Merger. As defined in the merger agreement, each common unit of MarkWest issued and outstanding at the effective time of the MarkWest Merger was converted into the right to receive 1.09 common units of MPLX LP. This resulted in the issuance of 216,350,465 common units. The Class A units of MarkWest outstanding immediately prior to the MarkWest Merger were converted into 28,554,313 Class A units of MPLX LP having substantially similar rights and obligations that the Class A units of MarkWest had immediately prior to the combination. Each Class B unit of MarkWest outstanding had immediately prior to the merger converted into the right to receive one Class B unit of MPLX LP having substantially similar rights, including conversion and registration rights, and obligations that the Class B units of MarkWest had immediately prior to the merger. This resulted in the issuance of 7,981,756 MPLX LP Class B units. Each Class B unit of MPLX LP will automatically convert into 1.09 MPLX LP common units and the right to receive $6.20 in cash in equal installments, the first of which occurred on July 1, 2016 and the second of which will occur on July 1, 2017.

ATM Program**—**On August 4, 2016, the Partnership entered into a second amended and restated distribution agreement (the "Distribution Agreement") providing for the continuous issuance of common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings (such continuous offering program, or at-the-market program is referred to as our "ATM Program"). The Partnership expects the net proceeds from sales under the ATM Program will be used for general partnership purposes, including repayment or refinancing of debt, and funding for acquisitions, working capital requirements and capital expenditures. During the year ended December 31, 2015, the Partnership issued an aggregate of 25,166 common units under our ATM Program, generating net proceeds of approximately $1 million. During the year ended December 31, 2016, the Partnership issued an aggregate of 26,347,887 common units under the ATM Program generating net proceeds of approximately $776 million. As of December 31, 2016, $717 million of common units remains available for issuance through the ATM program under the Distribution Agreement.

The table below summarizes the changes in the number of units outstanding for the years ended December 31, 2014, 2015, and 2016:

(In units)	Common	Class B	Subordinated	General Partner	Total
Balance at December 31, 2013	36,951,515	—	36,951,515	1,508,225	75,411,255
Unit-based compensation awards	15,479	—	—	316	15,795
Contribution of interest in Pipe Line Holdings	2,924,104	—	—	59,676	2,983,780
December 2014 equity offering	3,450,000	—	—	70,408	3,520,408
Balance at December 31, 2014	43,341,098	—	36,951,515	1,638,625	81,931,238
Unit-based compensation awards	18,932	—	—	386	19,318
Issuance of units under the ATM program	25,166	—	—	514	25,680
Subordinated unit conversion	36,951,515	—	(36,951,515)	—	—
MarkWest Merger	216,350,465	7,981,756	—	5,160,950	229,493,171
Balance at December 31, 2015	296,687,176	7,981,756	—	6,800,475	311,469,407
Unit-based compensation awards	120,989	—	—	2,470	123,459
Issuance of units under the ATM Program	26,347,887	—	—	537,710	26,885,597
Contribution of HSM (See Note 4)	22,534,002	—	—	459,878	22,993,880
Class B conversion	4,350,057	(3,990,878)	—	7,330	366,509
Class A Reorganization	7,153,177	—	—	(436,758)	6,716,419
Balance at December 31, 2016	357,193,288	3,990,878	—	7,371,105	368,555,271

2016 Activity

On July 1, 2016, 3,990,878 Class B units converted to 4,350,057 common units and received the second quarter distribution. As a result of the Class B units converted to common units during the period, MPLX GP contributed less than $1 million in exchange for 7,330 general partner units to maintain its two percent general partner interest.

As a result of the unit-based compensation awards issued during the period, MPLX GP contributed less than $1 million in exchange for 2,470 general partner units to maintain its two percent general partner interest.

As a result of common units issued under the ATM Program during the period, MPLX GP contributed $16 million in exchange for 537,710 general partner units to maintain its two percent general partner interest.

In connection with the Class A Reorganization, 7 million common units were acquired by MPC that represents the common units received by MPC on the exchange of the MPLX LP Class A units less the units redeemed in the distribution of MPLX Holdings Inc., including the MPLX LP Class A units. Additionally, MPLX LP transferred common units representing a two percent ownership interest of MPLX Holdings Inc. to MPLX GP in exchange for 436,758 MPLX LP general partner units held by MPLX GP, as discussed above.

2015 Activity

As a result of common units issued under the ATM Program during 2015, MPLX GP contributed less than $1 million in exchange for 514 general partner units to maintain its two percent general partner interest.

In connection with the MarkWest Merger discussed in Note 4, MPLX GP contributed $169 million in exchange for 5,160,950 general partner units to maintain its two percent general partner interest.

2014 Activity

Effective December 1, 2014, as discussed in Note 4, the Partnership accepted a contribution of 7.625 percent of outstanding partnership interests of Pipe Line Holdings from subsidiaries of MPC in exchange for the issuance of equity valued at $200 million. The equity consideration consisted of 2,924,104 MPLX LP common units and was calculated by dividing $200 million by the average closing price for MPLX LP common units for the ten trading days preceding December 1, 2014, which was $68.397.

On December 8, 2014, the Partnership closed an equity offering of 3,450,000 common units at a public offering price of $66.68 per unit. The Partnership used the net proceeds of $221 million to repay borrowings under its revolving credit facility and for general partnership purposes.

As a result of the contribution mentioned above and the December 2014 equity offering, MPLX GP contributed $9 million in exchange for 130,084 general partner units to maintain its two percent general partnership interest.

Issuance of Additional Securities—The partnership agreement authorizes the Partnership to issue an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by the general partner without the approval of the unitholders.

Incentive Distribution Rights—The following table illustrates the percentage allocations of available cash from operating surplus between the common and subordinated unitholders and the general partner based on the specified target distribution levels. The amounts set forth under "Marginal percentage interest in distributions" are the percentage interests of the general partner and common and subordinated unitholders in any available cash from operating surplus the Partnership distributes up to and including the corresponding amount in the column "Total quarterly distribution per unit target amount." The percentage interests shown for its common and subordinated unitholders and the general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for the general partner include its two percent general partner interest and assume that the general partner has contributed any additional capital necessary to maintain its two percent general partner interest, the general partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

Net Income Allocation—In preparing the Consolidated Statements of Equity, net income (loss) attributable to MPLX LP is allocated to Preferred unitholders based on a fixed distribution schedule, as discussed in Note 9, and subsequently allocated to the general partner and limited partner unitholders. However, when distributions related to the incentive distribution rights are made, earnings equal to the amount of those distributions are first allocated to the general partner before the remaining earnings are allocated to the limited partner unitholders based on their respective ownership percentages. The following table presents the allocation of the general partner's interest in net income attributable to MPLX LP:

(In millions)	2016	2015	2014
Net income attributable to MPLX LP	$233	$156	$121
Less: Preferred unit distributions	41	—	—
General partner's incentive distribution rights and other	191	55	4
Net income attributable to MPLX LP available to general and limited partners	$ 1	$101	$117
General partner's two percent interest in net income attributable to MPLX LP	$—	$ 2	$ 2
General partner's incentive distribution rights and other	191	55	4
General partner's interest in net income attributable to MPLX LP	$191	$ 57	$ 6

Cash distributions—The partnership agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the common unitholders and general partner will receive. In accordance with the partnership agreement, on January 25, 2017, the Partnership declared a quarterly cash distribution, based on the results of the fourth quarter of 2016, totaling $242 million, or $0.5200 per unit. This distribution was paid on February 14, 2017 to unitholders of record on February 6, 2017. See the table below for the IDR impact for 2016.

The allocation of total quarterly cash distributions to general, limited, and Preferred unitholders is as follows for the years ended December 31, 2016, 2015 and 2014. The distributions are declared subsequent to quarter end; therefore, the following table represents total cash distributions applicable to the period in which the distributions were earned.

(In millions)	2016	2015	2014
General partner's distributions:			
General partner's distributions	$ 18	$ 6	$ 2
General partner's incentive distribution rights distributions	187	54	4
Total general partner's distributions	205	60	6
Limited partners' distributions:			
Common unitholders	692	224	54
Subordinated unitholders	—	31	52
Total limited partners' distributions	692	255	106
Preferred unit distributions	41	—	—
Total cash distributions declared	$938	$315	$112

9. Redeemable Preferred Units

Private Placement of Preferred Units—On May 13, 2016, MPLX LP completed the private placement of approximately 30.8 million 6.5 percent Series A Convertible Preferred units (the "Preferred units") for a cash purchase price of $32.50 per unit. The aggregate net proceeds of approximately $984 million from the sale of the Preferred units were used for capital expenditures, repayment of debt and general partnership purposes.

The Preferred units rank senior to all common units with respect to distributions and rights upon liquidation. The holders of the Preferred units are entitled to receive cumulative quarterly distributions equal to $0.528125 per unit commencing for the quarter ended June 30, 2016, with a prorated amount from the date of issuance. Following the second anniversary of the issuance of the Preferred units, the holders of the Preferred units will receive as a distribution the greater of $0.528125 per unit or the amount of per unit distributions paid to common units. Since the Preferred unit distribution was declared subsequent to the end of the second quarter of 2016, the distribution was not accrued to the Preferred unitholders' capital account. For the quarter ended June 30, 2016, the Preferred units received an earned aggregate cash distribution of $9 million, based on the quarterly per unit distribution prorated for the 49-day period the Preferred units were outstanding during the second quarter of 2016.

The changes in the redeemable preferred balance for 2016 were as follows:

(In millions)	Redeemable Preferred Units
Issuance of MPLX LP redeemable Preferred units on May 13, 2016	$ 984
Net income allocated for May 13, 2016 through December 31, 2016	41
Distributions received by Preferred unitholders	(25)
Balance at December 31, 2016	$1,000

The purchasers may convert their Preferred units into common units, at any time after the third anniversary of the issuance date or prior to liquidation, dissolution or winding up of the Partnership, in full or in part, subject to minimum conversion amounts and conditions. After the fourth anniversary of the issuance date, the Partnership may convert the Preferred units into common units at any time, in whole or in part, subject to certain minimum conversion amounts and conditions, if the closing price of MPLX LP common units is greater than $48.75 for the 20 day trading period immediately preceding the conversion notice date. The conversion rate for the Preferred units shall be the quotient of (a) the sum of (i) $32.50, plus (ii) any unpaid cash distributions on the applicable Preferred unit, divided by (b) $32.50. The holders of the Preferred units are entitled to vote on an as-converted basis with the common unitholders and will have certain other class voting rights with respect to any amendment to the partnership agreement that would adversely affect any rights, preferences or privileges of the Preferred units. In addition, upon certain events involving a change in control the holders of Preferred units may elect, among other potential elections, to convert their Preferred units to common units at the then change of control conversion rate.

The Preferred units are considered redeemable securities under GAAP due to the existence of redemption provisions upon a deemed liquidation event which is outside the Partnership's control. Therefore they are presented as temporary equity in the mezzanine section of the Consolidated Balance Sheets. The Preferred units have been recorded at their issuance date fair value, net of issuance costs. Income allocations increase the carrying value, and declared distributions decreased the carrying value of the Preferred units. Because the Preferred units are not currently redeemable and not probable of becoming redeemable, adjustment to the initial carrying amount is not necessary and would only be required if it becomes probable that the Preferred units would become redeemable.

10. Segment Information

The Partnership's chief operating decision maker is the chief executive officer ("CEO") of its general partner. The CEO reviews the Partnership's discrete financial information, makes operating decisions, assesses financial performance and allocates resources on a type of service basis. The Partnership has two reportable segments: L&S and G&P. Each of these segments is organized and managed based upon the nature of the products and services it offers.

- L&S—transports and stores crude oil and refined petroleum products. Segment information for prior periods includes HSM as it is an entity under common control.
- G&P—gathers, processes and transports natural gas; gathers, transports, fractionates, stores and markets NGLs. This segment is the result of the MarkWest Merger on December 4, 2015 discussed in more detail in Note 4. Segment information for periods prior to the MarkWest Merger does not include amounts for these operations.

The Partnership has investments in entities that are accounted for using the equity method of accounting (see Note 5). However, the CEO views the Partnership-operated equity method investments' financial information as if those investments were consolidated.

Segment operating income represents income from operations attributable to the reportable segments. Corporate general and administrative expenses, unrealized derivative (losses) gains, property, plant and equipment, goodwill impairment and depreciation and amortization are not allocated to the reportable segments. Management does not consider these items allocable to or controllable by any individual segment and, therefore, excludes these items when evaluating segment performance. Segment results are also adjusted to exclude the portion of income from operations attributable to the noncontrolling interests related to partially-owned entities that are either consolidated or accounted for as equity method investments. Segment operating income attributable to MPLX LP excludes the operating income related to the Predecessor of the inland marine business prior to the March 31, 2016 acquisition.

The tables below present information about income from operations and capital expenditures for the reported segments:

(In millions)	2016 L&S	2016 G&P	2016 Total
Revenues and other income:			
Segment revenues	$787	$2,185	$2,972
Segment other income	68	1	69
Total segment revenues and other income	855	2,186	3,041
Costs and expenses:			
Segment cost of revenues	368	907	1,275
Segment operating income before portion attributable to noncontrolling interest and Predecessor	487	1,279	1,766
Segment portion attributable to noncontrolling interest and Predecessor	34	147	181
Segment operating income attributable to MPLX LP	$453	$1,132	$1,585

(In millions)	2015 L&S	2015 G&P	2015 Total
Revenues and other income:			
Segment revenues	$760	$ 150	$ 910
Segment other income	75	—	75
Total segment revenues and other income	835	150	985
Costs and expenses:			
Segment cost of revenues	379	62	441
Segment operating income before portion attributable to noncontrolling interest and Predecessor	456	88	544
Segment portion attributable to noncontrolling interest and Predecessor	134	12	146
Segment operating income attributable to MPLX LP	$322	$ 76	$ 398

(In millions)	2014 L&S
Revenues and other income:	
Segment revenues	$ 747
Segment other income	46
Total segment revenues and other income	793
Costs and expenses:	
Segment cost of revenues	392
Segment operating income before portion attributable to noncontrolling interest and Predecessor	401
Segment portion attributable to noncontrolling interest and Predecessor	188
Segment operating income attributable to MPLX LP	$ 213

(in millions)	2016	2015	2014
Reconciliation to Income from operations:			
L&S segment operating income attributable to MPLX LP	$ 453	$ 322	$213
G&P segment operating income attributable to MPLX LP	1,132	76	—
Segment operating income attributable to MPLX LP	1,585	398	213
Segment portion attributable to unconsolidated affiliates	(173)	(8)	85
Segment portion attributable to Predecessor	34	133	103
(Loss) income from equity method investments	(74)	3	—
Other income—related parties	40	2	—
Unrealized derivative (losses) gains[(1)]	(36)	4	—
Depreciation and amortization	(546)	(116)	(75)
Impairment expense	(130)	—	—
General and administrative expenses	(193)	(118)	(81)
Income from operations	$ 507	$ 298	$245

(in millions)	2016	2015	2014
Reconciliation to Total revenues and other income:			
Total segment revenues and other income	$3,041	$985	$793
Revenue adjustment from unconsolidated affiliates	(402)	(28)	—
(Loss) income from equity method investments	(74)	3	—
Other income—related parties	40	2	—
Unrealized derivative losses[(1)]	(15)	(1)	—
Total revenues and other income	$2,590	$961	$793

(in millions)	2016	2015	2014
Reconciliation to Net income attributable to noncontrolling interests and Predecessor:			
Segment portion attributable to noncontrolling interest and Predecessor	$ 181	$146	$188
Portion of noncontrolling interests and Predecessor related to items below segment income from operations	(124)	(48)	(70)
Portion of operating income attributable to noncontrolling interests of unconsolidated affiliates	(32)	(5)	—
Net income attributable to noncontrolling interests and Predecessor	$ 25	$ 93	$118

(1) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record the realized gain or loss of the contract.

The following reconciles segment capital expenditures to total capital expenditures:

(In millions)	2016	2015	2014
L&S segment capital expenditures	$ 443	$212	$141
G&P segment capital expenditures	894	100	—
Total segment capital expenditures	1,337	312	141
Less: Capital expenditures for Partnership-operated, non-wholly-owned subsidiaries in G&P segment	131	24	—
Total capital expenditures	$1,206	$288	$141

Total assets by reportable segment were:

(In millions)	December 31, 2016	2015
Cash and cash equivalents	$ 234	$ 43
L&S	2,115	1,842
G&P	14,297	14,219
Total assets	$16,646	$16,104

11. Major Customers and Concentration of Credit Risk

MPC accounted for 30 percent, 79 percent and 90 percent of the Partnership's total revenues and other income for 2016, 2015 and 2014, respectively, excluding revenues attributable to volumes shipped by MPC under joint tariffs with third parties, which are treated as third-party revenue for accounting purposes.

A second customer accounted for 12 percent of the Partnership's total revenues and other income for 2016. Revenues from this customer are from product sales, gathering, processing and fractionation services in the G&P segment. As of December 31, 2016, the Partnership had $59 million of accounts receivable from this customer.

A third customer accounted for 10 percent of the Partnership's total revenues and other income for 2016. Revenues from this customer are from product sales, processing and fractionation services in the G&P segment. As of December 31, 2016, the Partnership had $13 million of accounts receivable from this customer.

The Partnership has a concentration of trade receivables due from customers in the same industry, MPC, integrated oil companies, independent refining companies and other pipeline companies. These concentrations of customers may impact the Partnership's overall exposure to credit risk as they may be similarly affected by changes in economic, regulatory and other factors. The Partnership manages its exposure to credit risk through credit analysis, credit limit approvals and monitoring procedures, and for certain transactions, it may request letters of credit, prepayments or guarantees.

12. Income Tax

The Partnership is not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on the Partnership's net income generally are borne by its partners through the allocation of taxable income. The Partnership's income tax (benefit) provision results from partnership activity in the states of Texas, Ohio and Tennessee.

As a result of the Class A Reorganization discussed in Note 8, MarkWest Hydrocarbon (MarkWest Hydrocarbon, Inc. prior to the Class A Reorganization) is no longer a tax paying entity for federal income tax purposes or for the majority of states that impose an income tax effective September 1, 2016. After MarkWest Hydrocarbon files its 2016 income tax returns in 2017, the Partnership anticipates a residual tax provision to be recorded. In connection with the Class A Reorganization, MPC assumed $377 million of MPLX LP's deferred tax liabilities.

The Partnership and MarkWest Hydrocarbon recorded income tax expense of $12 million, $1 million and $1 million for the years ended December 31, 2016, 2015 and 2014, respectively. The effective tax rate was five percent for 2016, and less than one percent for 2015 and 2014, respectively.

The components of the provision for income tax expense (benefit) are as follows:

(In millions)	December 31, 2016	2015
Current income tax expense:		
Federal	$ 4	$—
State	1	—
Total current	5	—
Deferred income tax (benefit) expense:		
Federal	(16)	3
State	(1)	(2)
Total deferred	(17)	1
(Benefit) provision for income tax	$(12)	$ 1

A reconciliation of the (benefit) provision for income tax and the amount computed by applying the federal statutory rate of 35 percent to the income before income taxes for each of the years ended December 31, 2016 and 2015 is as follows:

	December 31, 2016			
(In millions)	MarkWest Hydrocarbon[(1)]	Partnership	Eliminations	Consolidated
(Loss) income before (benefit) provision for income tax	$(41)	$285	$ 2	$246
Federal statutory rate	35%	— %	— %	
Federal income tax at statutory rate	(14)	—	—	(14)
State income taxes net of federal benefit	(2)	1	—	(1)
Provision on income from MPLX LP Class A units	3	—	—	3
Change in state statutory rate	(1)	—	—	(1)
Other	1	—	—	1
(Benefit) provision for income tax	$(13)	$ 1	$—	$ (12)

	December 31, 2015			
(In millions)	MarkWest Hydrocarbon[(1)]	Partnership	Eliminations	Consolidated
Income before provision (benefit) for income tax	$ 9	$240	$ 1	$250
Federal statutory rate	35%	— %	— %	
Federal income tax at statutory rate	3	—	—	3
State income taxes net of federal benefit	—	(2)	—	(2)
Provision on income from MPLX LP Class A units	1	—	—	1
Other	(1)	—	—	(1)
Provision (benefit) for income tax	$ 3	$ (2)	$—	$ 1

(1) MarkWest Hydrocarbon paid tax on its share of the Partnership's income or loss as a result of its ownership of MPLX LP Class A units through September 1, 2016.

Deferred tax assets and liabilities consist of the following:

(In millions)	December 31, 2016	2015
Deferred tax assets:		
Derivatives	$—	$ 9
Net operating loss carryforwards	—	62
Total deferred tax assets	—	71
Deferred tax liabilities:		
Property, plant and equipment	5	7
Investments in subsidiaries and affiliates	—	442
Total deferred tax liabilities	5	449
Net deferred tax liabilities	$ 5	$378

At December 31, 2016, MarkWest Hydrocarbon had no tax-effected federal or state operating loss carryforwards. These were assumed by MPC on September 1, 2016 in connection with the Class A Reorganization discussed in Note 8.

Significant judgment is required in evaluating tax positions and determining the Partnership and MarkWest Hydrocarbon's provision for income taxes. During the ordinary course of business, there may be transactions and calculations for which the ultimate tax determination is uncertain. However, the Partnership and MarkWest Hydrocarbon did not have any material uncertain tax positions for the years ended December 31, 2016, 2015 or 2014.

Any interest and penalties related to income taxes were recorded as a part of the provision for income taxes. Such interest and penalties were a net expense of less than $1 million in 2016 and 2015, respectively, and a net benefit of less than $1 million in 2014. As of December 31, 2016 and 2015, less than $1 million, respectively, of interest and penalties were accrued related to income taxes. In addition, the Partnership and MarkWest Hydrocarbon's former corporate entity have federal tax years 2013 through 2015 and state tax years 2012 through 2015 open to examination.

13. Inventories

Inventories consist of the following:

(In millions)	December 31, 2016	2015
NGLs	$ 2	$ 3
Line fill	9	5
Spare parts, materials and supplies	43	43
Total inventories	$ 54	$ 51

14. Property, Plant and Equipment

Property, plant and equipment with associated accumulated depreciation is shown below:

(In millions)	Estimated Useful Lives	December 31, 2016	December 31, 2015
Natural gas gathering and NGL transportation pipelines and facilities	5 - 30 years	$ 4,748	$ 4,307
Processing, fractionation and storage facilities	25 - 30 years	3,467	3,185
Pipelines and related assets	19 - 42 years	1,492	1,128
Barges and towing vessels	20 years	479	475
Land, building, office equipment and other	3 - 30 years	701	606
Construction-in-progress		958	946
Total		11,845	10,647
Less accumulated depreciation		1,115	650
Property, plant and equipment, net		$10,730	$ 9,997

Property, plant and equipment includes gross assets acquired under capital leases of approximately $25 million at December 31, 2016 and 2015, respectively, with related amounts in accumulated depreciation of approximately $8 million and $7 million at December 31, 2016 and 2015, respectively.

15. Fair Value Measurements

Fair Values—Recurring

Fair value measurements and disclosures relate primarily to the Partnership's derivative positions as discussed in Note 16. As part of the MarkWest Merger, the MarkWest opening balance sheet was valued at fair value (see Note 4).

Money market funds, which are included in *Cash and cash equivalents* on the Consolidated Balance Sheets, are measured at fair value and are included in Level 1 measurements of the valuation hierarchy. The derivative contracts are measured at fair value on a recurring basis and classified within Level 2 and Level 3 of the valuation hierarchy. The Level 2 and Level 3 measurements are obtained using a market approach. LIBOR rates are an observable input for the measurement of all derivative contracts. The measurements for all commodity contracts contain observable inputs in the form of forward prices based on WTI crude oil prices; and Columbia Appalachia, Henry Hub, PEPL and Houston Ship Channel natural gas prices. Level 2 instruments include crude oil and natural gas swap contracts. The valuations are based on the appropriate commodity prices and contain no significant unobservable inputs. Level 3 instruments include all NGL transactions and embedded derivatives in commodity contracts. The significant unobservable inputs for NGL transactions and embedded derivatives in commodity contracts include NGL prices interpolated and extrapolated due to inactive markets, electricity price curves, and probability of renewal. The following table presents the financial instruments carried at fair value classified by the valuation hierarchy:

(In millions)	December 31, 2016 Assets	December 31, 2016 Liabilities	December 31, 2015 Assets	December 31, 2015 Liabilities
Significant other observable inputs (Level 2)				
Commodity contracts	$—	$—	$ 2	$ —
Significant unobservable inputs (Level 3)				
Commodity contracts	—	(6)	7	—
Embedded derivatives in commodity contracts	—	(54)	—	(32)
Total carrying value in Consolidated Balance Sheets	$—	$ (60)	$ 9	$ (32)

The following table provides additional information about the significant unobservable inputs used in the valuation of Level 3 instruments as of December 31, 2016. The market approach is used for valuation of all instruments.

Level 3 Instrument	Balance Sheet Classification	Unobservable Inputs	Value Range	Time Period
Commodity contracts	Liabilities	Forward ethane prices (per gallon)[1]	\$0.28 - \$0.31	Jan. 17 - Dec. 17
		Forward propane prices (per gallon)[1]	\$0.66 - \$0.72	Jan. 17 - Dec. 17
		Forward isobutane prices (per gallon)[1]	\$0.85 - \$0.97	Jan. 17 - Dec. 17
		Forward normal butane prices (per gallon)[1]	\$0.79 - \$0.93	Jan. 17 - Dec. 17
		Forward natural gasoline prices (per gallon)[1]	\$1.16 - \$1.24	Jan. 17 - Dec. 17
Embedded derivatives in commodity contracts	Liabilities	Forward propane prices (per gallon)[1]	\$0.62 - \$0.72	Jan. 17 - Dec. 22
		Forward isobutane prices (per gallon)[1]	\$0.82 - \$0.97	Jan. 17 - Dec. 22
		Forward normal butane prices (per gallon)[1]	\$0.78 - \$0.93	Jan. 17 - Dec. 22
		Forward natural gasoline prices (per gallon)[1]	\$1.16 - \$1.27	Jan. 17 - Dec. 22
		Forward natural gas prices (per mmbtu)[2]	\$2.37 - \$3.72	Jan. 17 - Dec. 22
		Probability of renewal[3]	50.0%	
		Probability of renewal for second 5-yr term[3]	75.0%	

(1) NGL prices used in the valuations decrease in the early years and increase over time.

(2) Natural gas prices used in the valuations are higher in the early years and decrease over time.

(3) The producer counterparty to the embedded derivative has the option to renew the gas purchase agreement and the related keep-whole processing agreement for two successive five-year terms after 2022. The embedded gas purchase agreement cannot be renewed without the renewal of the related keep-whole processing agreement. Due to the significant number of years until the renewal options are exercisable and the high level of uncertainty regarding the counterparty's future business strategy, the future commodity price environment, and the future competitive environment for midstream services in the Southern Appalachian region, management determined that a 50 percent probability of renewal for the first five-year term and 75 percent for the second five-year term are appropriate assumptions. Included in this assumption is a further extension of management's estimates of future frac spreads through 2032.

Fair Value Sensitivity Related to Unobservable Inputs

Commodity contracts (assets and liabilities)—For the Partnership's commodity contracts, increases in forward NGL prices result in a decrease in the fair value of the derivative assets and an increase in the fair value of the derivative liabilities. The forward prices for the individual NGL products generally increase or decrease in a positive correlation with one another.

Embedded derivatives in commodity contracts—The Partnership has a single embedded derivative liability comprised of both the purchase of natural gas at prices impacted by the frac spread and the probability of contract renewal (the "Natural Gas Embedded Derivative"), as discussed further in Note 16. Increases (decreases) in the frac spread result in an increase (decrease) in the fair value of the embedded derivative liability. An increase in the probability of renewal would result in an increase in the fair value of the related embedded derivative liability.

Embedded derivatives in utility contracts—The Partnership had an embedded derivative contract that fixed a component of the utilities costs at a plant in the Southwest operations to an index price of electricity which expired as of December 31, 2016. Increases (decreases) in the index price for electricity resulted in a decrease (increase) in the realized losses presented in Cost of Revenues on the Income Statement.

Level 3 Valuation Process

The Partnership's Risk Management Department (the "Risk Department") is responsible for the valuation of the Partnership's commodity derivative contracts and embedded derivatives in commodity contracts, except for the Natural Gas Embedded Derivative. The Risk Department reports to the Chief Financial Officer and is responsible for the oversight of the Partnership's commodity risk management program. The members of the Risk Department have the requisite experience, knowledge and day-to-day involvement in the energy commodity markets to ensure appropriate valuations and understand the changes in the valuations from period to period. The valuations of the Level 3 commodity derivative contracts are performed by a third-party pricing service and reviewed and validated on a quarterly basis by the Risk Department by comparing the pricing and option volatilities to actual market data and/or data provided by at least one other independent third-party pricing service.

Management is responsible for the valuation of the Natural Gas Embedded Derivative discussed in Note 16. Included in the valuation of the Natural Gas Embedded Derivative are assumptions about the forward price curves for NGLs and natural gas for periods in which price curves are not available from third-party pricing services due to insufficient market data. The Risk Department must develop forward price curves for NGLs and natural gas through the initial contract term (January 2017 through December 2022) for management's use in determining the fair value of the Natural Gas Embedded Derivative. In developing the pricing curves for these periods, the Risk Department maximizes its use of the latest known market data and trends as well as its understanding of the historical relationships between forward NGL and natural gas prices and the forward market data that is available for the required period, such as crude oil pricing and natural gas pricing from other markets. However, there is very limited actual market data available to validate the Risk Department's estimated price curves. Management also assesses the probability of the producer customer's renewal of the contracts, which includes consideration of:

- The estimated favorability of the contracts to the producer customer as compared to other options that would be available to them at the time and in the relative geographic area of their producing assets.
- Extrapolated pricing curves, using a weighted average probability method that is based on historical frac spreads, which impact the calculation of favorability.
- The producer customer's potential business strategy decision points that may exist at the time the counterparty would elect whether to renew the contracts.

Changes in Level 3 Fair Value Measurements

The tables below include a roll forward of the balance sheet amounts for the years ended December 31, 2016 and 2015 (including the change in fair value) for assets and liabilities classified by the Partnership within Level 3 of the valuation hierarchy, except for the changes in goodwill. See Note 5 for detail of the Ohio Condensate equity method impairment charge, which included a Level 3 valuation adjustment for the year ended December 31, 2016. See Note 18 for a rollforward of goodwill, which included a Level 3 valuation adjustment for the year ended December 31, 2016.

	2016		2015	
(In millions)	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)
Fair value at beginning of period	$ 7	$ (32)	$—	$—
Net positions assumed in conjunction with the MarkWest Merger	—	—	7	(38)
Total (loss) gain (realized and unrealized) included in earnings[(1)]	(13)	(29)	3	5
Settlements	—	7	(3)	1
Fair value at end of period	$ (6)	$ (54)	$ 7	$ (32)
The amount of total (losses) gains for the period included in earnings attributable to the change in unrealized gains or losses relating to liabilities still held at end of period	$ (6)	$ (26)	$ 2	$ 5

(1) Gains and losses on Commodity Derivative Contracts classified as Level 3 are recorded in *Product sales* in the accompanying Consolidated Statements of Income. Gains and losses on Embedded Derivatives in Commodity Contracts are recorded in *Cost of revenues* and *Purchased product costs*.

Fair Values—Reported

The Partnership's primary financial instruments are cash and cash equivalents, receivables, receivables from related parties, accounts payable, payables to related parties and long-term debt. The Partnership's fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) MPC's investment-grade credit rating and (3) the historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk. The Partnership believes the carrying values of its current assets and liabilities approximate fair value. The recorded value of the amounts outstanding under the bank revolving credit facility, if any, approximates fair value due to the variable interest rate that approximates current market rates. Derivative instruments are recorded at fair value, based on available market information (see Note 16).

The SMR liability and $4.1 billion aggregate principal of the Partnership's long-term debt were recorded at fair value in connection with the MarkWest Merger as of December 4, 2015, which established a new cost basis for each of those liabilities. The fair value of the long-term debt is estimated based on recent market non-binding indicative quotes. The fair value of the SMR liability is estimated using a discounted cash flow approach based on the contractual cash flows and the Partnership's unsecured borrowing rate. The long-term debt and SMR liability fair values are considered Level 3 measurements.

The following table summarizes the fair value and carrying value of the Partnership's long-term debt, excluding capital leases, and SMR liability.

	December 31,			
	2016		2015	
(In millions)	Fair Value	Carrying Value	Fair Value	Carrying Value
Long-term debt	$4,953	$4,422	$5,212	$5,255
SMR liability	$ 108	$ 96	$ 99	$ 100

16. Derivative Financial Instruments

Commodity Derivatives

NGL and natural gas prices are volatile and are impacted by changes in fundamental supply and demand, as well as market uncertainty, availability of NGL transportation and fractionation capacity and a variety of additional factors that are beyond the Partnership's control. The Partnership's profitability is directly affected by prevailing commodity prices primarily as a result of processing or conditioning at its own or third-party processing plants, purchasing and selling or gathering and transporting volumes of natural gas at index-related prices and the cost of third-party transportation and fractionation services. To the extent that commodity prices influence the level of natural gas drilling by the Partnership's producer customers, such prices also affect profitability. To protect itself financially against adverse price movements and to maintain more stable and predictable cash flows so that the Partnership can meet its cash distribution objectives, debt service and capital plans, the Partnership executes a strategy governed by its risk management policy. The Partnership has a committee comprised of senior management that oversees risk management activities, continually monitors the risk management program and adjusts its strategy as conditions warrant. The Partnership enters into certain derivative contracts to reduce the risks associated with unfavorable changes in the prices of natural gas and NGLs. Derivative contracts utilized are swaps traded on the OTC market and fixed price forward contracts. The risk management policy does not allow the Partnership to take speculative positions with its derivative contracts.

To mitigate its cash flow exposure to fluctuations in the price of NGLs, the Partnership has entered into derivative financial instruments relating to the future price of NGLs and crude oil. The Partnership currently manages the majority of its NGL price risk using direct product NGL derivative contracts. The Partnership enters into NGL derivative contracts when adequate market liquidity exists and future prices are satisfactory. A portion of the Partnership's NGL price exposure is managed by using crude oil contracts. In periods where NGL prices and crude oil prices are not consistent with the historical relationship, the crude oil contracts create increased risk and additional gains or losses. The Partnership may settle its crude oil contracts prior to the contractual settlement date in order to take advantage of favorable terms and reduce the future exposure resulting from the less effective crude oil contracts. Based on its current volume forecasts, the majority of its derivative positions used to manage the future commodity price exposure are expected to be direct product NGL derivative contracts.

To mitigate its cash flow exposure to fluctuations in the price of natural gas, the Partnership primarily utilizes derivative financial instruments relating to the future price of natural gas and takes into account the partial offset of its long and short gas positions resulting from normal operating activities.

As a result of its current derivative positions, the Partnership has mitigated a portion of its expected commodity price risk through the fourth quarter of 2017. The Partnership would be exposed to additional commodity risk in certain situations such as if producers under deliver or over deliver product or when processing facilities are operated in different recovery modes. In the event the Partnership has derivative positions in excess of the product delivered or expected to be delivered, the excess derivative positions may be terminated.

Management conducts a standard credit review on counterparties to derivative contracts, and has provided the counterparties with a guaranty as credit support for its obligations. A separate agreement with certain counterparties allows MarkWest Liberty Midstream to enter into derivative positions without posting cash collateral. The Partnership uses standardized agreements that allow for offset of certain positive and negative exposures (“master netting arrangements”) in the event of default or other terminating events, including bankruptcy.

The Partnership records derivative contracts at fair value in the Consolidated Balance Sheets and has not elected hedge accounting or the normal purchases and normal sales designation (except for electricity and certain other qualifying contracts, for which the normal purchases and normal sales designation has been elected). The Partnership’s accounting may cause volatility in the Consolidated Statements of Income as the Partnership recognizes in current earnings all unrealized gains and losses from the changes in fair value of derivatives. The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record the realized gain or loss of the contract.

Volume of Commodity Derivative Activity

As of December 31, 2016, the Partnership had the following outstanding commodity contracts that were executed to manage the cash flow risk associated with future sales of NGLs:

Derivative contracts not designated as hedging instruments	Financial Position	Notional Quantity (net)
Crude Oil (bbl)	Short	36,500
Natural Gas (MMBtu)	Long	297,017
NGLs (gal)	Short	64,211,702

Embedded Derivatives in Commodity Contracts

The Partnership has a commodity contract with a producer customer in the Southern Appalachian region that creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The commodity contract is a component of a broader regional arrangement that also includes a keep-whole processing agreement. For accounting purposes, these contracts have been aggregated into a single contract and are evaluated together. In February 2011, the Partnership executed agreements with the producer customer to extend the commodity contract and the related processing agreement from March 31, 2015 to December 31, 2022, with the producer customer’s option to extend the agreement for two successive five year terms through December 31, 2032. The purchase of gas at prices based on the frac spread and the option to extend the agreements have been identified as a single embedded derivative, which is recorded at fair value. The probability of renewal is determined based on extrapolated pricing curves, a review of the overall expected favorability of the contracts based on such pricing curves, and assumptions about the counterparty’s potential business strategy decision points that may exist at the time the counterparty would elect whether to renew the contract. The changes in fair value of this embedded derivative are based on the difference between the contractual and index pricing, the probability of the producer customer exercising its option to extend and the estimated favorability of these contracts compared to current market conditions. The changes in fair value are recorded in earnings through *Purchased product costs* in the Consolidated Statements of Income. As of December 31, 2016 and 2015, the estimated fair value of this contract was a liability of $54 million and $31 million, respectively.

During the years ended December 31, 2016 and 2015, the Partnership had a commodity contract that allowed for the Partnership to fix a component of the utilities cost to an index price on electricity at a plant location in the Southwest Operations which expired as of December 31, 2016. Changes in the fair value of the derivative component of this contract were recognized as *Cost of revenues* in the Consolidated Statements of Income. As of December 31, 2015, the estimated fair value of this contract was a liability of $1 million.

Financial Statement Impact of Derivative Contracts

Certain derivative positions are subject to master netting agreements, therefore the Partnership has elected to offset derivative assets and liabilities that are legally permissible to be offset. As of December 31, 2016 and 2015, there were no derivative assets or liabilities that were offset in the Consolidated Balance Sheets. The impact of the Partnership's derivative instruments on its Consolidated Balance Sheets is summarized below:

(In millions)	December 31, 2016		December 31, 2015	
Derivative contracts not designated as hedging instruments and their balance sheet location	Asset	Liability	Asset	Liability
Commodity contracts[1]				
Other current assets / other current liabilities	$—	$(13)	$ 9	$ (5)
Other noncurrent assets / deferred credits and other liabilities	—	(47)	—	(27)
Total	$—	$(60)	$ 9	$(32)

(1) Includes embedded derivatives in commodity contracts as discussed above.

In the table above, the Partnership does not offset a counterparty's current derivative contracts with the counterparty's non-current derivative contracts, although the Partnership's master netting arrangements would allow current and non-current positions to be offset in the event of default. Additionally, in the event of a default, the Partnership's master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions and other forms of non-cash collateral (such as letters of credit).

The impact of the Partnership's derivative contracts not designated as hedging instruments and the location of gain or (loss) recognized in the Consolidated Statements of Income is summarized below:

	December 31,	
(In millions)	2016	2015
Product sales		
Realized gain	$ 2	$ 4
Unrealized loss	(15)	(1)
Total revenue: derivative (loss) gain from product sales	(13)	3
Purchased product costs		
Realized loss	(5)	—
Unrealized (loss) gain	(22)	5
Total purchased product costs: derivative (loss) gain from product purchases	(27)	5
Cost of revenues		
Realized loss	(3)	—
Unrealized gain	1	—
Total cost of revenues: derivative loss from cost of revenues	(2)	—
Total derivative (losses) gains	$ (42)	$ 8

17. Debt

The Partnership's outstanding borrowings at December 31, 2016 and 2015 consisted of the following:

(In millions)	December 31, 2016	December 31, 2015
MPLX LP:		
Bank revolving credit facility due 2020	$ —	$ 877
Term loan facility due 2019	250	250
5.500% senior notes due 2023	710	710
4.500% senior notes due 2023	989	989
4.875% senior notes due 2024	1,149	1,149
4.000% senior notes due 2025	500	500
4.875% senior notes due 2025	1,189	1,189
Consolidated subsidiaries:		
MarkWest—4.500%—5.500% senior notes, due 2023—2025	63	63
MPL—capital lease obligations due 2020	8	9
Total	4,858	5,736
Unamortized debt issuance costs	(7)	(8)
Unamortized discount[1]	(428)	(472)
Amounts due within one year	(1)	(1)
Total long-term debt due after one year	$4,422	$5,255

(1) Includes $420 million and $464 million discount as of December 31, 2016 and 2015, respectively, related to the difference between the fair value and the principal amount of the assumed MarkWest debt.

The following table shows five years of scheduled debt payments.

(In millions)	
2017	$ 1
2018	1
2019	251
2020	5
2021	—

Credit Agreements

On November 20, 2014, MPLX LP entered into a credit agreement with a syndicate of lenders ("MPLX Credit Agreement") which provided for a five-year, $1 billion bank revolving credit facility and a $250 million term loan facility. In connection with the closing of the MarkWest Merger, the Partnership amended the MPLX Credit Agreement to, among other things, increase the aggregate amount of revolving credit capacity under the credit agreement by $1 billion, for total aggregate commitments of $2 billion, and to extend the maturity for the bank revolving credit facility to December 4, 2020. The term loan facility was not amended and matures on November 20, 2019. Also in connection with the closing of the MarkWest Merger, MarkWest's bank revolving credit facility was terminated and the approximately $943 million outstanding under MarkWest's bank revolving credit facility was repaid with $850 million of borrowings under MPLX LP's bank revolving credit facility and $93 million of cash.

The bank revolving credit facility includes a letter of credit issuing capacity of up to $250 million and swingline capacity of up to $100 million. The borrowing capacity under the MPLX Credit Agreement may be increased by up to an additional $500 million, subject to certain conditions, including the consent of lenders whose commitments would increase. In addition, the maturity date may be extended from time-to-time during its term to a date that is one year after the then-effective maturity subject to the approval of lenders holding the majority of the commitments then outstanding, provided that the commitments of any non-consenting lenders will be terminated on the then-effective maturity date.

The term loan facility was drawn in full on November 20, 2014. The maturity date for the term loan facility may be extended for up to two additional one-year periods subject to the consent of the lenders holding a majority of the outstanding term loan borrowings, provided that the portion of the term loan borrowings held by any non-consenting lenders will continue to be due and payable on the then-effective maturity date. The borrowings under this facility during 2016 were at an average interest rate of 1.954 percent.

Borrowings under the MPLX Credit Agreement bear interest at either the Adjusted LIBOR or the Alternate Base Rate (as defined in the MPLX Credit Agreement), at our election, plus a specified margin. The Partnership is charged various fees and expenses in connection with the agreement, including administrative agent fees, commitment fees on the unused portion of the bank revolving credit facility and fees with respect to issued and outstanding letters of credit. The applicable margins to the benchmark interest rates and certain fees fluctuate based on the credit ratings in effect from time to time on the Partnership's long-term debt.

The MPLX Credit Agreement includes certain representations and warranties, affirmative and restrictive covenants and events of default that the Partnership considers to be usual and customary for an agreement of this type. This agreement includes a financial covenant that requires the Partnership to maintain a ratio of Consolidated Total Debt as of the end of each fiscal quarter to Consolidated EBITDA (both as defined in the MPLX Credit Agreement) for the prior four fiscal quarters of no greater than 5.0 to 1.0 (or 5.5 to 1.0 for up to two fiscal quarters following certain acquisitions.) Consolidated EBITDA is subject to adjustments for certain acquisitions completed and capital projects undertaken during the relevant period. Other covenants restrict the Partnership and certain of its subsidiaries from incurring debt, creating liens on its assets and entering into transactions with affiliates. As of December 31, 2016, the Partnership was in compliance with the covenants contained in the MPLX Credit Agreement.

During 2016, the Partnership borrowed $434 million under the bank revolving credit facility, at an average interest rate of 1.899 percent, per annum, and repaid $1.3 billion under the bank revolving credit facility. At December 31, 2016, the Partnership had no borrowings against the facility and $3 million letters of credit outstanding under this facility, resulting in total availability of $2 billion, or 99.9 percent of the borrowing capacity.

During 2015, the Partnership borrowed $992 million under the bank revolving credit facility, at an average interest rate of 1.617 percent, per annum, and repaid $500 million of these borrowings. At December 31, 2015, the Partnership had $877 million of borrowings and $8 million letters of credit outstanding under this facility, resulting in total unused loan availability of $1.12 billion, or 55.8 percent of the borrowing capacity.

During 2014, in connection with entering into the above mentioned MPLX Credit Agreement, the Partnership terminated its previously existing $500 million five-year MPLX Operations bank revolving credit agreement, dated as of September 14, 2012. However, during 2014, we borrowed $280 million under the previously existing agreement, at an average interest rate of 1.535 percent, per annum, and repaid all of these borrowings.

Senior Notes

In connection with the MarkWest Merger, MPLX LP assumed MarkWest's outstanding debt, which included $4.1 billion aggregate principal amount of senior notes. On December 22, 2015, approximately $4.04 billion aggregate principal amount of MarkWest's outstanding senior notes were exchanged for an aggregate principal amount of approximately $4.04 billion of new unsecured senior notes issued by MPLX LP in an exchange offer and consent solicitation undertaken by MPLX LP and MarkWest, leaving approximately $63 million aggregate principal of outstanding senior notes held by MarkWest.

The MPLX LP senior notes consist of (i) approximately $710 million aggregate principal amount of 5.500 percent senior notes due February 15, 2023, (ii) approximately $989 million aggregate principal amount of 4.500 percent senior notes due July 15, 2023, (iii) approximately $1.15 billion aggregate principal amount of 4.875 percent senior notes due December 1, 2024, (iv) approximately $500 million aggregate principal amount of four percent unsecured senior notes due February 15, 2025, and (v) approximately $1.19 billion aggregate principal amount of 4.875 percent senior notes due June 1, 2025. Interest on each series of MPLX LP senior notes is payable semi-annually in arrears according to the table below.

Senior Notes	Interest payable semi-annually in arrears
5.500% senior notes due 2023	February 15th and August 15th
4.500% senior notes due 2023	January 15th and July 15th
4.875% senior notes due 2024	June 1st and December 1st
4.000% senior notes due 2025	February 15th and August 15th
4.875% senior notes due 2025	June 1st and December 1st

After giving effect to the exchange offer and consent solicitation referred to above, as of December 31, 2016, MarkWest had outstanding (i) approximately $40 million aggregate principal amount of 5.500 percent senior notes due February 15, 2023, (ii) approximately $11 million aggregate principal amount of 4.500 percent senior notes due July 15, 2023, (iii) approximately $1 million aggregate principal amount of 4.875 percent senior notes due December 1, 2024 and (iv) approximately $11 million aggregate principal amount of 4.875 percent senior notes due June 1, 2025. Interest on each series of the MarkWest senior notes is payable semi-annually in arrears consistent with the table above.

On February 12, 2015, the Partnership completed a public offering of $500 million aggregate principal amount of four percent unsecured senior notes due February 15, 2025 (the “Feb 2025 Notes”). The net proceeds from the offering of the Feb 2025 Notes were approximately $495 million, after deducting underwriting discounts. The net proceeds were used to repay the amounts outstanding under its bank revolving credit facility, as well as for general partnership purposes. Interest is payable semi-annually in arrears, commencing on August 15, 2015.

SMR Transaction

On September 1, 2009, MarkWest completed the sale of the SMR (the “SMR Transaction”). At that time, MarkWest had begun constructing the SMR at its Javelina gas processing and fractionation complex in Corpus Christi, Texas. Under the terms of the agreement, MarkWest received proceeds of $73 million and the purchaser completed the construction of the SMR. MarkWest and the purchaser also executed a related product supply agreement under which the Partnership will receive the entire product produced by the SMR through 2030 in exchange for processing fees and the reimbursement of certain other expenses. The processing fee payments began when the SMR commenced operations in March 2010. MarkWest was deemed to have continuing involvement with the SMR as a result of certain provisions in the related agreements. Therefore, the transaction is treated as a financing arrangement under GAAP. The Partnership imputes interest on the SMR liability at 6.39 percent annually, its incremental borrowing rate at the time of the purchase accounting valuation. Each processing fee payment has multiple elements: reduction of principal of the SMR liability, interest expense associated with the SMR liability and facility expense related to the operation of the SMR. As part of purchase accounting, the SMR Transaction has been recorded at fair value. As of December 31, 2016 and 2015, the following amounts related to the SMR are included in the accompanying Consolidated Balance Sheets:

(In millions)	December 31, 2016	December 31, 2015
Assets		
Property, plant and equipment, net of accumulated depreciation	$61	$69
Liabilities		
Accrued liabilities	5	4
Deferred credits and other liabilities	91	96

18. Goodwill and Intangibles

Goodwill

The Partnership annually evaluates goodwill for impairment as of November 30, as well as whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit with goodwill is less than its carrying amount. The Partnership has performed its annual impairment tests, and no additional impairments in the carrying value of goodwill were identified in the periods presented.

During the first quarter of 2016, the Partnership determined that an interim impairment analysis of the goodwill recorded in connection with the MarkWest Merger was necessary based on consideration of a number of first quarter events and circumstances, including i) continued deterioration of near term commodity prices as well as longer term pricing trends, ii) recent guidance on reductions to forecasted capital spending, the slowing of drilling activity and the resulting reduced production growth forecasts released or communicated by the Partnership's producer customers and iii) increases in cost of capital. The combination of these factors was considered to be a triggering event requiring an interim impairment test. Based on the first step of the interim goodwill impairment analysis, the fair value for the three reporting units to which goodwill was assigned in connection with the MarkWest Merger was less than the respective carrying value. In step two of the impairment analysis, the implied fair values of the goodwill were compared to the carrying values within those reporting units. Based on this assessment, it was determined that goodwill was impaired in two of the three reporting units. Accordingly, the Partnership recorded an impairment charge of approximately $129 million in the first quarter of 2016. In the second quarter of 2016, the Partnership completed its purchase price allocation, which resulted in an additional $1 million of impairment expense that would have been recorded in the first quarter of 2016 had the purchase price allocation been completed as of that date. This adjustment to the impairment expense was the result of completing an evaluation of the deferred tax liabilities associated with the MarkWest Merger and their impact on the resulting goodwill that was recognized.

The fair value of the reporting units for the interim goodwill impairment analysis was determined based on applying the discounted cash flow method, which is an income approach, and the guideline public company method, which is a market approach. The discounted cash flow fair value estimate is based on known or knowable information at the interim measurement date. The significant assumptions that were used to develop the estimates of the fair values under the discounted cash flow method included management's best estimates of the expected future results and discount rates, which range from 10.5 percent to 11.5 percent. The fair value of the intangibles was determined based on applying the multi-period excess earnings method, which is an income approach. Key assumptions included attrition rates by reporting unit ranging from 5.0 percent to 10.0 percent and discount rates by reporting unit ranging from 11.5 percent to 12.8 percent. Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of the interim goodwill impairment test will prove to be an accurate prediction of the future. The fair value measurements for the individual reporting units' overall fair values, and the fair values of the goodwill assigned thereto, represent Level 3 measurements.

The changes in carrying amount of goodwill were as follows for the periods presented:

(In millions)	L&S	G&P	Total
Gross goodwill as of December 31, 2014	$116	$ —	$ 116
Accumulated impairment losses	—	—	—
Balance as of December 31, 2014	116	—	116
Acquisitions	—	2,454	2,454
Gross goodwill as of December 31, 2015	116	2,454	2,570
Accumulated impairment losses	—	—	—
Balance as of December 31, 2015	116	2,454	2,570
Purchase price allocation adjustments[1]	—	(241)	(241)
Impairment losses	—	(130)	(130)
Balance as of December 31, 2016	$116	$2,083	$2,199
Gross goodwill as of December 31, 2016	$116	$2,213	$2,329
Accumulated impairment losses	—	(130)	(130)
Balance as of December 31, 2016	$116	$2,083	$2,199

(1) See Note 4 for further discussion on purchase price allocation adjustments.

Intangible Assets

The Partnership's intangible assets as of December 31, 2016 and 2015 are comprised of customer contracts and relationships, as follows:

	December 31, 2016			December 31, 2015			
(In millions)	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net	Useful Life
L&S	$—	$—	$—	$—	$ —	$ —	N/A
G&P	533	(41)	492	468	(2)	466	11-25 years
	$ 533	$ (41)	$ 492	$ 468	$ (2)	$ 466	

Estimated future amortization expense related to the intangible assets at December 31, 2016 is as follows:

(In millions)	
2017	$ 38
2018	38
2019	38
2020	38
2021	38
Thereafter	302
Total	$492

19. Supplemental Cash Flow Information

(In millions)	2016	2015	2014
Net cash provided by operating activities included:			
Interest paid (net of amounts capitalized)	$ 212	$ 13	$ 3
Income taxes paid	3	—	—
Non-cash investing and financing activities:			
Net transfers of property, plant and equipment from materials and supplies inventories	$ 4	$ 5	$ 1
Contribution—common units issued[1]	669	—	200
Acquisition:			
Fair value of MPLX LP units issued[1]	—	7,326	—
Payable to seller	—	50	—

(1) See Note 4.

The Consolidated Statements of Cash Flows exclude changes to the Consolidated Balance Sheets that did not affect cash. The following is the change of additions to property, plant and equipment related to capital accruals:

(In millions)	2016	2015	2014
(Decrease) increase in capital accruals	$ (25)	$ 26	$ 11

In connection with the acquisition of HSM described in Note 4, MPC agreed to waive first quarter 2016 distributions on the MPLX LP common units issued in connection with the transaction. MPC did not receive general partner distributions or incentive distribution rights that would have otherwise accrued on such MPLX LP common units with respect to the first quarter distributions. The value of these waived distributions was $15 million.

20. Equity-based Compensation Plan

Description of the Plan

The MPLX LP 2012 Incentive Compensation Plan ("MPLX 2012 Plan") authorizes the MPLX GP board of directors (the "Board") to grant unit options, unit appreciation rights, restricted units and phantom units, distribution equivalent rights, unit awards, profits interest units, performance units and other unit-based awards to the Partnership's or any of its affiliates' employees, officers and directors, including directors and officers of MPC. No more than 2.75 million MPLX LP common limited partner units may be delivered under the MPLX 2012 Plan. Units delivered pursuant to an award granted under the MPLX 2012 Plan may be funded through acquisition on the open market, from the Partnership or from an affiliate of the Partnership, as determined by the Board.

Unit-based awards under the Plan

The Partnership expenses all unit-based payments to employees and non-employee directors based on the grant date fair value of the awards over the requisite service period, adjusted for estimated forfeitures.

Phantom Units—The Partnership grants phantom units under the MPLX 2012 Plan to non-employee directors of MPLX LP's general partner and of MPC. Awards to non-employee directors are accounted for as non-employee awards. Phantom units granted to non-employee directors vest immediately at the time of the grant, as they are non-forfeitable, but are not issued until the director's departure from the board of directors. Prior to issuance, non-employee directors do not have the right to vote such units and cash distribution equivalents accrue in the form of additional phantom units and will be issued when the director departs from the board of directors.

The Partnership grants phantom units under the MPLX 2012 Plan to certain officers and non-officers of MPLX LP, MPLX LP's general partner and MPC who make significant contributions to our business. These grants are accounted for as employee awards. In general, these phantom units will vest over a requisite service period of up to three years. Prior to vesting, these phantom unit recipients will not have the right to vote such units and cash distributions declared will be accrued and paid upon vesting. The accrued distributions at December 31, 2016 and 2015 were $2 million and less than $1 million, respectively.

The fair values of phantom units are based on the fair value of MPLX LP common limited partner units on the grant date.

Performance Units—The Partnership grants performance units under the MPLX 2012 Plan to certain officers of MPLX LP's general partner and certain eligible MPC officers who make significant contributions to its business. These awards are intended to have a per unit payout determined by the total unitholder return of MPLX LP common units as compared to the total unitholder return of a selected group of peer partnerships. The final per-unit payout will be the average of the results of four measurement periods during the 36 month requisite service period. These performance units will pay out 75 percent in cash and 25 percent in MPLX LP common units. The performance units paying out in cash are accounted for as liability awards and recorded at fair value with a mark-to-market adjustment made each quarter. The performance units paying out in units are accounted for as equity awards and have a weighted average grant date fair value of $0.63 per unit for 2016 and $1.03 per unit for 2015, as calculated using a Monte Carlo valuation model.

Outstanding Phantom Unit Awards

The following is a summary of phantom unit award activity of MPLX LP common limited partner units in 2016:

	Phantom Units		
	Number of Units	Weighted Average Fair Value	Aggregate Intrinsic Value (In millions)
Outstanding at December 31, 2015	1,031,219	$35.49	
Granted	458,727	29.42	
Settled	(166,576)	38.12	
Forfeited	(149,959)	32.72	
Outstanding at December 31, 2016	1,173,411	33.09	
Vested and expected to vest at December 31, 2016	1,157,676	33.12	$40
Convertible at December 31, 2016	494,189	34.11	$17

The 494,189 convertible units are held by our non-employee directors and certain officers. These units are non-forfeitable and issuable upon the holder's departure from service to the company.

The following is a summary of the values related to phantom units held by officers and non-employee directors:

	Phantom Units	
	Intrinsic Value of Units Issued During the Period (in millions)	Weighted Average Grant Date Fair Value of Units Granted During the Period
2016	$5	$29.42
2015	3	35.00
2014	1	49.56

As of December 31, 2016, unrecognized compensation cost related to phantom unit awards was $17 million, which is expected to be recognized over a weighted average period of 2.0 years.

Outstanding Performance Unit Awards

The following is a summary of activity of performance unit awards paying out in MPLX LP common limited partner units in 2016:

	Performance Units	
	Number of Units	Weighted Average Fair Value
Outstanding at December 31, 2015	1,521,392	$1.00
Granted	789,375	0.63
Settled	(458,011)	0.79
Forfeited	(53,507)	1.06
Outstanding at December 31, 2016	1,799,249	0.89

As of December 31, 2016, unrecognized compensation cost related to equity-classified performance unit awards was $1 million, which is expected to be recognized over a weighted average period of 1.6 years.

Performance units paying out in units have a grant date fair value calculated using a Monte Carlo valuation model, which requires the input of subjective assumptions. The following table provides a summary of the weighted average inputs used for these assumptions:

	2016	2015	2014
Risk-free interest rate	0.96%	0.95%	0.63%
Look-back period	2.83 years	2.84 years	2.84 years
Expected volatility	47.59%	30.12%	17.17%
Grant date fair value of performance units granted	$ 0.63	$ 1.03	$ 1.16

The assumption for expected volatility of our unit price reflects the historical volatility of MPLX LP common units. The look-back period reflects the remaining performance period at the grant date. The risk-free interest rate for the remaining performance period as of the grant date is based on the U.S. Treasury yield curve in effect at the time of the grant.

Total Unit-Based Compensation Expense

Total unit-based compensation expense for awards settling in MPLX LP common units was $10 million in 2016, $4 million in 2015 and $3 million in 2014. Approximately $15 million was charged to the MarkWest purchase price in 2015 for MPLX LP unit-based compensation awards granted in connection with the MarkWest Merger.

MPC's Stock-based Compensation

Stock-based compensation expenses charged to MPLX LP under our employee services agreement with MPC were $5 million for 2016 and $1 million for 2015 and 2014, respectively.

21. Lease Operations

Based on the terms of certain natural gas gathering, transportation and processing agreements, the Partnership is considered to be the lessor under several implicit operating lease arrangements in accordance with GAAP. The Partnership's primary implicit lease operations relate to a natural gas gathering agreement in the Marcellus Shale for which it earns a fixed-fee for providing gathering services to a single producer using a dedicated gathering system. As the gathering system is expanded, the fixed-fee charged to the producer is adjusted to include the additional gathering assets in the lease. The primary term of the natural gas gathering arrangement expires in 2023 and will continue thereafter on a year to year basis until terminated by either party. Other significant implicit leases relate to a natural gas processing agreement in the Marcellus Shale and a natural gas processing agreement in the Southern Appalachia region for which the Partnership earns minimum monthly fees for providing processing services to a single producer using a dedicated processing plant. The primary term of these natural gas processing agreements expire during 2023 and 2030.

Based on the terms of the Partnership's fee-based transportation services agreement with MPC, HSM is also considered to be a lessor of its marine equipment in accordance with GAAP. The Partnership's revenue from its implicit lease arrangements, excluding executory costs, totaled approximately $464 million in 2016, $89 million in 2015 and $14 million in 2014.

The Partnership's implicit lease arrangements related to the processing facilities contain contingent rental provisions whereby the Partnership receives additional fees if the producer customer exceeds the monthly minimum processed volumes. During the years ended December 31, 2016 and 2015, the Partnership received $7 million and less than $1 million, respectively, in contingent lease payments.

The following is a schedule of minimum future rentals on the non-cancellable operating leases as of December 31, 2016:

(In millions)	Intercompany	Third Party	Total
2017	$101	$ 197	$ 298
2018	101	200	301
2019	101	202	303
2020	101	201	302
2021	—	185	185
2022 and thereafter	—	460	460
Total minimum future rentals	$404	$1,445	$1,849

The following schedule summarizes the Partnership's investment in assets held for operating lease by major classes as of December 31, 2016 and 2015:

	December 31,	
(In millions)	2016	2015
Natural gas gathering and NGL transportation pipelines and facilities	$ 650	$ 619
Natural gas processing facilities	844	753
Barges	388	360
Towing vessels	91	91
Construction in progress	219	110
Property, plant and equipment	2,192	1,933
Less: accumulated depreciation	(266)	(170)
Total property, plant and equipment	$1,926	$1,763

22. Asset Retirement Obligations

The Partnership's assets subject to AROs are primarily certain gas-gathering pipelines and processing facilities, a crude oil pipeline and other related pipeline assets. The Partnership also has land leases that require the Partnership to return the land to its original condition upon termination of the lease. The Partnership reviews current laws and regulations governing obligations for asset retirements and leases, as well as the Partnership's leases and other agreements.

The following is a reconciliation of the changes in the ARO from January 1, 2015 to December 31, 2016:

(In millions)	2016	2015
ARO at beginning of period	$ 17	$—
Liabilities assumed in conjunction with the MarkWest Merger	—	15
Liabilities incurred	8	2
Adjustments to AROs	(1)	—
Accretion expense	1	—
ARO at end of period	$ 25	$ 17

At December 31, 2016 and 2015, there were no assets legally restricted for purposes of settling AROs. The AROs have been recorded as part of *Deferred credits and other liabilities* in the accompanying Consolidated Balance Sheets.

In addition to recorded AROs, the Partnership has other AROs related to certain gathering, processing and other assets as a result of environmental and other legal requirements. The Partnership is not required to perform such work until it permanently ceases operations of the respective assets. Because the Partnership considers the operational life of these assets to be indeterminable, an associated ARO cannot be estimated and is not recorded.

23. Commitments and Contingencies

The Partnership is the subject of, or a party to, a number of pending or threatened legal actions, contingencies and commitments involving a variety of matters, including laws and regulations relating to the environment. Some of these matters are discussed below. For matters for which the Partnership has not recorded an accrued liability, the Partnership is unable to estimate a range of possible losses for the reasons discussed in more detail below. However, the ultimate resolution of some of these contingencies could, individually or in the aggregate, be material.

Environmental Matters—The Partnership is subject to federal, state and local laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for non-compliance.

At December 31, 2016 and 2015, accrued liabilities for remediation totaled $1 million and $1 million, respectively. However, it is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties, if any, which may be imposed. At December 31, 2016 and 2015, there was less than $1 million, respectively, in receivables from MPC for indemnification of environmental costs related to incidents occurring prior to the Initial Offering.

In July 2015, representatives from the EPA and the United States Department of Justice conducted a raid on a MarkWest Liberty Midstream pipeline launcher/receiver site utilized for pipeline maintenance operations in Washington County, Pennsylvania pursuant to a search warrant issued by a magistrate of the United States District Court for the Western District of Pennsylvania. As part of this initiative, the U.S. Attorney's Office for the Western District of Pennsylvania, proceeded with an investigation of MarkWest Liberty Midstream's launcher/receiver, pipeline and compressor station operations. In response to the investigation, MarkWest initiated independent studies which demonstrated that there was no risk to worker safety and no threat of public harm associated with MarkWest Liberty Midstream's launcher/receiver operations. These findings were supported by a subsequent inspection and review by the Occupational Safety and Health Administration. After providing these studies, and other substantial documentation related to MarkWest Liberty Midstream's pipeline and compressor stations, and arranging site visits and conducting several meetings with the government's representatives, on September 13, 2016, the U.S. Attorney's Office for the Western District of Pennsylvania rendered a declination decision, dropping its criminal investigation and declining to pursue charges in this matter.

MarkWest Liberty Midstream continues to discuss with the EPA and the State of Pennsylvania civil enforcement allegations associated with permitting or other related regulatory obligations for its launcher/receiver and compressor station facilities in the region. In connection with these discussions, MarkWest Liberty Midstream received an initial proposal from the EPA to settle all civil claims associated with this matter for the combination of a proposed cash penalty of approximately $2.4 million and proposed supplemental environmental projects with an estimated cost of approximately $3.6 million. MarkWest Liberty Midstream will be submitting a response asserting that this action involves novel issues surrounding primarily minor source emissions from facilities that the agencies themselves considered de minimis were not the subject of regulation and consequently that the settlement proposal is excessive. MarkWest will continue to negotiate with EPA regarding the amount and scope of the proposed settlement.

The Partnership is involved in a number of other environmental enforcement matters arising in the ordinary course of business. While the outcome and impact on MPLX LP cannot be predicted with certainty, management believes the resolution of these environmental matters will not, individually or collectively, have a material adverse effect on its consolidated results of operations, financial position or cash flows.

Other Lawsuits—In 2003, the State of Illinois brought an action against the Premcor Refining Group, Inc. ("Premcor") and Apex Refining Company ("Apex") asserting claims for environmental cleanup related to the refinery owned by these entities in the Hartford/Wood River, Illinois area. In 2006, Premcor and Apex filed third-party complaints against numerous owners and operators of petroleum products facilities in the Hartford/Wood River, Illinois area, including MPL. These complaints, which have been amended since filing, assert claims of common law nuisance and contribution under the Illinois Contribution Act and other laws for environmental cleanup costs that may be imposed on Premcor and Apex by the State of Illinois. On September 6, 2016, the trial court approved a settlement between Apex and the State of Illinois whereby Apex agreed to settle all claims against it for a $10 million payment. Premcor has objected to this ruling and is seeking an appeal. There are several third-party defendants in the litigation and MPL has asserted cross-claims in contribution against the various third-party defendants. This litigation is currently pending in the Third Judicial Circuit Court, Madison County, Illinois. While the ultimate outcome of these litigated matters remains uncertain, neither the likelihood of an unfavorable outcome nor the ultimate liability, if any, with respect to this matter can be determined at this time and the Partnership is unable to estimate a reasonably possible loss (or range of loss) for this litigation. Under the omnibus agreement, MPC will indemnify the Partnership for the full cost of any losses should MPL be deemed responsible for any damages in this lawsuit. The Partnership is also a party to a number of other lawsuits and other proceedings arising in the ordinary course of business. While the ultimate outcome and impact to the Partnership cannot be predicted with certainty, the Partnership believes the resolution of these other lawsuits and proceedings will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Guarantees—Over the years, the Partnership has sold various assets in the normal course of its business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require the Partnership to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. The Partnership is typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

Contractual Commitments and Contingencies—At December 31, 2016 the Partnership's contractual commitments to acquire property, plant and equipment totaled $588 million. In addition, from time to time and in the ordinary course of business, the Partnership and its affiliates provide guarantees of the Partnership's subsidiaries payment and performance obligations in the G&P segment. Our contractual commitments at

December 31, 2016 were primarily related to plant expansion projects for the Marcellus and Southwest Operations and the Cornerstone Pipeline project. Certain natural gas processing and gathering arrangements require the Partnership to construct new natural gas processing plants, natural gas gathering pipelines and NGL pipelines and contain certain fees and charges if specified construction milestones are not achieved for reasons other than force majeure. In certain cases, certain producers may have the right to cancel the processing arrangements if there are significant delays that are not due to force majeure. As of December 31, 2016, management does not believe there are any indications that the Partnership will not be able to meet the construction milestones, that force majeure does not apply, or that such fees and charges will otherwise be triggered.

Lease and Other Contractual Obligations—The Partnership executed transportation and terminalling agreements that obligate us to minimum volume, throughput or payment commitments over the terms of the agreements, which range from three to ten years. After the minimum volume commitments are met in the transportation and terminalling agreements, the Partnership pays additional amounts based on throughput. There are escalation clauses in the transportation and terminalling agreements, which are based on CPI adjustments. The minimum future payments under these agreements as of December 31, 2016 are as follows:

(In millions)	
2017	$ 46
2018	62
2019	61
2020	61
2021	61
2022 and thereafter	317
Total	$608

The Partnership has various non-cancellable operating lease agreements and a long-term propane storage agreement expiring at various times through fiscal year 2040. Most of these leases include renewal options. The Partnership also leases certain pipelines under a capital lease that has a fixed price purchase option in 2020. Future minimum commitments as of December 31, 2016, for capital lease obligations and for operating lease obligations having initial or remaining non-cancellable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2017	$ 1	$ 61
2018	1	51
2019	2	42
2020	5	37
2021	—	36
Later years	—	76
Total minimum lease payments	9	$303
Less: imputed interest costs	1	
Present value of net minimum lease payments	$ 8	

Operating lease rental expense was:

(In millions)	2016	2015	2014
Minimum rental expense	$57	$21	$ 17

SMR Transaction—On September 1, 2009, MarkWest entered into a product supply agreement creating a long-term contractual obligation for the payment of processing fees in exchange for the entire product processed by the SMR. See Note 17 for additional discussion. The product received under this agreement is sold to a refinery customer pursuant to a corresponding long-term agreement. The minimum amounts payable annually under the product supply agreement, excluding the potential impact of inflation adjustments per the agreement, are as follows:

(In millions)	
2017	$ 17
2018	17
2019	17
2020	17
2021	17
2022 and thereafter	143
Total minimum payments	228
Less: Services element	87
Less: Interest	45
Total SMR liability	96
Less: Current portion of SMR liability	5
Long-term portion of SMR liability	$ 91

24. Subsequent Event

On February 6, 2017, MarkWest Liberty Midstream executed definitive agreements with Antero Midstream LLC, and affiliate of Antero Midstream LP ("Antero Midstream") for the formation of a joint venture, Sherwood Midstream LLC ("Sherwood Midstream"), to process natural gas at the Sherwood Complex and fractionate natural gas liquids at the Hopedale Complex. Sherwood Midstream is owned 50 percent by Antero Midstream and 50 percent by MarkWest Liberty Midstream. These transactions were effective as of January 1, 2017. In connection with these transactions, MarkWest Liberty Midstream contributed approximately $134 million of assets to Sherwood Midstream, comprised of the three 200 mmcf/d gas processing plants under construction at the Sherwood Complex. MarkWest Liberty Midstream will operate Sherwood Midstream's gas processing facilities and will also retain sole and exclusive ownership and operation of the existing six 200 mmcf/d gas processing plants at the Sherwood Complex. In addition, MarkWest Liberty Midstream and Sherwood Midstream entered into a joint venture, Sherwood Midstream Holdings LLC ("Sherwood Midstream Holdings"), to own certain infrastructure at the Sherwood Complex that is shared by and supports the operation of both the Sherwood Midstream and MarkWest Liberty Midstream gas processing plants. MarkWest Liberty Midstream contributed approximately $207 million of assets to Sherwood Midstream Holdings, and as of February 6, 2017, MarkWest Liberty Midstream owned a 79 percent ownership interest in Sherwood Midstream Holdings, and the remaining 21 percent ownership interest was owned by Sherwood Midstream. Sherwood Midstream also purchased an interest in 20 mbpd of existing propane and heavier NGL fractionation capacity owned by MarkWest Ohio Fractionation Company, L.L.C. ("Ohio Fractionation"), a subsidiary of MarkWest Liberty Midstream, at the Hopedale Complex for $125 million. Sherwood Midstream will also have the option to purchase an interest in future fractionation train expansions at the Hopedale Complex, subject to the production of incremental NGLs from Sherwood Midstream's processing facilities. Ohio Fractionation and MarkWest Utica EMG will continue to own and operate the remaining portion of the Hopedale Complex, including all rail and marketing infrastructure, as well as the NGL pipelines connecting MarkWest Liberty Midstream's and MarkWest Utica EMG's gas processing plants to the Hopedale Complex. In connection with the foregoing transactions, Antero Midstream made an initial capital contribution to Sherwood Midstream of approximately $154 million, and it is expected that MarkWest Liberty Midstream and Antero Midstream will each contribute 50 percent of capital needed to fund Sherwood Midstream's operations.

On February 10, 2017, the Partnership completed a public offering of $1.25 billion aggregate principal amount of 4.125 percent unsecured senior notes due March 2027 (the "2027 Senior Notes") and $1.0 billion aggregate principal amount of 5.200 percent unsecured senior notes due March 2047 (the "2047 Senior Notes" and, collectively with the 2027 Senior Notes, the "New Senior Notes"). The 2027 Senior Notes and the 2047 Senior Notes were offered at a price to the public of 99.834 percent and 99.304 percent of par, respectively, at an interest rate of 4.125 percent and 5.200 percent, respectively. The Partnership intends to use the net proceeds from this offering for general partnership purposes, which may include, from time to time, acquisitions (including the previously announced planned dropdown of assets from MPC, the acquisition of the Ozark pipeline, and the acquisition of a partial, indirect equity interest in the Bakken Pipeline system) and capital expenditures.

On February 13, 2017, the Partnership announced that it has entered into an asset purchase agreement with Enbridge Pipelines (Ozark) LLC ("Enbridge Ozark"), under which an affiliate of Pipe Line Holdings has agreed to purchase Ozark pipeline for approximately $220 million from Enbridge Ozark. The Ozark pipeline is a 433-mile, 22-inch crude oil pipeline originating in Cushing, Oklahoma, and terminating in Wood River, Illinois, and capable of transporting approximately 230,000 barrels per day. This purchase transaction is expected to close in the first quarter of 2017.

On February 15, 2017, MPLX LP closed on its previously announced intent to participate in a joint venture with Enbridge Energy Partners L.P. ("Enbridge Energy Partners") to acquire a 9.1875 percent indirect interest in the Dakota Access Pipeline ("DAPL") and Energy Transfer Crude Oil Company Pipeline ("ETCOP") projects, collectively referred to as the Bakken Pipeline system, from Energy Transfer Partners, L.P. ("ETP") and Sunoco Logistics Partners, L.P. ("SXL") for $500 million.

The Bakken Pipeline system is currently expected to deliver in excess of 470,000 barrels per day of crude oil from the Bakken/ Three Forks production area in North Dakota to the Midwest through Patoka, Illinois and ultimately to the Gulf Coast. ETP and SXL collectively own a 75 percent interest in each of the two joint ventures that are developing the Bakken Pipeline system. MPLX LP and Enbridge Energy Partners intend to form a new joint venture to acquire 49 percent of ETP and SXL's 75 percent indirect interest in the Bakken Pipeline system. MPLX LP will own 25 percent of this new joint venture with Enbridge, which results in its 9.1875 percent indirect ownership interest in the Bakken Pipeline system. MPLX LP expects to account for its investment using the equity method of accounting.

Select Quarterly Financial Data (Unaudited)

(In millions, except per unit data)	2016[3] 1st Qtr.[1]	2016[3] 2nd Qtr.[2]	2016[3] 3rd Qtr.	2016[3] 4th Qtr.	2015 1st Qtr.	2015 2nd Qtr.	2015 3rd Qtr.	2015 4th Qtr.[3]
Total revenues and other income	$ 609	$ 564	$ 703	$ 714	$ 201	$ 213	$ 214	$ 333
Income from operations	27	76	207	197	74	82	68	74
Net (loss) income	(37)	20	143	132	68	76	63	42
Net (loss) income attributable to MPLX LP	(60)	19	141	133	46	51	41	18
Net (loss) income attributable to MPLX LP per limited partner unit:								
Common—basic	$ (0.33)	$ (0.11)	$ 0.22	$ 0.17	$ 0.46	$ 0.50	$ 0.41	$ (0.14)
Common—diluted	(0.33)	(0.11)	0.21	0.17	0.46	0.50	0.41	(0.14)
Subordinated—basic and diluted	—	—	—	—	0.46	0.50	—	—
Cash distributions declared per limited partner common unit	$0.5050	$0.5100	$0.5150	$0.5200	$0.4100	$0.4400	$0.4700	$0.5000
Distributions declared:								
Limited partner units—Public	$ 127	$ 131	$ 135	$ 140	$ 10	$ 10	$ 11	$ 120
Limited partner units—MPC	29	41	44	45	23	25	27	29
General partner units—MPC	4	4	5	5	1	1	1	3
Incentive distribution rights—MPC	40	46	49	52	3	6	8	37
Redeemable preferred units	—	9	16	16	—	—	—	—
Total distributions declared	$ 200	$ 231	$ 249	$ 258	$ 37	$ 42	$ 47	$ 189

(1) First quarter 2016 results included goodwill impairment expense of $129 million. See Note 18 for more information.

(2) Second quarter 2016 results included impairment expense related to equity method investments of $89 million. See Note 5 for more information.

(3) These amounts include results from the MarkWest Merger which closed on December 4, 2015. See Note 4 for more information on the MarkWest Merger.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

None

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

The Partnership's management, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 Act, as amended, as of December 31, 2016. Based on this evaluation, the Partnership's management, including our Chief Executive Officer and Chief Financial Officer, concluded that as of December 31, 2016, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 Act, as amended, is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and to provide reasonable assurance that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

Internal Control Over Financial Reporting and Changes in Internal Control Over Financial Reporting

During the fourth quarter ended December 31, 2016, we completed the integration of MarkWest into our internal control environment. See Item 8. Financial Statements and Supplementary Data—Management's Report on Internal Control over Financial Reporting.

Limitations on Controls

Management has designed our disclosure controls and procedures and internal control over financial reporting to provide reasonable assurance of achieving their objectives as specified above. Management does not expect, however, that our disclosure controls and procedures or our internal control over financial reporting will prevent or detect all error and fraud. Any control system, no matter how well designed and operated, is based upon certain assumptions and can provide only reasonable, not absolute, assurance that its objectives will be met. Further, no evaluation of controls can provide absolute assurance that misstatements due to error or fraud will not occur or that management has detected all control issues and instances of fraud, if any, within the Partnership.

Item 9B. Other Information

On February 23, 2017, our general partner executed an amendment (the "First Amendment") to the Third Amended and Restated Agreement of Limited Partnership of MPLX LP, dated as of October 31, 2016 (the "Partnership Agreement"). The First Amendment includes, among other amendments, modifications to the Partnership Agreement associated with recently issued Treasury Regulations promulgated under Section 707 of the Internal Revenue Code of 1986, as amended.

The foregoing description of the First Amendment is summary in nature and subject to, and qualified in its entirety by, the full text of the First Amendment, a copy of which is attached as Exhibit 3.4 to this Annual Report on Form 10-K and is incorporated herein by reference.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

MANAGEMENT OF MPLX LP

We are managed by the directors and executive officers of our general partner, MPLX GP LLC. Our general partner is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. MPC indirectly owns all of the membership interests in our general partner. Our general partner has a board of directors, and our unitholders are not entitled to elect the directors or directly or indirectly to participate in our management or operations. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, we intend to incur indebtedness that is non-recourse to our general partner.

The board of directors of our general partner has twelve directors. MPC appoints all members to the board of directors of our general partner, which we may refer to as our board. Our board has determined that each of Michael L. Beatty, David A. Daberko, Christopher A. Helms, Garry L. Peiffer, Dan D. Sandman, John P. Surma and C. Richard Wilson meets the independence standards in our Governance Principles, has no material relationship with the Partnership other than that arising solely from the capacity as a director and, in addition, satisfies the independence requirements of the NYSE, including the NYSE independence standards applicable to the committees on which each such director serves. In making its determinations, our board considered that Mr. Helms serves on the board of directors of Range Resources Corporation. During 2016, Range Resources was a significant customer of MarkWest and MarkWest provided gathering, processing and NGL fractionation services to Range Resources. The relationship with Range Resources was entered into in the ordinary course of business on arms-length terms in amounts and under circumstances that did not affect Mr. Helms's independence under our Governance Principles or under applicable law and NYSE listing standards.

Neither we nor our subsidiaries have any employees. Our general partner has the sole responsibility for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our general partner, but we sometimes refer to these individuals as our employees for ease of reference.

Director Independence

Although most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a publicly traded limited partnership like us to have a majority of independent directors on our board or to establish a compensation or a nominating and corporate governance committee. We are, however, required to have an audit committee of at least three members, and all of our audit committee members are required to meet the independence and financial literacy tests established by the NYSE and the Exchange Act.

Committees of the Board of Directors

Our board has an audit committee and a conflicts committee, and may have such other committees as the board shall determine from time to time. The audit committee and the conflicts committee are comprised entirely of independent directors. Additionally, an executive committee of the board, comprised of Gary R. Heminger and Dan D. Sandman, has been established to address matters that may arise between meetings of the board. This executive committee may exercise the powers and authority of the board subject to specific limitations consistent with applicable law.

Each of the standing committees of the board of directors has the composition and responsibilities described below.

Audit Committee

C. Richard Wilson serves as the chairman, and Michael L. Beatty, Christopher A. Helms, Garry L. Peiffer and Dan D. Sandman are members, of our audit committee. Mr. Peiffer is the chair-elect of the audit committee and will assume the position of chairman effective March 1, 2017. Our audit committee assists the board of directors in its oversight of the integrity of our financial statements, and our compliance with legal and regulatory requirements and our disclosure controls and procedures. Our audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. Our audit committee also is responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to our audit committee.

Our audit committee has a written charter adopted by the board of directors of our general partner, which is available on our website at http://ir.mplx.com by selecting "Corporate Governance" and clicking on "Board Committees and Charters," "Audit Committee," "Audit Committee Charter." The audit committee charter requires our audit committee to assess and report to the board on the adequacy of the charter on an annual basis. Each of the members of our audit committee is independent as independence is defined in the Exchange Act, and also satisfies the general independence requirements of the NYSE.

Audit Committee Financial Expert

Based on the attributes, education and experience requirements set forth in the rules of the SEC, the board of directors of our general partner has determined that C. Richard Wilson, Christopher A. Helms and Garry L. Peiffer each qualify as an "Audit Committee Financial Expert."

Mr. Wilson served as the president of Buckeye Partners, L.P. and its general partner, Buckeye GP LLC, and also served as its chief operating officer, a director and its vice chairman. During the period he was chief operating officer, Mr. Wilson was responsible for all aspects of Buckeye Partners, L.P.'s operations and administration, including the oversight of accounting and audit functions, and legal and regulatory compliance.

Mr. Helms served in various capacities at NiSource Inc. and its affiliate, NiSource Gas Transmission and Storage, including as executive vice president and group chief executive officer and group president, Pipeline of NiSource Inc., where he was also a member of the executive council and corporate risk management committee. He also served as chief executive officer and executive director of NiSource Gas Transmission and Storage and has extensive experience in the areas of finance, accounting, compliance, strategic planning and risk oversight. Mr. Helms has served on the finance and audit committee of another public company.

Mr. Peiffer previously served as the assistant controller and controller of various MPC divisions and was senior vice president of Finance and Commercial Services of Marathon Ashland Petroleum LLC and its successors for more than a decade. During his various accounting and finance assignments while at MPC, Mr. Peiffer was responsible for preparing financial statements, supervising financial statement preparation, reviewing internal controls and attending audit committee meetings. Mr. Peiffer holds a bachelor's degree in accounting and passed the certified public accountant exam in Ohio.

Audit Committee Report

The Audit Committee has reviewed and discussed the Partnership's audited financial statements and its report on internal controls over financial reporting for 2016 with the management of MPLX GP LLC, the Partnership's general partner. The Audit Committee discussed with the independent auditors, PricewaterhouseCoopers LLP, the matters required to be discussed by the Public Company Accounting Oversight Board's standard, Auditing Standard No. 1301. The Committee has received the written disclosures and the letter from PricewaterhouseCoopers LLP required by the applicable requirements of the Public Company Accounting Oversight Board for independent auditor communications with audit committees concerning independence and has discussed with PricewaterhouseCoopers LLP its independence. Based on the review and discussions referred to above, the Audit Committee recommended to the Board that the audited financial statements and the report on internal controls over financial reporting for MPLX LP be included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2016, for filing with the SEC.

C. Richard Wilson, Chairman
Michael L. Beatty
Christopher A. Helms
Garry L. Peiffer
Dan D. Sandman

Conflicts Committee

Christopher A. Helms serves as the chairman, and Michael L. Beatty, Dan D. Sandman and C. Richard Wilson are members, of our conflicts committee. Our conflicts committee reviews specific matters that may involve conflicts of interest in accordance with the terms of our partnership agreement. Any matters approved by our conflicts committee in good faith will be deemed to be approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. The members of our conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. In addition, the members of our conflicts committee may not own any interest in our general partner or any interest in us, our subsidiaries or our affiliates other than common units or awards under our incentive compensation plan.

Our conflicts committee has a written charter adopted by the board of directors of our general partner, which is available on our website at http://ir.mplx.com by selecting "Corporate Governance" and clicking on "Board Committees and Charters," "Conflicts Committee," "Conflicts Committee Charter." The conflicts committee charter requires our conflicts committee to assess and report to the board on the adequacy of the charter on an annual basis. Each of the members of our conflicts committee is independent as independence is defined in the Exchange Act, and also satisfies the general independence requirements of the NYSE.

DIRECTORS AND EXECUTIVE OFFICERS OF MPLX GP LLC

Directors are elected by the sole member of our general partner and hold office until their successors have been elected or qualified or until their earlier death, resignation, removal or disqualification. Executive officers are appointed by, and serve at the discretion of, the board of directors. The following table shows information for the directors, and executive and corporate officers of MPLX GP LLC.

Name	Age as of January 31, 2017	Position with MPLX GP LLC
Gary R. Heminger	63	Chairman of the Board of Directors and Chief Executive Officer
Donald C. Templin	53	Director and President
Pamela K.M. Beall	60	Director, Executive Vice President and Chief Financial Officer
Michael L. Beatty	69	Director
David A. Daberko	71	Director
Timothy T. Griffith	47	Director
Christopher A. Helms	62	Director
Garry L. Peiffer	65	Director
Dan D. Sandman	68	Director
Frank M. Semple	65	Director
John P. Surma	62	Director
C. Richard Wilson	72	Director
C. Corwin Bromley	59	Executive Vice President and General Counsel (Chief Legal Officer)
Gregory S. Floerke	53	Executive Vice President and Chief Operating Officer, MarkWest Operations
Randy S. Nickerson	55	Executive Vice President and Chief Commercial Officer, MarkWest Assets
Paula L. Rosson	50	Senior Vice President and Chief Accounting Officer
Timothy J. Aydt[(1)]	53	Vice President, Operations
Molly R. Benson[(1)]	50	Vice President, Corporate Secretary and Chief Compliance Officer
Peter Gilgen[(1)]	60	Vice President and Treasurer
Frank A. Quintana[(1)]	43	Vice President, Tax
John S. Swearingen	57	Vice President, Crude Oil and Refined Products Pipelines

(1) Corporate officer.

Gary R. Heminger. Gary R. Heminger was appointed chief executive officer and elected chairman of the board of directors of our general partner in June 2012. He is also chairman of the board, president and chief executive officer of MPC, and a member of the board of directors of Fifth Third Bancorp. Mr. Heminger is past-chairman of the board of trustees of Tiffin University. He serves on the boards of directors and executive committees of the American Petroleum Institute (API) and the American Fuel & Petrochemicals Manufacturers (AFPM). He also serves on the board of directors of JobsOhio. Mr. Heminger is a member of the Oxford Institute for Energy Studies. Mr. Heminger began his career with Marathon in 1975 and has served in a variety of capacities. In addition to holding various finance and administration roles, he spent three years in London as part of the Brae Project and served in several marketing and commercial positions with Emro Marketing Company, the predecessor of Speedway LLC. He also served as president of Marathon Pipe Line Company. Mr. Heminger was named vice president of Business Development for Marathon Ashland Petroleum LLC upon its formation in 1998, senior vice president in 1999 and executive vice president in 2001. Mr. Heminger was appointed president of Marathon Petroleum Company LLC and executive vice president Marathon Oil Corporation—Downstream in 2001. He was named president and chief executive officer of Marathon Petroleum Corporation on July 1, 2011, and to his current position in 2016. Mr. Heminger earned a bachelor's degree in accounting from Tiffin University in 1976 and a master's degree in business administration from the University of Dayton, Ohio, in 1982. He is a graduate of the Wharton School Advanced Management Program at the University of Pennsylvania.

Qualifications: Mr. Heminger has extensive knowledge of all aspects of our business. As our chief executive officer, he leverages that expertise in advising on the strategic direction of the Partnership and apprising the board on issues of significance to the Partnership and our industry. Mr. Heminger also serves on one outside public company board of directors, which affords him a fresh perspective on management and governance. Mr. Heminger brings to our board energy industry expertise and a breadth of transactional experience.

Other Public Company Directorships: Marathon Petroleum Corporation (2011 to present); Fifth Third Bancorp (2006 to present)

Donald C. Templin. Donald C. Templin was elected a member of the board of directors of our general partner in June 2012. He is president of our general partner and executive vice president of MPC. He is a member of the board of directors of Calgon Carbon Corporation. Mr. Templin is on the Downstream Committee of API. He is active in a number of charitable organizations, including the United Way. Mr. Templin was appointed senior vice president and chief financial officer of MPC in 2011, vice president and chief financial officer of our general partner in 2012, executive vice president, supply, transportation and marketing of MPC in 2015, and assumed his current positions in 2016. Prior to joining MPC in 2011, Mr. Templin was the managing partner of the audit practice for PricewaterhouseCoopers LLP ("PwC") in Georgia, Alabama and Tennessee. While at PwC, he completed more than 25 years of providing auditing and advisory services to a wide variety of private, public and multinational companies. Mr. Templin joined PwC in Pittsburgh in 1984. While at PwC, he went on to serve in London, Kazakhstan and Baltimore before assuming his position in Atlanta in 2009. Mr. Templin is a graduate of Grove City College, a certified public accountant and a member of the American Institute of Certified Public Accountants. He attended the Oxford Institute for Energy Studies in 2012.

Qualifications: As the current president of our general partner and executive vice president of MPC, along with his prior positions with both companies, Mr. Templin has direct insight into all aspects of our business, from an operational and commercial perspective, and in the areas of accounting, audit and financial management. Mr. Templin also has a long and successful background in public accounting for energy sector clients and draws from that experience on matters relating to public company financial reporting requirements. Mr. Templin serves on one outside public company board of directors, which provides him exposure to perspectives on management and governance that may differ from those of our general partner. Mr. Templin brings his extensive energy industry background, particularly his expertise in accounting, financial reporting and strategic planning, to his service on our board.

Other Public Company Directorships: Calgon Carbon Corporation (2013 to present)

Pamela K. M. Beall. Pamela K. M. Beall was elected a member of the board of directors of our general partner in January 2014 and is executive vice president and chief financial officer of our general partner. She also serves on the board of directors of National Retail Properties, Inc., the board of trustees of The University of Findlay, and is a member of The Ohio Society of CPAs. Ms. Beall began her career with Marathon in 1978 as an auditor and held positions with the Corporate Risk and Environmental Affairs and Domestic Funds organizations before transferring to USX Corporation as general manager, Treasury Services. She was vice president and treasurer at NationsRent, Inc. and OHM Corporation, and served on the boards of directors of System One Services, Inc. and Boyle Engineering. Ms. Beall rejoined Marathon in 2002, as manager, Business Development for Marathon Ashland Petroleum LLC. She was named director, Corporate Affairs in 2003 and appointed director, Business Development in 2005. She then served as organizational vice president, Business Development—Downstream for Marathon Petroleum Company LLC in 2006. Ms. Beall was named vice president of Global Procurement for Marathon Oil Company in 2007, vice president of Products, Supply & Optimization for Marathon Petroleum Company LLC in 2010 and vice president, Investor Relations and Government & Public Affairs in 2011. She was named president of our general partner and senior vice president, Corporate Planning, Government and Public Affairs of MPC in 2014. Ms. Beall was named executive vice president, Corporate Planning and Strategy of our general partner and then assumed her current position in 2016. Ms. Beall graduated from The University of Findlay with a bachelor’s degree in accounting in 1978. In 1984, she received her master’s degree in business administration from Bowling Green State University. Ms. Beall is licensed as a certified public accountant in Ohio. She attended the Oxford Institute for Energy Studies in 2003.

Qualifications: As the executive vice president and chief financial officer of our general partner, Ms. Beall has extensive energy industry experience, specifically in the areas of finance and accounting, business development, risk management, procurement, investor relations and government affairs. She has also served as a senior executive in the environmental remediation and industrial products rental sectors, as well as on the boards of directors of other companies. Ms. Beall brings to our board her knowledge of the Partnership’s business and operations, and her perspective on its prospects for growth.

Other Public Company Directorships: National Retail Properties, Inc. (2016 to present)

Michael L. Beatty. Michael L. Beatty was elected a member of the board of directors of our general partner effective December 4, 2015, at the time of the MarkWest Merger in fulfillment of our obligations under the merger agreement with MarkWest to appoint two directors identified by MarkWest to the board of our general partner effective at the close of the merger. Mr. Beatty was a member of the board of directors of MarkWest’s general partner from 2008 until the MarkWest Merger, and served on the MarkWest board’s nominating and corporate governance committee and compensation committee. He also serves on the board of directors of the Cystic Fibrosis Foundation. Mr. Beatty is a former chairman of the law firm of Beatty & Wozniak, P.C. headquartered in Denver, Colorado, with a practice focused exclusively on energy, including oil and gas exploration, regulatory affairs, public lands, litigation and title. Prior to being appointed to the board of directors of MarkWest Energy Partners, L.P. in 2008, he served as a member of the board of directors of MarkWest Hydrocarbon. Mr. Beatty began his career in the energy industry as in-house counsel for Colorado Interstate Gas Company, and ultimately became executive vice president, general counsel and director of The Coastal Corporation. He also served as chief of staff to Governor Roy Romer of Colorado. Mr. Beatty is a graduate of the Harvard Law School.

Qualifications: Through his experience as director, officer and legal counsel of various energy companies, Mr. Beatty has extensive experience in the oil and gas industry, including significant experience in government energy policy and energy regulation. Mr. Beatty brings to our board his vast knowledge of the energy business, an acute awareness of current developments in the industry, as well as extensive historical knowledge of MarkWest.

Other Public Company Directorships: Denbury Resources Inc. (2007-2015); MarkWest Energy GP, L.L.C. (2008-2015)

David A. Daberko. David A. Daberko was elected a member of the board of directors of our general partner effective October 2012. Mr. Daberko serves on the boards of directors of MPC and RPM International, Inc. He joined National City Bank in 1968, and went on to hold a number of management positions with National City. In 1987, Mr. Daberko was elected deputy chairman of National City Corporation, a financial services corporation, now part of PNC Financial Services Group, Inc., and president of National City Bank in Cleveland. He served as president and chief operating officer from 1993 until 1995, when he was named chairman of the board and chief executive officer. He retired as chief executive officer in June 2007 and as chairman of the board in December 2007. Mr. Daberko holds a bachelor’s degree from Denison University and a master’s degree in business administration from Case Western Reserve University.

Qualifications: With nearly forty years of experience in the banking industry, including twelve years as the chairman and chief executive officer of a large financial services corporation, Mr. Daberko has extensive knowledge of the financial services and investment banking sectors. He also has considerable experience from his service as a member of other public company boards of directors, including within the energy industry. Mr. Daberko brings to our board his knowledge of public company financial reporting requirements and an understanding of the energy business.

Other Public Company Directorships: Marathon Petroleum Corporation (2011 to present); RPM International, Inc. (2007 to present); Williams Partners GP LLC (2010 to 2015)

Timothy T. Griffith. Timothy T. Griffith was elected a member of the board of directors of our general partner effective March 2015. Mr. Griffith is also senior vice president and chief financial officer of MPC. Prior to joining MPC in 2011, he served as vice president and treasurer of Smurfit-Stone Container Corporation, where he had executive responsibility for the company's investor interface and treasury operations, including capital structure, cash management, insurance and investment oversight. Mr. Griffith also served as vice president and treasurer of Cooper-Standard Automotive, as assistant treasurer of Lear Corporation, as the capital planning officer for Comerica Incorporated and as a derivatives specialist with Citicorp Securities. He was vice president, Finance and Investor Relations, and treasurer of MPC and our general partner, and the vice president and chief financial officer of our general partner before assuming his current position in 2015. Mr. Griffith earned a bachelor's degree in economics from Michigan State University and a master's degree in business administration from the University of Michigan. He is also a chartered financial analyst, a designation he has held since 1995. He attended the Oxford Institute for Energy Studies in 2013.

Qualifications: Mr. Griffith has extensive experience and held a variety of roles in finance over the course of his career, dating from his first position in banking, his increasing responsibilities at several publicly traded and privately sponsored businesses, continuing through his roles managing the financial affairs of both MPC and our general partner, having served as the treasurer and chief financial officer of both entities. Mr. Griffith has been deeply involved in the Partnership's strategy formation and execution.

Other Public Company Directorships: None within the last five years

Christopher A. Helms. Christopher A. Helms was elected a member of the board of directors of our general partner effective October 2012. Mr. Helms is president and chief executive officer of US Shale Management Company, a wholly owned subsidiary of US Shale Energy Advisors LLC. He also serves on the board of directors of Range Resources Corporation. Mr. Helms is the co-founder of US Shale Energy Advisors LLC, a privately owned entity engaged in the development, ownership and operation of midstream energy assets. From 2005 until his retirement in 2011, Mr. Helms served in various capacities with NiSource Inc. and its affiliate, NiSource Gas Transmission and Storage, including as executive vice president and group chief executive officer. He was group president, pipeline of NiSource Inc. from 2005 to 2008, where he was also a member of the Executive Council and the Corporate Risk Management Committee. He served as chief executive officer and executive director of NiSource Gas Transmission and Storage from 2008 to 2011. At NiSource, Mr. Helms was responsible for leading the company's interstate gas transmission, storage and midstream businesses. Prior to his tenure at NiSource, Mr. Helms held senior executive positions with CMS Energy Corporation, and subsidiaries of Duke Energy Corporation and PanEnergy Corp. from 1990 to 2005. Mr. Helms graduated with a bachelor of arts degree from Southern Illinois University at Edwardsville and a juris doctor degree from the Tulane University School of Law.

Qualifications: As the chief executive officer of an energy midstream logistics company and a former senior executive with several vertically integrated natural gas companies, Mr. Helms has significant experience in the oil and natural gas businesses. His background includes overseeing joint ventures and mergers and acquisitions within the midstream energy sector. He draws upon his prior capacity supervising financial reporting functions in his role as one of our named audit committee financial experts. Through his service on other public company boards of directors, Mr. Helms has been exposed to a variety of management styles and governance approaches, and he serves as chair of our conflicts committee. He brings his considerable midstream energy expertise, particularly in operations and business combinations, and his skills in the areas of finance, accounting, compliance, strategic planning and risk oversight, to his service on our board.

Other Public Company Directorships: Range Resources Corporation (2014 to present); Questar Corporation (2013 to 2016)

Garry L. Peiffer. Garry L. Peiffer was elected a member of the board of directors of our general partner in June 2012. Mr. Peiffer retired as president of our general partner and as executive vice president, Corporate Planning and Investor & Government Relations of MPC in 2014. He is a member of the board of directors of the Fifth Third Bank (Northwestern Ohio). Mr. Peiffer is also a member of the boards of trustees of the Blanchard Valley Health System and the Findlay-Hancock County Community Foundation, and serves on the Blanchard Valley Port Authority Board. Mr. Peiffer began his career with Marathon Oil Company in 1974. During his career, he held a variety of management positions with increasing responsibilities. These responsibilities included supervisor of employee savings and retirement plans, controller of Speedway Petroleum Corporation and numerous other marketing and logistics positions. In 1987, Mr. Peiffer was appointed to the president's Commission on Executive Exchange serving for a year in the Pentagon as special assistant to the Assistant Secretary of Defense for Production and Logistics. In 1988, he returned to Marathon Oil and was named vice president of Finance and Administration for Emro Marketing Company. He served as assistant controller, Refining, Marketing and Transportation beginning in 1992. Mr. Peiffer was named senior vice president of Finance and Commercial Services for Marathon Ashland Petroleum LLC in 1998, executive vice president of MPC in 2011 and president of our general partner in 2012. Mr. Peiffer graduated with a bachelor's degree in accounting from Bowling Green State University in 1974 and passed the certified public accountant exam in Ohio that same year.

Qualifications: As the retired president of our general partner and retired executive vice president, Corporate Planning and Investor & Government Relations of MPC, Mr. Peiffer has an extensive energy industry background. His significant career accomplishments include leading finance organizations, successfully realizing several joint ventures and corporate reorganizations and implementing new information technology solutions. As a recognized leader in the industry, Mr. Peiffer led the Partnership through the initial public offering process and in its first year of operations. Mr. Peiffer brings a wealth of knowledge and market expertise to his role on our board.

Other Public Company Directorships: None within the last five years

Dan D. Sandman. Dan D. Sandman was elected a member of the board of directors of our general partner effective October 2012. Mr. Sandman is an adjunct professor at The Ohio State University Moritz College of Law, where he has taught corporate governance law since 2007. He has served on the board of directors of Roppe Corporation, a privately held company, since 1987. Additionally, Mr. Sandman serves on the boards of directors of the Heinz History Center, the Carnegie Science Center, the Carnegie Hero Commission, the Pittsburgh Opera and Grove City College. He has served as a court-appointed mediator of commercial cases pending in U.S. federal courts and has lectured on corporate governance law at Oxford University. Mr. Sandman began his career with Marathon in 1973 and served in a series of legal positions of increasing responsibility. In 1986, Mr. Sandman was appointed general counsel and secretary of Marathon Oil Company, and in 1993 he was named general counsel and secretary of USX Corporation. Upon the spinoff of United States Steel Corporation from USX in 2002, Mr. Sandman was named vice chairman of the board of directors and chief legal and administrative officer of United States Steel, where he served until his retirement in 2007. During his time with United States Steel, Mr. Sandman was responsible at various times for management and oversight of aspects of Human Resources, Executive Compensation, Public Relations, Environmental and Government Affairs, as well as the Law Organization and the corporate secretary's office. Mr. Sandman graduated with a bachelor of arts degree from The Ohio State University in 1970 and a juris doctor degree from The Ohio State University College of Law in 1973. Mr. Sandman attended the Stanford Executive Program in 1989.

Qualifications: As the former vice chairman and chief legal officer of a large industrial firm, Mr. Sandman has considerable experience in the legal affairs, transactional law, regulatory compliance and corporate governance, ethics and risk management matters that may arise in the context of the Partnership's business. He has also served as general counsel of a large integrated oil company and thus has an energy industry background. Mr. Sandman teaches corporate governance law as an adjunct professor and serves on the board of directors of a private company engaged in manufacturing. Mr. Sandman brings to our board his valuable perspective, specifically on matters of strategic focus, governance and leadership.

Other Public Company Directorships: CNX Coal Resources GP LLC (2017 to present)

Frank M. Semple. Frank M. Semple was elected a member of the board of directors of our general partner effective December 4, 2015, at the time of the MarkWest Merger in fulfillment of our obligations under the merger agreement with MarkWest to appoint two directors identified by MarkWest to the board of our general partner effective at the close of the merger. He also serves as a member of the board of directors of MPC. Mr. Semple was appointed vice chairman of our general partner effective at the close of the MarkWest Merger and served in that position until his retirement effective November 1, 2016. Prior to joining our general partner, Mr. Semple was the president and chief executive officer of MarkWest beginning on November 1, 2003, and was elected chairman of the board in 2008. Prior to joining MarkWest he completed a 22-year career with The Williams Companies, Inc. ("Williams") and WilTel Communications. He served as the chief operating officer of WilTel Communications, senior vice president/general manager of Williams Natural Gas Company, vice president of operations and engineering for Northwest Pipeline Company and division manager for Williams Pipe Line Company. Prior to joining Williams, Mr. Semple served in the United States Navy. Mr. Semple earned a bachelor's degree in mechanical engineering from the United States Naval Academy. He has completed the Program for Management Development at Harvard Business School.

Qualifications: As the former chairman and chief executive officer of MarkWest, Mr. Semple has proven leadership abilities in managing a complex business and a deep understanding of the midstream sector. Mr. Semple has significant experience regarding operations, strategic planning, finance and corporate governance matters.

Other Public Company Directorships: Marathon Petroleum Corporation (2015 to present); MarkWest Energy GP, L.L.C. (2003-2015)

John P. Surma. John P. Surma was elected a member of the board of directors of our general partner effective October 2012. Mr. Surma is a member of the boards of directors of MPC, Ingersoll-Rand plc and Concho Resources Inc. He serves as the chair of the board of directors of the Federal Reserve Bank of Cleveland. Additionally, Mr. Surma is the chair of the board of directors of the National Safety Council and is a member of the board of directors of the University of Pittsburgh Medical Center. He was appointed by President Barack Obama to the President's Advisory Committee for Trade Policy and Negotiations and served as its vice chairman. Mr. Surma retired as the chief executive officer of United States Steel Corporation, an integrated steel producer, in September 2013, and as executive chairman in December 2013. Prior to joining United States Steel, Mr. Surma served in several executive positions with Marathon Oil Corporation. He was named senior vice president, Finance & Accounting of Marathon Oil Company in 1997, president, Speedway SuperAmerica LLC in 1998, senior vice president, Supply and Transportation of Marathon Ashland Petroleum LLC in 2000 and president of Marathon Ashland Petroleum LLC in 2001. Prior to joining Marathon, Mr. Surma worked for Price Waterhouse LLP where he was admitted to the partnership in 1987. In 1983, Mr. Surma participated in the President's Executive Exchange Program in Washington, D.C., where he served as executive staff assistant to the vice chairman of the Federal Reserve Board. Mr. Surma earned a bachelor of science degree in accounting from Pennsylvania State University in 1976.

Qualifications: As the retired chairman and chief executive officer of a large industrial firm, Mr. Surma has a broad range of experiences that shape his viewpoint on the strategic direction and operations of the Partnership. Mr. Surma brings to the board his significant experience in public accounting and in executive leadership in the energy and steel industries. His service on other public company boards of directors also affords him a perspective that is particularly valuable to our board.

Other Public Company Directorships: Marathon Petroleum Corporation (2011 to present); Concho Resources Inc. (2014 to present); Ingersoll-Rand plc (2012 to present); United States Steel Corporation (2001 to 2013); Bank of New York Mellon (2007 to 2012)

C. Richard Wilson. C. Richard Wilson was elected a member of the board of directors of our general partner effective October 2012. Mr. Wilson is the owner of Plough Penny Associates, LLC, a consulting firm that offers services in the finance, marketing and general management disciplines. Mr. Wilson is an officer and serves on the board of directors of Minsi Trails Council, Inc., which is affiliated with the Boy Scouts of America. Mr. Wilson previously served in director and executive officer capacities with Buckeye Partners, L.P. and its general partner, Buckeye GP LLC. During his tenure with Buckeye Partners, Mr. Wilson held the positions of president and chief operating officer. While serving as chief operating officer, he was responsible for all aspects of Buckeye Partners' operations and administration. In addition to pipeline operations, such responsibilities included finance, mergers and acquisitions, investor relations, legal, regulatory compliance, engineering and human relations. Mr. Wilson was a director of Buckeye GP LLC from 1986 until 2000, holding the role of vice chairman for two years. After Mr. Wilson's retirement in 2000, he remained as a consultant to Buckeye Partners for an additional five years. Mr. Wilson graduated with a bachelor of arts degree in economics and a master's degree in business administration, both from Rutgers University.

Qualifications: As a former director and the president and chief operating officer of Buckeye Partners, L.P., Mr. Wilson's experience with the management and oversight of a master limited partnership dates back to the emergence of this business form in the pipeline industry. Mr. Wilson's background as an executive in the midstream energy sector includes, at various points in time, his responsibility for pipeline operations, engineering, corporate administration, finance, mergers and acquisitions, investor relations and regulatory compliance. He draws upon his prior capacity supervising financial reporting functions in his role as chair of the audit committee of our board and in serving as a named audit committee financial expert. Mr. Wilson brings to our board his wealth of knowledge of the energy business, which makes him a valued contributor.

Other Public Company Directorships: None within the last five years

C. Corwin Bromley. C. Corwin Bromley is executive vice president and general counsel (chief legal officer) of our general partner. He joined our general partner in December 2015, at the time of the MarkWest Merger. Prior to this appointment, Mr. Bromley was executive vice president, general counsel and secretary at MarkWest beginning in July 2013, and senior vice president, general counsel and secretary at MarkWest beginning in 2004.

Gregory S. Floerke. Gregory S. Floerke is executive vice president and chief operating officer, MarkWest operations of our general partner. He joined our general partner in December 2015, at the time of the MarkWest Merger and was named executive vice president and chief commercial officer, MarkWest assets. He assumed his current position in 2016. Prior to joining our general partner, Mr. Floerke was executive vice president and chief commercial officer at MarkWest beginning in 2015 and senior vice president, Northeast region at MarkWest beginning in 2013. Previously, Mr. Floerke held senior management positions at Access Midstream Partners, L.P. from 2011 until 2013, and One Communications Corp. from 2007 until 2011.

Randy S. Nickerson. Randy S. Nickerson is executive vice president and chief commercial officer, MarkWest assets of our general partner. He was appointed to his current position in October 2016. He also serves as the executive vice president, Corporate Strategy of MPC, effective December 4, 2015, at the time of the MarkWest Merger. Prior to these appointments, Mr. Nickerson served as chief commercial officer of MarkWest beginning in 2006 and senior vice president, Corporate Development beginning in 2003.

Paula L. Rosson. Paula L. Rosson is senior vice president and chief accounting officer of our general partner. She joined our general partner in December 2015, at the time of the MarkWest Merger. Prior to this appointment, Ms. Rosson was senior vice president at MarkWest beginning in 2014, principal accounting officer beginning in 2011, and vice president and controller beginning in 2006.

Timothy J. Aydt. Timothy J. Aydt is vice president, operations of our general partner and president of Marathon Pipe Line. He was appointed to his current positions effective January 1, 2017. Prior to these appointments, Mr. Aydt served as the Terminal, Transport and Rail general manager of MPC beginning in 2013, and the project director for the Detroit Heavy Oil Upgrade Project beginning in 2008.

Molly R. Benson. Molly R. Benson is vice president, corporate secretary and chief compliance officer of our general partner and of MPC. She was appointed to her current position effective March 1, 2016. Prior to this appointment, Ms. Benson was assistant general counsel, Corporate and Finance of MPC beginning in April 2012, and group counsel, Corporate and Finance of MPC beginning in 2011.

Peter Gilgen. Peter Gilgen is vice president and treasurer of our general partner. He was appointed to his current position effective February 1, 2017. Prior to this appointment, Mr. Gilgen was assistant treasurer of MPC beginning in 2012, and Corporate Finance and Banking manager beginning in 2011.

Frank A. Quintana. Frank A. Quintana is vice president, Tax of our general partner. He joined our general partner in December 2015, at the time of the MarkWest Merger. Prior to this appointment, Mr. Quintana was vice president, Tax, beginning in 2012 and director, Tax, beginning in 2005 at MarkWest.

John S. Swearingen. John S. Swearingen was appointed vice president, crude oil and refined products pipelines and chief operating officer of pipeline operations in 2015 and was appointed senior vice president, Transportation and Logistics of MPC in 2015. Prior to this appointment, Mr. Swearingen was vice president and chief operating officer since 2014. Previously, Mr. Swearingen served in various leadership positions, including as vice president, Health, Environment, Safety and Security beginning in 2011 and president of Marathon Pipeline LLC beginning in 2009.

GOVERNANCE PRINCIPLES

Our governance principles are available on our website at http://ir.mplx.com by selecting "Corporate Governance" and clicking on "Governance Principles." In summary, our Governance Principles provide the functional framework of the board of directors of our general partner, including its roles and responsibilities. These principles also address board independence, committee composition, the process for director selection and director qualifications, the board's performance review, the board's planning and oversight functions, director compensation and director retirement and resignation.

LEADERSHIP STRUCTURE OF THE BOARD

As provided in our governance principles, our board of directors does not have a policy requiring the roles of chairman of the board and chief executive officer to be filled by separate persons or requiring the chairman of the board to be a non-management director. Mr. Heminger, our general partner's chief executive officer, serves as chairman of the board. Our board has determined that due to his extensive knowledge of all aspects of the Partnership's business, as well as the continued relationship between the Partnership and MPC, Mr. Heminger is in the best position to lead the board as its chairman.

Our governance principles also provide that when the role of chairman of the board is filled by the chief executive officer, the board may appoint an independent director as a "lead director" to preside over executive sessions of the board or other board meetings when the chairman is absent. Dan D. Sandman, an independent director, serves as the "lead director" of the board of directors of our general partner.

The leadership structure of our board, with the combined role of chairman and chief executive officer and the independent oversight promoted by our lead director, offers a balanced approach that our board believes serves the Partnership well at this time.

COMMUNICATIONS FROM INTERESTED PARTIES

All interested parties may communicate directly with our independent directors by submitting a communication in an envelope addressed to the "Board of Directors (non-management members)" in care of the corporate secretary of our general partner, MPLX GP LLC, 200 East Hardin Street, Findlay, Ohio 45840. Additionally, interested parties may communicate with our audit and conflicts committee chairs and the independent directors, individually or as a group, by sending an e-mail to the following e-mail addresses:

Audit Committee Chair	auditchair@mplx.com
Conflicts Committee Chair	conflictschair@mplx.com
Independent Directors	non-managedirectors@mplx.com

The corporate secretary of our general partner will forward to the directors all communications that, in the corporate secretary's judgment, are appropriate for consideration by the directors. Examples of communications that would not be considered appropriate include commercial solicitations.

BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act, as amended, requires the directors and executive officers of our general partner and persons who own more than 10 percent of a registered class of our equity securities, to file reports of beneficial ownership on Form 3 and changes in beneficial ownership on Forms 4 or 5 with the SEC. Based solely on our review of the reporting forms and written representations provided to us from the persons required to file reports, we believe that each of the directors and executive officers of our general partner and persons who own more than 10 percent of a registered class of our equity securities has complied with the applicable reporting requirements for transactions in our equity securities during the fiscal year ended December 31, 2016.

CODE OF BUSINESS CONDUCT

Our code of business conduct is available on our website at http://ir.mplx.com by selecting "Corporate Governance" and clicking on "Code of Business Conduct."

CODE OF ETHICS FOR SENIOR FINANCIAL OFFICERS

Our code of ethics for senior financial officers is available on the Partnership's website at http://ir.mplx.com by selecting "Corporate Governance" and clicking on "Code of Ethics for Senior Financial Officers." This code of ethics applies to our chairman of the board of directors and chief executive officer, chief financial officer, chief accounting officer, controller and treasurer and other persons performing similar functions, as well as to those designated as senior financial officers by our chairman and chief executive officer or our audit committee.

Under this code of ethics, these senior financial officers shall, among other things:

- act with honesty and integrity, including the ethical handling of actual or apparent conflicts of interest between personal and professional relationships;
- provide full, fair, accurate, timely and understandable disclosure in reports and documents filed with, or submitted to, the SEC, and in other public communications;
- comply with applicable laws, governmental rules and regulations, including insider trading laws; and
- promote the prompt internal reporting of potential violations or other concerns related to this code of ethics to the chair of the audit committee and to the appropriate person or persons identified in the code of business conduct.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The chairman and the independent directors of our board review compensation related matters for our general partner. During 2016, none of our general partner's executive officers served as a member of a compensation committee or board of directors of any unaffiliated entity that has an executive officer serving as an independent director on our board. Gary R. Heminger serves as an officer and director of our general partner and MPC. Frank M. Semple serves as a director of our general partner and MPC and served as an executive officer of our general partner until his retirement in 2016.

Item 11. Executive Compensation

COMPENSATION COMMITTEE REPORT

The chairman of the board and independent directors of our general partner (for purposes of this report and certain disclosures made within the following Compensation Discussion and Analysis, the "Committee") have reviewed and discussed MPLX LP's Compensation Discussion and Analysis for 2016 with MPLX LP's management. Based on its review and discussions, the Committee has recommended to the board of directors of our general partner that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

Gary R. Heminger, Chairman
Michael L. Beatty
David A. Daberko
Christopher A. Helms
Garry L. Peiffer
Dan D. Sandman
John P. Surma
C. Richard Wilson

COMPENSATION DISCUSSION AND ANALYSIS

In this section, we describe the material components of our general partner's executive compensation program for our named executive officers ("NEOs") and we explain how and why 2016 compensation decisions were made. We recommend that this compensation discussion and analysis be read in conjunction with the tabular and narrative disclosures in the "Executive Compensation" section of this Annual Report on Form 10-K.

Named Executive Officer Compensation

Our NEOs consist of the principal executive officer ("PEO"), each principal financial officer ("PFO") who served in the position during 2016, and the next three most highly compensated executive officers of our general partner as of December 31, 2016. The names and titles of our six NEOs as of that date were as follows:

Name	Title
Gary R. Heminger	Chairman of the Board and Chief Executive Officer
Pamela K.M. Beall	Executive Vice President and Chief Financial Officer
Nancy K. Buese	Former Executive Vice President and Chief Financial Officer
Donald C. Templin	President
C. Corwin Bromley	Executive Vice President and General Counsel (Chief Legal Officer)
Gregory S. Floerke	Executive Vice President and Chief Operating Officer, MarkWest Operations

Ms. Buese resigned effective November 1, 2016. Ms. Beall was appointed Executive Vice President and Chief Financial Officer on October 6, 2016.

Overview

We do not directly employ any of the personnel responsible for managing and operating our business. Instead, we contract with MPC to provide the necessary personnel, all of whom are directly employed by MPC or one of its affiliates. As consideration for MPC's and its affiliates' provision of these services, we pay MPC a fixed amount that reflects the cost incurred by MPC and its affiliates in providing the services of our executive officers, in accordance with the terms of the omnibus agreement.

Mr. Heminger generally devotes less than a majority of his total business time to our general partner and us and receives compensation from MPC that is not intended as remuneration for the services he provides to our business (including the business of our general partner). With respect to the services he provides to our business, we reimburse MPC for the fixed fee amount in accordance with the terms of the omnibus agreement. Mr. Heminger's fixed fee and his long-term incentive grants made by our general partner, which represent all of the material elements of his compensation attributable to the services he provides to our business, are disclosed below. In 2016, Mses. Beall and Buese and Messrs. Bromley and Floerke devoted 100 percent of their total business time to our business; accordingly, all of the material elements of their compensation are disclosed below. Mr. Templin devoted 90 percent of his total business time to our business; thus, the material elements of his compensation for the services he provides to our business are disclosed below, subject to appropriate proration.

Our general partner has adopted the MPLX 2012 Plan for the benefit of eligible officers, employees, and directors of our general partner and its affiliates, including MPC, who provide services to our business. Any award under the MPLX 2012 Plan for our NEOs must be first recommended by the compensation committee of the board of directors of MPC (the "MPC Compensation Committee"). If a recommendation is made, an award will only be granted to one of our NEOs if it is approved by the board of directors of our general partner, which is typically done on an annual basis.

Except with respect to awards that may be granted under our MPLX 2012 Plan, all responsibility and authority for compensation-related decisions for our NEOs remain with the MPC Compensation Committee, currently comprised of five independent directors, and are not subject to any approval by us, the board of directors of our general partner or any committees thereof. Other than awards granted under the MPLX 2012 Plan, MPC has the ultimate decision-making authority with respect to the total compensation of its and its subsidiaries' executive officers and employees. The fixed amount charged to us for the services of our NEOs is provided for in the omnibus agreement as previously described in this Annual Report on Form 10-K.

All final determinations with respect to awards under the MPLX 2012 Plan will be made by the board of directors of our general partner or any committee thereof that may be established for such purpose.

Compensation Consultants

Our general partner does not have a standing compensation committee, and its board of directors has not hired its own compensation consultant. BDO USA, LLP and Pay Governance, LLC have been engaged to provide compensation consulting services and benchmarking information to the compensation department and executive management of MPC. The advice these consultants provide to MPC is typically shared with the board of directors of our general partner for use in making certain compensation decisions with respect to our NEOs.

ELEMENTS OF COMPENSATION

Base Compensation

Our NEOs earn a base salary for their services to MPC and to us, which is paid by MPC or its affiliates. We incur only a fixed expense per month with respect to the compensation paid to each of our NEOs, as provided for in the omnibus agreement. As of December 31, 2016, we incurred the annualized fixed fee for Mr. Heminger of $1,220,000. The MPC Compensation Committee made the following adjustments to our NEOs' base salary in 2016, which was paid by MPC:

Name	Title	Previous Base Salary ($)	Base Salary Effective Dec. 31, 2016 ($)	Increase (%)
Pamela K.M. Beall	Executive Vice President and Chief Financial Officer	475,000	525,000	10.5
Nancy K. Buese	Former Executive Vice President and Chief Financial Officer	450,000	475,000	5.6
Donald C. Templin	Executive Vice President and President MPLX	675,000	720,000	6.7
C. Corwin Bromley	Executive Vice President and General Counsel (Chief Legal Officer)	450,000	465,000	3.3
Gregory S. Floerke	Executive Vice President and Chief Operating Officer, MarkWest Operations	400,000	420,000	5.0

Ms. Beall's increase reflects an adjustment to maintain market competitiveness and her appointment as Executive Vice President and Chief Financial Officer, which became effective as of October 6, 2016. Mr. Templin's increase reflects his appointment as President, which became effective as of January 1, 2016. All other increases were made to maintain market competitiveness.

Annual Cash Bonus Payments

Ms. Beall and Messrs. Templin, Bromley and Floerke were eligible to earn an annual bonus payment under MPC's Annual Cash Bonus ("ACB") Program for the services they provide to our business. Any bonus payment made to our NEOs will be determined solely by MPC without input from us or the board of directors of our general partner. No portion of any bonus paid by MPC to our NEOs will be charged back to us under the provisions of the omnibus agreement.

The ACB program is a variable incentive program intended to motivate and reward NEOs for achieving short-term (annual) financial and operational business objectives that drive overall shareholder value while encouraging responsible risk-taking and accountability. The majority (70 percent) of the ACB is funded by pre-established financial and operational (including environmental and safety) performance measures and the remaining 30 percent is driven by a number of discretionary factors, including adjustments due to the volatility in petroleum-related commodity prices throughout the year, which makes it difficult to establish reliable, pre-determined goals.

The financial and operational performance metrics used for the 2016 ACB program were:

Performance Metric	Description	Type of Measure
Operating Income Per Barrel(1)	Measures domestic operating income per barrel of crude oil throughput, adjusted for unusual business items and accounting changes. This metric compares a group of nine integrated or downstream companies, including MPC.	Financial (relative)
EBITDA(2)	As derived from the consolidated financial statements and as disclosed to investors as part of the quarterly earnings materials.	Financial (absolute)
Mechanical Availability(3)	Measures the mechanical availability and reliability of the processing equipment in MPC's refining, pipeline, terminal and marine operations.	Operational (absolute)
Selling, General and Administrative Costs (SG&A)(4)	Actual selling, general and administrative expenses adjusted for certain items.	Financial (absolute)
MPLX LP/MarkWest Commercial Synergies	Measures revenue enhancements or cost savings at either MPLX LP or MPC resulting from the combination for which committed actions were taken in 2016.	Financial (absolute)
Responsible Care	The metrics below measure MPC's success in meeting MPC's goals for the health and safety of its employees, contractors and neighboring communities, while continuously improving on MPC's environmental stewardship commitment by minimizing MPC's environmental impact.	
Marathon Safety Performance Index(5)	Measurement of MPC's success and commitment to employee safety. Goals are set annually at best-in-class industry performance, focusing on continual improvement. This includes common industry metrics such as Occupational Safety and Health Administration (or OSHA) Recordable Incident Rates and Days Away Rates.	Operational (absolute)
Process Safety Events Score	Measures the success of MPC's ability to identify, understand and control process hazards, which can be defined as unplanned or uncontrolled releases of highly hazardous chemicals or materials that have the potential to cause catastrophic fires, explosions, injury, plant damage and high-potential near misses or toxic exposures.	Operational (absolute)

Performance Metric	Description	Type of Measure
Designated Environmental Incidents	Measures environmental performance and consists of tracking certain: a) releases of hazardous substances into air, water or land; b) permit exceedences; and c) government agency enforcement actions.	Operational (absolute)
Quality	Measures the impact of product quality incidents and cumulative costs to MPC (no Category 4 Incident, and costs of Category 3 Incidents).(6)	Operational (absolute)

(1) This is a per barrel measure of throughput—U.S. downstream segment income adjusted for certain items. It includes a total of nine comparator companies (including MPC). Comparator company income is adjusted for special items or other like items as adjusted by MPC. The comparator companies for 2016 were: BP p.l.c.; Chevron Corporation; ExxonMobil Corporation; HollyFrontier Corporation; PBF Energy; Phillips 66; Tesoro Corporation; and Valero Energy Corporation. This is a non-GAAP performance metric which is calculated as income before taxes, as presented in MPC's audited consolidated financial statements, as adjusted, divided by the total number of barrels of crude oil throughput at the peer's respective U.S. refinery operations. To ensure consistency of this metric when comparing results to the comparator group, adjustments to MPC's and peer company segment income before taxes are sometimes necessary to remove certain items reflected in their results such as the gain/loss on assets, certain asset impairment expense or tax law changes.

(2) This is a non-GAAP performance metric. It is calculated as earnings before interest and financing costs, interest income, income taxes, depreciation and amortization expense, impairment expense and inventory market valuation adjustments.

(3) Mechanical availability represents the percentage of capacity available for critical downstream equipment to perform its primary function for the full year.

(4) This represents SG&A costs adjusted to exclude costs related to employee bonus program accruals, pension settlement expense, insurance expense and certain other expenses.

(5) This metric excluded Speedway. In the event of a fatality, payout is determined by the MPC Compensation Committee. The OSHA Recordable Incident Rate is calculated by taking the total number of OSHA recordable incidents, multiplied by 200,000 and divided by the total number of hours worked.

(6) A Category 4 Incident is one that involves a fatality. Category 3 Incidents include those in which: MPC incurs out-of-pocket costs for incident response and recovery activities, mitigation of customer claims or regulatory penalties in excess of $50,000; a media advisory is issued; or the extenuating circumstances are deemed to be of such severity by MPC's Quality Committee that a recommendation for this category is made to the MPC Quality Steering Committee and is subsequently approved.

The threshold, target and maximum levels of performance for each performance metric were established for 2016 by evaluating factors such as performance achieved in the prior year(s), anticipated challenges for 2016, MPC's business plan and overall strategy. At the time the performance levels were set for 2016, the threshold levels were viewed as likely achievable, the target levels were viewed as challenging but achievable and the maximum levels were viewed as extremely difficult to achieve.

The table below provides both the goals for each metric and MPC's performance achieved in 2016:

Performance Metric	Threshold Level	Target Level	Maximum Level	Performance Achieved	Target Weighting	Performance Achieved
Operating Income Per Barrel	5th or 6th Position	3rd or 4th Position	1st or 2nd Position	3rd Position (100% of target)	20.0%	20.0%
EBITDA(1)	$ 3,650	$ 4,750	$ 6,670	$4,501 (89% of target)	10.0%	8.9%
Mechanical Availability	92.4%	93.4%	94.4%	94.9% (200% of target)	10.0%	20.0%
Selling, General and Administrative Costs(1)	$ 1,339	$ 1,309	$ 1,279	$1,243 (200% of target)	5.0%	10.0%
MPLX LP/MarkWest Commercial Synergies	$25,000,000	$35,000,000	$50,000,000	$75,500,000 (200% of target)	5.0%	10.0%
Responsible Care						
Marathon Safety Performance Index	.90	.60	.40	0.95 (0% of target)	5.0%	0.0%
Process Safety Events Score	120	80	60	56 (200% of target)	5.0%	10.0%
Designated Environmental Incidents	72	51	30	30 (200% of target)	5.0%	10.0%
Quality	$ 500,000	$ 250,000	$ 125,000	$135,000 (192% of target)	5.0%	9.6%
				Total	**70.0%**	**98.5%**

(1) Represented in millions.

Organizational and Individual Performance Achievements for the 2016 ACB Program

At the beginning of the year, each NEO develops individual performance goals relative to their respective organizational responsibilities, which are directly related to MPC's business objectives. The subjective goals used to evaluate the individual performance of our NEOs for 2016 fell into the following general categories:

	Mr. Templin	Ms. Beall	Mr. Floerke	Mr. Bromley
Talent development, retention, succession and acquisition	✓	✓	✓	✓
Enhancement of unitholder value through return of capital and unlocking midstream asset value	✓	✓	✓	
System integration, optimization and debottlenecking	✓		✓	✓
Growth through organic expansion and acquisition opportunities	✓	✓	✓	✓
Preparation of assets for potential dropdown to MPLX LP	✓	✓	✓	✓
Progress on diversity initiatives	✓	✓	✓	✓

MPC's Chairman, President and CEO reviews the organizational and individual performance of our NEOs and makes annual bonus recommendations to the MPC Compensation Committee. Key factors considered for 2016 included:

- net income attributable to MPC decreased 59 percent to $1.17 billion in 2016 from $2.85 billion in 2015;
- MPC's TSR for 2016 of -1.8 percent compared to the median TSR of -1.5 percent for its performance unit peer group;
- sustained focus on shareholder returns with $916 million returned to shareholders through dividends and share repurchases; and
- continued integration of the MarkWest assets into the MPLX LP portfolio.

Bonus opportunities for our NEOs under the ACB program are communicated as a target percentage of annualized base salary at year end. Each of our NEOs can generally earn a maximum of 200 percent of the target award, although the MPC Compensation Committee has discretion to award each of our NEOs up to a maximum of 200 percent of target, or make no award at all, depending on MPC's overall performance and the subjective evaluation of each NEO's organizational and individual performance. The MPC Compensation Committee reviews market data provided by its compensation consultant annually with respect to competitive pay levels and sets specific bonus target opportunities for each of our NEOs. MPC does not guarantee minimum bonus payments to any of our NEOs.

2017 Bonus Payments (for 2016 Performance)

In February 2017, the MPC Compensation Committee certified the results of the performance metrics for the 2016 ACB program and applied the following formula based on performance of established metrics, organizational and individual performance to determine our NEOs' final award for 2016 performance:

Annualized Base Salary (as of 12/31/16)	X	Bonus Target (as a percent of base salary)	X	Final Award Percent (as a percent of target)	=	Final Award

Name	Annualized Base Salary (as of 12/31/16) ($)(1)	Bonus Target as a % of Base Salary (%)	Target Bonus ($)	Final Award as a % of Target (%)	Final Award ($)(2)
Pamela K.M. Beall	525,000	70	367,500	149.6	550,000
Donald C. Templin	720,000	100	720,000	162.5	1,170,000
C. Corwin Bromley	465,000	80	372,000	120.9	450,000
Gregory S. Floerke	420,000	80	336,000	126.4	425,000

(1) Mr. Templin's salary reflects his allocation of 90 percent to our General Partner.
(2) The final award is rounded to the nearest $5,000.

Long-Term Incentive Compensation

In January 2016, the board of directors of our general partner met and approved a long-term incentive (or "LTI") design whereby annual LTI awards granted to our NEOs will be in the form of performance units (50 percent) and phantom units (50 percent). Each form of LTI generally rewards performance over a multi-year period to the extent service and partnership performance conditions are achieved. The primary purpose of LTI grants to our NEOs is to advance our long-term business objectives and strengthen the alignment between the interests of our executive officers and our unitholders. The forms of LTI awards differ as illustrated below:

Form of LTI Award	Form of Settlement	Compensation Realized
Performance Units	25 percent in MPLX LP common units and 75 percent in cash	$0.00 to $2.00 per unit based on our relative ranking among a group of peer companies
Phantom Units	MPLX LP common units	Value of common units upon vesting

Performance Units

The board of directors of our general partner believes that a performance unit program serves to complement our award of phantom units. Our program benchmarks MPLX LP's Total Unitholder Return ("TUR"), relative to a peer group of midstream competitors. The board of directors of our general partner continues to believe TUR relative to a peer group is the single best metric for our performance unit program as it is commonly used by unitholders to measure a company's performance relative to others within the same industry. It also aligns the pay of our NEOs to the value delivered to our unitholders. The design of our performance unit program ensures we pay above target compensation only when our TUR is above the median of the peer group.

Under our performance unit program, TUR for MPLX LP and each of the peer group partnerships is measured over a 36-month performance cycle. Each performance cycle has four equally weighted performance periods: (1) the first 12 months, (2) the second 12 months, (3) the third 12 months and (4) the entire 36 months. MPLX LP's TUR performance percentile within the peer group is measured for each performance period with the related payout percentage determined using the following table. However, if MPLX LP's TUR is negative for a performance period, the payout percentage for that performance period is capped at target (100 percent) regardless of actual relative TUR performance percentile.

Performance Unit TUR Ranking vs. Payout

TUR Percentile	Payout (% of Target)*
100^{th} (Highest)	200%
50^{th}	100%
25^{th}	50%
Below 25^{th}	0%

* Payout for performance between quartiles will be determined using linear interpolation.

Each performance unit is dollar-denominated with a target value of $1.00. The actual payout will vary from $0.00 to $2.00 (zero percent to 200 percent of target.) The final value of the award will be determined by multiplying the simple average of the payout percentages for the four performance periods by the number of performance units granted. These awards will settle 25 percent in MPLX LP common units and 75 percent in cash.

Each peer group member's TUR is determined by taking the sum of the unit price appreciation or reduction, plus its cumulative cash distributions, for each performance period and dividing that total by the peer group member's beginning unit price for that period, as shown below.

$$\frac{\text{(Ending Unit Price – Beginning Unit Price) + Cumulative Cash Distributions}}{\text{Beginning Unit Price}}$$

The beginning and ending unit prices used for each peer group member in the TUR calculation will be the average of its respective closing unit prices for the 20 trading days immediately preceding the beginning or ending date of the applicable performance period.

The board of directors of our general partner believes that providing four performance periods over a 36-month cycle is appropriate and serves the best interest of our unitholders. By having four equally weighted performance periods, the attainment of maximum payout is more difficult to obtain as maximum payout levels can only be achieved by outperforming the TUR peer group for all four performance periods. Our design also mitigates significant market fluctuations in unit price at the beginning or end of a performance cycle and does not encourage high-risk decisions near the end of a performance cycle by limiting their impact on the overall payout of the award. In addition, the board of directors of our general partner also believes that having the maximum payout capped at $2.00 per unit helps mitigate excessive or inappropriate risk-taking.

Performance Units Granted in 2014

Performance units granted in 2014 have a performance cycle of January 1, 2014, through December 31, 2016. Additional information about these grants, including the peer group used, can be found in the "Long-Term Incentive Compensation" section of our Annual Report on Form 10-K for the year ended December 31, 2014.

In January 2017, the board of directors of our general partner approved the final TUR for the four performance periods for the 2014 performance unit grants, which are as follows:

Performance Period	Actual TUR (%)	Position	Percentile Ranking (%)	Payout (% of target)
January 1, 2014—December 31, 2014	68.4	2nd	90.91	181.82
January 1, 2015—December 31, 2015	(45.3)	10th	10.00	—
January 1, 2016—December 31, 2016	3.2	9th	20.00	—
January 1, 2014—December 31, 2016	(3.7)	9th	20.00	—
			Average:	45.46

The resulting average of 45.46 percent of target provided for a payment equal to $0.4546 per performance unit granted. The board of directors approved the following payout to Ms. Beall and Messrs. Heminger and Templin:

Name	Target Number of Performance Units	Compensation Committee Approved Payout ($)
Gary R. Heminger	1,000,000	454,600
Pamela K.M. Beall	85,000	38,641
Donald C. Templin	220,000	100,012

The payout was settled 25 percent in full value MPLX LP common units and 75 percent in cash. Mr. Bromley and Mr. Floerke were not eligible for a payout as these awards were made prior to the MarkWest Merger.

Performance Units Granted in 2015

Performance units granted in 2015 have a performance cycle of January 1, 2015, through December 31, 2017. They remain outstanding and are included in the "Outstanding Equity Awards at 2016 Fiscal Year-End" table. Additional information about these grants, including the peer group used, can be found in the "Long-Term Incentive Compensation Program" section of our Annual Report on Form 10-K for the year ended December 31, 2015.

Performance Units Granted in 2016

After an annual review of market practices, the board of directors of our general partner again made performance unit grants in February 2016. The following peer group was approved for those performance units:

- Buckeye Partners, L.P.
- Enbridge Energy Partners, L.P.
- Energy Transfer Partners, L.P.
- Enterprise Products Partners L.P.
- Magellan Midstream Partners, L.P.
- ONEOK Partners, L.P.
- Phillips 66 Partners LP
- Plains All American Pipeline, L.P.
- Sunoco Logistics Partners L.P.
- Tesoro Logistics LP
- Valero Energy Partners LP
- Western Gas Partners, LP
- Williams Partners L.P.

Holly Energy Partners, Nustar Energy L.P., and Shell Midstream Partners L.P. were removed for 2016 while Enbridge Energy Partners, L.P., Energy Transfer Partners, L.P., Enterprise Products Partners L.P., ONEOK Partners, L.P. and Williams Partners L.P. were added. These changes were primarily made to better align the peer group with the increased size and operational structure of MPLX LP after its merger with MarkWest.

The number of performance units granted to Ms. Beall and Messrs. Heminger and Templin can be found in the Grants of Plan-Based Awards table below.

Phantom Units

A phantom unit is a notional unit that entitles our NEOs to receive a common unit upon vesting, which occurs on a deferred basis on specified future dates. Grants of phantom units provide diversification of the mix of LTI awards, promote ownership of actual MPLX LP common units and encourage executive retention. Further, phantom unit grants also help our NEOs increase their holdings in MPLX LP common units and achieve established unit ownership guideline levels.

Phantom unit awards vest in equal installments on the first, second and third anniversary of the date of grant and are settled in MPLX LP common units upon vesting. Prior to vesting, recipients have no right to vote the units, and cash distributions on the underlying equity accrue and are paid in cash upon vesting.

MPC LTI Awards

Annual MPC LTI awards are granted in the form of performance units (40 percent), stock options (40 percent) and restricted stock (20 percent). The award vehicles differ as illustrated below:

MPC Performance Units	25 percent in MPC common stock and 75 percent cash	$0.00 to $2.00 per unit based on its relative TSR ranking among a group of peer companies
MPC Stock Options	Stock	Stock price appreciation from grant date to exercise date
MPC Restricted Stock	Stock	Full value of stock upon vesting

Due to the nature of LTI awards, the actual long-term compensation value realized by our NEOs will depend on the price of the underlying stock at the time of settlement. The 2016 LTI awards were based on an intended dollar value rather than a specific number of performance units, stock options or shares of restricted stock.

MPC granted the 2016 LTI awards to Ms. Beall on March 1, 2016. The exercise price for stock options is equal to the closing price of a share of MPC common stock on the grant date, or the first trading day thereafter if the grant date is not a trading day. We discuss each of the LTI award vehicles in more detail below.

MPC Performance Units

The MPC Compensation Committee believes a performance unit program serves as a complement to stock options and restricted stock. The program benchmarks MPC's TSR relative to a peer group of oil industry competitors and a market index. This relative evaluation allows for the cyclicality of its business and commodity prices (crude oil) to be recognized and prevents volatility from directly advantaging or disadvantaging the payout of the award beyond that of its peers. The MPC Compensation Committee continues to believe that TSR relative to a peer group is the single best metric for its performance unit program as it is commonly used by shareholders to measure a company's performance relative to others within the same industry. It also aligns the compensation of its NEOs with the value delivered to its shareholders. The design of the performance unit program ensures MPC pays above target compensation only when its TSR is above the median of the peer group.

Under its program, TSR for MPC and each of the peer group companies is measured over a 36-month performance cycle. Each performance cycle has four measurement periods: (1) the first 12 months, (2) the second 12 months, (3) the third 12 months, and (4) the entire 36-month period. MPC's TSR performance percentile within the peer group is measured for each performance period, with the related payout percentage determined using the following table. However, if MPC's TSR is negative for a performance period, the payout percentage for that performance period is capped at target (100 percent) regardless of actual relative TSR performance percentile.

Performance Unit TSR Ranking vs. Payout

TUR Percentile	Payout (% of Target)*
100th (Highest)	200%
50th	100%
25th	50%
Below 25th	0%

* Payout for performance between quartiles will be determined using linear interpolation.

Each performance unit is dollar-denominated with a target value of $1.00. The actual payout may vary from $0.00 to $2.00 (zero percent to 200 percent of target). The final value of the award will be determined by multiplying the simple average of the payout percentages for the four measurement periods by the number of performance units granted. These grants will then settle 25 percent in MPC common stock and 75 percent in cash.

TSR is determined by taking the sum of a company's stock price appreciation or reduction, plus its cumulative dividends, for each performance period and dividing that total by the company's beginning stock price for that period, as illustrated below:

$$\frac{\text{(Ending Stock Price} - \text{Beginning Stock Price)} + \text{Cumulative Cash Dividends}}{\text{Beginning Stock Price}}$$

The beginning and ending stock prices used for MPC and each peer group member in the TSR calculation will be the average of their respective closing stock prices for the 20 trading days immediately preceding the beginning and ending date of the applicable performance period.

The MPC Compensation Committee believes that providing four measurement periods over a 36-month cycle is appropriate and serves the best interest of its shareholders. By having four equally weighted measurement periods, attaining maximum payout is more difficult as maximum payout levels can only be achieved by outperforming the TSR peer group for all four measurement periods. The design also mitigates significant market fluctuations in stock price at the beginning or end of a performance cycle and does not encourage high-risk decisions near the end of a performance cycle by limiting their impact on the overall payout of the award. In addition, the MPC Compensation Committee also believes that having the maximum payout capped at $2.00 per unit helps mitigate excessive or inappropriate risk-taking.

MPC Performance Units Granted in 2014

Performance units granted by MPC in 2014 had a performance cycle of January 1, 2014, through December 31, 2016. Additional information about these grants, including the peer group used, can be found in the "Long-Term Incentive Compensation Program" section of the MPC 2015 Proxy Statement.

In January 2017, the MPC Compensation Committee certified the final TSR for the four performance periods for the 2014 performance unit grants, which are as follows:

Performance Period	Actual TSR (%)	Position	Percentile Ranking (%)	Payout (% of target)
January 1, 2014—December 31, 2014	3.2	3rd	71.43	142.86
January 1, 2015—December 31, 2015	20.2	4th	57.14	114.28
January 1, 2016—December 31, 2016	(1.8)	5th	42.85	85.70
January 1, 2014—December 31, 2016	21.5	4th	57.14	114.28
			Average:	114.28

The resulting average of 114.28 percent of target provided for a payment equal to $1.1428 per performance unit granted. As a result, the MPC Compensation Committee approved the following payment to Ms. Beall:

Name	Target Number of Performance Shares	MPC Compensation Committee Approved Payout ($)
Pamela K.M. Beall	272,000	310,842

The results of the 2014 performance unit grant were certified by the MPC Compensation Committee and settled 25 percent in full value MPC shares and 75 percent in cash.

MPC Performance Units Granted in 2015

Performance units granted by MPC in 2015 have a performance cycle of January 1, 2015, through December 31, 2017. They remain outstanding and are included for Ms. Beall in the "Outstanding Equity Awards at 2016 Fiscal Year-End" table. Additional information about these grants, including the peer group used, can be found in the "Long-Term Incentive Compensation Program" section of the MPC 2016 Proxy Statement.

MPC Performance Units Granted in 2016

The MPC Compensation Committee made the decision to award performance unit grants in February 2016. The MPC Compensation Committee approved the following peer group for performance unit awards granted in 2016:

- Chevron Corporation
- HollyFrontier Corporation
- PBF Energy
- Valero Energy Corporation
- Phillips 66
- Tesoro Corporation
- S&P 500 Energy Index

The number of performance units granted to Ms. Beall can be found in the "Grants of Plan-Based Awards" table.

MPC Stock Options

The MPC Compensation Committee believes stock options are inherently performance-based as option holders only realize benefits if the value of the stock increases for all shareholders after the grant date. The exercise price of MPC stock options is generally equal to the per-share closing price of MPC common stock on the grant date. Stock options vest in equal installments on the first, second and third anniversary of the date of grant and have a maximum 10-year term during which an NEO may exercise the options. Option holders do not have voting, dividend, or dividend equivalent rights on the underlying stock.

The number of options granted to Ms. Beall can be found in the "Grants of Plan-Based Awards" table.

MPC Restricted Stock

Grants of restricted stock provide diversification in the mix of LTI awards, result in ownership of actual shares of stock and promote NEO retention.

The value of restricted stock awards is also variable, and the awards vest in equal installments on the first, second and third anniversary of the date of grant. Prior to vesting, recipients have voting rights but dividends declared during the restricted period are accrued and paid in cash upon vesting. Upon vesting, a one-year holding period requirement is in effect for all full-value shares received under MPC's incentive compensation plan. This holding period prevents our NEOs and other executive officers from selling any stock or performance units settled in shares for 12 months from the time the awards are vested or earned. This requirement applies to shares net of taxes at the time of vesting or distribution.

The number of restricted shares granted to Ms. Beall can be found in the "Grants of Plan-Based Awards" table.

OTHER POLICIES

Benefit Programs and Perquisites

We do not sponsor any benefit plans, programs or policies such as healthcare, life insurance, income protection or retirement benefits for our NEOs, and we do not provide them with perquisites. However, those types of benefits are generally provided to our NEOs in connection with their employment by MPC or its affiliates and are governed in all cases by the terms of the applicable plan documents. All determinations with respect to such benefits will be made by MPC, its officials, or the plans, as the case may be, without input from us or our general partner or its board of directors. MPC bears the full cost of any such programs for our NEOs and no portion of these benefits is charged back to us under the provisions of the omnibus agreement. However, we have summarized the material elements of these MPC programs below to the extent they represent a material component of our NEOs' compensation for the services they provide to our business.

Perquisites

Our NEOs are eligible for reimbursement for certain tax, estate and financial planning services up to $15,000 per year while actively employed by MPC or its affiliates and $3,000 in the year following retirement or death. The MPC Compensation Committee believes this perquisite is appropriate due to the complexities of income tax preparation for our NEOs, who may, for example, be required to make personal income tax filings in multiple states due to receiving equity compensation in the form of MPLX LP phantom units that settle in MPLX LP common units.

Our NEOs are also eligible for enhanced annual physical health examinations to promote their health and well-being. Under this program, our NEOs can receive a comprehensive physical (generally in the form of a one-day appointment), with procedures similar to those available to all other employees who participate in MPC's health program. The incremental cost of these enhanced physicals is primarily attributable to MPC-paid facilities charges and incremental charges incurred for not using facilities from which MPC receives discounts under the health plan network.

The primary use of corporate aircraft is for business purposes and must be authorized by MPC's Chairman, President and CEO or another executive officer designated by MPC's Board or MPC's Chairman, President and CEO. Occasionally, spouses or other guests will accompany our NEOs on corporate aircraft, or our NEOs may travel for personal purposes on corporate aircraft when space is available on business-related flights. When a spouse's or guest's travel does not meet the Internal Revenue Service standard for business use, the cost of that travel is imputed as income to the NEO.

Reportable values for these perquisite programs, based on the incremental costs to MPC, are included in the "All Other Compensation" column of the 2016 Summary Compensation Table.

Neither income tax assistance nor tax gross-ups are provided on executive perquisites including tax, estate and financial planning services or the personal use of corporate aircraft.

Unit Ownership Guidelines

In January 2013, the board of directors of our general partner met and approved unit ownership guidelines for our executive officers including our NEOs. As our executive officers earn a base salary from MPC and not from MPLX LP, the unit ownership guidelines were established as a fixed number of units instead of a value representing a multiple of an executive officer's annual salary. In February 2016, the board of directors of our general partner revised the unit ownership guidelines to levels it deemed more reasonable given the market value of MPLX LP common units. The guidelines are intended to align the long-term interests of our executive officers and our unitholders. Under these guidelines, executive officers are expected to hold a specified level of MPLX LP common units. The targeted levels are:

- based on the executive's position and responsibilities, and
- expected to be reached within five years of the executive officer's assumption of the position.

The unit ownership guidelines are as follows:

- Chairman of the Board and Chief Executive Officer—25,000 units;
- President—20,000 units;
- Executive Vice President—15,000 units;
- Senior Vice President—10,000 units; and
- Vice President—5,000 units.

Executive officers are not permitted to sell any units received under the MPLX 2012 Plan unless their guideline ownership levels are met and are maintained after the sale. Additionally, a one-year holding requirement prevents executive officers from selling any phantom or performance units settled in MPLX LP common units for twelve months from the time they are vested or earned. This requirement applies to units net of taxes at the time of vesting or distribution.

Prohibition on Derivatives and Hedging

In order to ensure our executive officers, including our NEOs, bear the full risk of our unit ownership, we maintain a policy that prohibits hedging transactions related to our units, or pledging or creating security interests in our units, including units in excess of a unit ownership guideline requirement.

Severance and Change in Control Arrangements

None of our NEOs have employment agreements with us, our general partner or MPC. Our NEOs are eligible to participate in MPC's Amended and Restated Executive Change in Control Severance Benefits Plan. This plan provides senior executives with severance payments and benefits in the event of a qualified termination of employment within two years of the occurrence of a change in control of MPC. All determinations with respect to such benefits would be made by MPC without input from us or our general partner or its board of directors. MPC would bear the full cost of any such payments to our NEOs and benefits and no portion of such payments would be charged back to us under the provisions of the omnibus agreement.

Our NEOs do not participate in any arrangements that would result in the payment of any amounts or provision of any benefits solely as a result of a change in control of us. However, the board of directors of our general partner approved provisions in our 2015 grant agreements and thereafter that would provide for accelerated vesting upon a qualified termination from service in connection with a change in control of MPLX LP.

If Messrs. Bromley or Floerke separate from service as a result of a forced relocation of their principal place of employment to a location more than 50 miles from their current principal place of employment, their unvested MPLX LP phantom units and MPC restricted stock received as part of their retention grants awarded in 2015 will vest and become payable. The amount payable assuming such termination occurred on December 31, 2016, based on the MPLX LP common unit and MPC stock closing prices as of that date, would have been as follows: Mr. Bromley, $3,333,008; and Mr. Floerke, $2,873,843.

Additionally, upon Messrs. Bromley's or Floerke's separation from service without cause, the separated NEO is entitled to a portion of the grant of MPLX LP phantom units received as part of their retention grants awarded in 2015. The amount payable assuming such separation of service occurred on December 31, 2016, based on the MPLX LP common unit closing price as of that date, would have been as follows: Mr. Bromley, $1,739,309; and Mr. Floerke, $1,262,799.

Recoupment/Clawback Policy

In addition to any compensation recoupment policies that apply with respect to the compensation our NEOs receive from MPC, the MPLX 2012 Plan provides that all awards granted under the MPLX 2012 Plan will be subject to clawback or recoupment in the case of certain forfeiture events. If the Partnership is required, pursuant to a determination made by the SEC or the audit committee of our general partner, to prepare a material accounting restatement due to our non-compliance with any financial reporting requirement under applicable securities laws as a result of misconduct, the audit committee may determine that a forfeiture event has occurred based on an assessment of whether an executive officer:

- knowingly engaged in misconduct;
- was grossly negligent with respect to misconduct;
- knowingly failed or was grossly negligent in failing to prevent misconduct; or
- engaged in fraud, embezzlement or other similar misconduct materially detrimental to us.

Upon a determination by the audit committee of our general partner that a forfeiture event has occurred, any grants of unvested phantom units and performance units to such executive officer would be subject to immediate forfeiture. If a forfeiture event occurred either while the executive officer is employed or within three years after termination of employment and a payment has previously been made to the executive officer in settlement of performance units, we may recoup an amount in cash or units up to (but not in excess of) the amount paid in settlement of the performance units.

These recoupment provisions are in addition to the requirements in Section 304 of the Sarbanes-Oxley Act of 2002, which provide that the Chief Executive Officer and Chief Financial Officer shall reimburse us for incentive-based or equity-based compensation, as well as any related profits received in the 12-month period prior to the filing of an accounting restatement due to non-compliance with financial reporting requirements as a result of our misconduct. Additionally, all equity grants made since 2012 include provisions making them subject to any clawback provisions required by the Dodd-Frank Act and any other "clawback" provisions as required by law or by the applicable listing standards of the exchange on which the Partnership's common units are listed for trading.

Additional Compensation Components

In the future, as MPC and/or our general partner formulate and implement the compensation programs for our executive officers, MPC and/or our general partner may provide additional or different compensation components, benefits and/or perquisites to help ensure our executive officers are provided with a balanced, comprehensive and competitive total compensation package. We, MPC and our general partner believe that it is important to maintain flexibility to adapt compensation structures on an ongoing basis to properly attract, motivate, retain and reward the top executive talent for which we, MPC and our general partner compete with other companies.

COMPENSATION-BASED RISK ASSESSMENT

Annually, the Committee reviews our policies and practices in compensating our service providers (including both executive officers and non-executives, if any) as they relate to our risk management profile.

The Committee completed this review of our 2016 programs in February 2017. As a result of this review, the Committee concluded that any risks arising from our compensation policies and practices were not reasonably likely to have a material adverse effect on our financial statements.

Summary Compensation Table

The following table summarizes the total compensation awarded to, earned by or paid to our NEOs for the services each provided to our business.

Name and Principal Position[1]	Year	Salary[2] ($)	Stock Awards[3] ($)	Option Awards[3] ($)	Non-Equity Incentive Plan Compensation[4] ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings[5] ($)	All Other Compensation[6] ($)	Total ($)
Gary R. Heminger	2016	1,220,000	1,801,593	—	—	—	—	3,021,593
Chairman of the Board	2015	1,220,000	2,239,071	—	—	—	—	3,459,071
and Chief Executive Officer	2014	1,175,000	2,160,047	—	—	—	—	3,335,047
Pamela K.M. Beall	2016	499,667	530,482	170,008	550,000	226,408	86,067	2,062,632
Executive Vice	2015	234,375	173,033	—	262,500	56,514	39,282	765,704
President and Chief Financial Officer	2014	225,000	183,603	—	—	—	—	408,603
Nancy K. Buese	2016	389,583	—	—	—	71,037	75,762	536,382
Former Executive Vice President and Chief Financial Officer	2015	34,615	4,191,872	—	—	—	—	4,226,487
Donald C. Templin	2016	720,000	1,228,353	—	1,170,000	217,355	134,794	3,470,502
President	2015	515,000	508,906	—	—	—	—	1,023,906
	2014	475,000	475,212	—	—	—	—	950,212
C. Corwin Bromley	2016	461,250	—	—	450,000	90,448	61,251	1,062,949
Executive Vice President and General Counsel	2015	34,615	3,525,011	—	—	—	—	3,559,626
Gregory S. Floerke								
Executive Vice	2016	415,000	—	—	425,000	62,847	55,179	958,026
President and Chief Operating Officer, MarkWest Operations	2015	30,769	3,092,492	—	—	—	—	3,123,261

(1) Except where indicated, amounts shown reflect only compensation amounts allocable to MPLX LP and do not include compensation amounts for other services that are not allocable to MPLX LP. For 2016, compensation amounts were allocated based on the relative percentage each NEO's business time was dedicated to MPLX LP's business. For 2016, percentage allocations for each NEO were as follows: Mr. Templin—90 percent; Mses. Beall and Buese and Messrs. Bromley and Floerke—100 percent.

(2) The amounts shown in this column reflect the annualized fixed fee for Mr. Heminger for 2016, 2015, and 2014; for Mr. Templin for 2015 and 2014; and for Ms. Beall for 2014. The amounts shown for Messrs. Bromley and Floerke for 2016 reflect three months at their January 1, 2016, annualized base salary and nine months at their April 1, 2016, annualized base salary, respectively. The amount for Ms. Beall reflects three months at her January 1, 2016, annualized base salary, her annualized base salary for the period from April 1, 2016, until October 5, 2016, and her annualized base salary for the period from October 6, 2016, until December 31, 2016. The amount shown for Ms. Buese for 2016 reflects three months at her January 1, 2016, annualized base salary and seven months at her April 1, 2016, annualized base salary.

(3) The amounts shown in this column reflect the aggregate grant date fair value in accordance with provisions of the Financial Accounting Standards Board Accounting Standards Codification 718, Compensation-Stock Compensation (FASB ASC Topic 718.) See Item 8. Financial Statements and Supplementary Data-Note 20 for assumptions used in the calculation of the amounts related to MPLX LP equity for the year ended December 31, 2016, Note 19 to financial statements as reported on our Annual Report on Form 10-K for assumptions used in the calculation of the amounts related to MPLX LP equity for the year ended December 31, 2015, and Note 16 to financial statements as reported on our Annual Report on Form 10-K for assumptions used in the calculation of the amounts related to MPLX LP equity for the year ended December 31, 2014, and Note 23 to MPC's financial statements as reported on its Annual Report on Form 10-K for the year ended December 31, 2016, for amounts related to MPC equity. The maximum value of the performance units reported in the "Unit Awards" column assuming the highest level of performance is achieved for Ms. Beall and Messrs. Heminger and Templin for 2016 is $425,000, $2,200,000, and $1,500,000, respectively; for Ms. Beall and Messrs. Heminger and Templin for 2015 is $170,000, $2,200,000, and $500,000, respectively and for Ms. Beall and Messrs. Heminger and Templin for 2014 is $170,000, $2,000,000 and $440,000, respectively.

(4) The amounts shown in this column reflect the total value of ACB awards earned in the year indicated, which were paid in the following year.

(5) The amounts shown in this column reflect the annual change in actuarial present value of accumulated benefits under the Marathon Petroleum retirement plans. See "Post-Employment Benefits for 2016" and "Marathon Petroleum Retirement Plans" sections of the "Compensation Discussion and Analysis" for more information regarding the defined benefit plans and the assumptions used in the calculation of these amounts. There are no deferred compensation earnings reported in this column as the non-qualified deferred compensation plans do not provide above-market or preferential earnings.

(6) In connection with their employment with MPC, our NEOs are eligible for limited perquisites which, together with contributions to defined contribution plans, comprise the amounts reported in the All Other Compensation column. The amounts shown in this column are summarized below:

Name	Personal Use of Company Aircraft ($)	Company Physicals[(a)] ($)	Tax & Financial Planning[(b)] ($)	Security ($)	Miscellaneous Perks & Tax Allowance Gross Ups ($)	Company Contributions to Defined Contribution Plans[(c)] ($)	Total All Other Compensation ($)
Gary R. Heminger	—	—	—	—	—	—	—
Pamela K.M. Beall	—	3,587	8,000	—	—	74,480	86,067
Nancy K. Buese	—	3,587	15,000	—	—	57,175	75,762
Donald C. Templin	—	3,587	4,612	—	—	126,595	134,794
C. Corwin Bromley	—	3,587	—	—	—	57,664	61,251
Gregory S. Floerke	—	3,587	—	—	—	51,592	55,179

(a) All MPC employees, including our NEOs, are eligible to receive an annual physical. Executives may receive an enhanced physical under the executive physical program. The amounts shown in this column reflect the average incremental cost of the executive physical program in excess of the average incremental cost of the employee physical program. Due to privacy concerns and Health Insurance Portability and Accountability Act confidentiality requirements, we do not disclose actual usage or cost of this program by individual NEOs.

(b) The amounts shown in this column reflect reimbursement for the costs of professional advice related to tax, estate and financial planning up to a specified maximum not to exceed $15,000 per calendar year. For information on this program refer to the "Perquisites" section of the "Compensation Discussion and Analysis."

(c) The amounts shown in this column reflect amounts contributed by MPC under the tax-qualified Marathon Petroleum Thrift Plan for Mses. Beall and Buese and Messrs. Templin, Bromley and Floerke, as well as under related non-qualified deferred compensation plans. See "Post-Employment Benefits for 2016" and "Marathon Petroleum Retirement Plans" sections of the "Compensation Discussion and Analysis" for more information.

Grants of Plan-Based Awards in 2016

The following table provides information regarding all plan-based awards, including cash-based incentive awards and equity-based awards (specifically stock options, restricted stock, phantom units and performance units) granted to each of our NEOs in 2016 for the services each provided to our business.

Name	Type of Award	Grant Date	Approval Date[(1)]	Estimated Future Payouts Under Non-Equity Incentive Plan Awards [(2)] Threshold ($)	Target ($)	Maximum ($)	Estimated Future Payouts Under Equity Incentive Plan Awards [(3)] Threshold ($)	Target ($)	Maximum ($)	All Other Shares of Stock or Units (#)	All Other Option Awards: Underlying Options (#)	Exercise or Base Price of Option Awards ($)	Grant Date And Option Awards[(4)] ($)
Gary R. Heminger	MPLX LP Phantom Units	3/1/2016	2/23/2016							41,463			1,100,013
	MPLX LP Performance Units	3/1/2016	2/23/2016				137,500	1,100,000	2,200,000				701,580
Pamela K.M. Beall	MPC Stock Options	3/1/2016	2/23/2016	N/A							17,052	34.63	170,008
	MPC Restricted Stock	3/1/2016	2/23/2016							2,455			85,017
	MPC Performance Units	3/1/2016	2/23/2016				21,250	170,000	340,000				97,427
	MPC Annual Cash Bonus			N/A	367,500	735,000							
	MPLX LP Phantom Units	3/1/2016	2/23/2016							8,010			212,505
	MPLX LP Performance Units	3/1/2016	2/23/2016				26,563	212,500	425,000				135,533
Nancy K. Buese	MPC Annual Cash Bonus			N/A	427,500	855,000							
Donald C. Templin	MPC Annual Cash Bonus			N/A	720,000	1,440,000							
	MPLX LP Phantom Units	3/1/2016	2/23/2016							28,270			750,003
	MPLX LP Performance Units	3/1/2016	2/23/2016				93,750	750,000	1,500,000				478,350
C. Corwin Bromley	MPC Annual Cash Bonus			N/A	372,000	744,000							
Gregory S. Floerke	MPC Annual Cash Bonus			N/A	336,000	672,000							

(1) The MPC Compensation Committee and our Board approved the awards reported in the table above for Ms. Beall and Messrs. Heminger and Templin on February 23, 2016, with a grant date of March 1, 2016.

(2) The target amounts shown in this column reflect the target annual incentive opportunity. No threshold amount is disclosed as the MPC Compensation Committee has discretion to not award an annual incentive under the ACB program. Each NEO may generally earn a maximum of 200 percent of the target.

(3) The target amounts shown in this column reflect the number of performance units granted to Ms. Beall and Messrs. Heminger and Templin. Each performance unit has a target value of $1.00. The threshold for the award is the minimum possible payout of the award, which is 12.5 percent. The threshold is achieved when the payout percentage is 50 percent for one performance period and zero percent for the other three performance periods, thus an average payout percentage of 12.5 percent for the performance cycle. The maximum payout for this award is 200 percent of target.

(4) The amounts shown in this column reflect the total grant date fair value of MPC stock options, MPC restricted stock, MPLX LP phantom units and MPC/MPLX LP performance units granted in 2016 in accordance with provisions of the Financial Accounting Standards Board Accounting Standards Codification 718, Compensation—Stock Compensation ("FASB ASC Topic 718"). The Black-Scholes value used for the stock options was $9.97 per share. The restricted stock value was based on the MPC closing stock price on the grant date listed, or the next business day if the grant date was not a business day. The price used for the March 1, 2016, grants of MPC restricted stock awards was $34.63 per share. MPC performance units are designed to settle 25 percent in MPC common stock and 75 percent in cash. The MPC performance units have a grant date fair value of $0.5731 per unit as calculated using a Monte Carlo valuation model. Assumptions used in the calculation of these amounts are included in Note 23 to MPC's financial statements as reported on its Annual Report on Form 10-K for the year ended December 31, 2016. The price used for the March 1, 2016, grants of MPLX LP phantom unit awards was $26.53 per unit. MPLX LP performance units are designed to settle 25 percent in MPLX LP common units and 75 percent in cash. The MPLX LP performance units have a grant date fair value of $0.6378 per unit as calculated using a Monte Carlo valuation model. See Item 8. Financial Statements and Supplementary Data-Note 20 for assumptions used in the calculation of these amounts.

MPC Stock Options (Option Awards)

The MPC Compensation Committee granted stock options to Ms. Beall with a grant date of March 1, 2016. All options vest in one-third increments on the first, second and third anniversaries of the date of grant and expire 10 years following the date of grant. No dividends are paid and there are no voting rights associated with stock options. In the event of the death or retirement (whether mandatory or not) of an NEO, unvested options granted to such NEO as an officer immediately vest and remain exercisable until the earlier of five years following the date of death or retirement or the original expiration date. Unvested options granted to an NEO as a non-officer immediately vest and remain exercisable until the earlier of three years following the date of death or retirement or the original expiration date. In the event of a change in control of MPC and a Qualified Termination, unvested options immediately vest and remain exercisable for the original term of the option. Upon voluntary or involuntary termination of an NEO, unvested options are forfeited. Upon voluntary or involuntary termination of an NEO for cause, vested options are cancelled. Upon involuntary termination of an NEO without cause, vested options are exercisable for 90 days following the date of termination.

MPC Restricted Stock (Stock Awards)

The MPC Compensation Committee granted restricted stock awards to Ms. Beall with a grant date of March 1, 2016, which vest in one-third increments on the first, second and third anniversaries of the grant date. Dividends accrue on the restricted stock awards and are paid upon vesting. There are voting rights associated with unvested restricted stock awards. If an NEO retires under our mandatory retirement policy, unvested restricted stock vests and accrued dividends are paid upon the mandatory retirement date (the first day of the month coincident with or following the officer's 65th birthday). In the event of the death of an NEO or a change in control of MPC, unvested restricted stock immediately vests and accrued dividends are paid. If an NEO retires or otherwise leaves MPC prior to the vesting date, unvested restricted stock and accrued but unpaid dividends are forfeited.

MPC Performance Units (Equity Incentive Plan Awards)

The MPC Compensation Committee granted performance units to Ms. Beall with a grant date of March 1, 2016. Each performance unit has a target value of $1.00 and is designed to settle 25 percent in MPC common stock and

75 percent in cash. Payout of these units could vary from $0.00 to $2.00 per unit and is tied to MPC's TSR over a 36-month period as compared to the TSR of those in its peer group for the January 1, 2016, through December 31, 2018, performance period. No dividends are paid and there are no voting rights associated with unvested performance units. If an NEO retires following the completion of one-half of the performance period (18 months) for the 2015 grant or the completion of nine months of the performance period for the 2016 grant, the NEO will be eligible to receive, at the MPC Compensation Committee's discretion, a prorated payout based on the actual results of the entire performance period. For the 2016 grant, if an NEO retires under MPC's mandatory retirement policy, outstanding performance units will fully vest, however payout will occur at the end of the full 36-month performance cycle based on the certified results of the performance cycle. In the event of the death of an NEO, all unvested performance units immediately vest at target levels. In the event of a change in control of MPC and a Qualified Termination (as defined following the "Potential Payments upon Termination or Termination in the Event of a Change in Control" table), unvested performance units for the 2015 grant immediately vest at target levels. For the 2016 grant, unvested performance units will vest and be paid out based on MPC's actual TSR performance amongst its specified peer group for the period from the date of grant to the date of the change in control, and target TSR performance for the period from the date of the change in control to the end of the performance cycle. If an NEO terminates employment under any other circumstance, unvested performance units are forfeited.

MPC Annual Cash Bonus (Non-Equity Incentive Plan Awards)

The MPC Compensation Committee established the ACB program as a variable incentive program intended to motivate and reward NEOs for achieving short-term (annual) business objectives that drive overall MPC shareholder and MPLX LP unitholder value while encouraging responsible risk-taking and accountability. Bonuses are determined at the discretion of the MPC Compensation Committee and the achievement of pre-established goals. If an NEO retires on or after July 1 of the performance year, eligibility for a bonus is at the MPC Compensation Committee's discretion. In the event of the death of an NEO during the performance period, unless otherwise determined by the MPC Compensation Committee, a target bonus will be paid. In the event of change in control of MPC, a cash severance is paid in lieu of a bonus. If an NEO terminates employment under any other circumstance, the NEO will be ineligible for a bonus payment.

MPLX LP Phantom Units (Other Unit Awards)

The MPLX Board granted phantom unit awards to Ms. Beall and Messrs. Heminger and Templin with a grant date of March 1, 2016. The phantom unit awards vest in one-third increments on the first, second and third anniversaries of the grant date. Distribution equivalents accrue on the phantom unit awards and are paid upon vesting. There are no voting rights associated with unvested phantom units. If an NEO retires under MPC's mandatory retirement policy, unvested phantom units vest and accrued distribution equivalents are paid upon the mandatory retirement date (the first day of the month coincident with or following the officer's 65th birthday.) In the event of the death of an NEO or a change in control of MPLX LP, unvested phantom units immediately vest and accrued distribution equivalents are paid. If an NEO retires or otherwise leaves MPLX prior to the vesting date, unvested phantom units and unpaid distribution equivalents are forfeited.

MPLX LP Performance Units (Equity Incentive Plan Awards)

The MPLX Board granted performance units to Ms. Beall and Messrs. Heminger and Templin with a grant date of March 1, 2016. Each performance unit has a target value of $1.00 and is designed to settle 25 percent in MPLX LP common units and 75 percent in cash. Payout of these units could vary from $0.00 to $2.00 per unit and is tied to MPLX LP's TUR over a 36-month period as compared to the TUR of those in a peer group for the January 1, 2016, through December 31, 2018, performance period. No cash distributions are paid and there are no voting rights associated with unvested performance units. If an NEO retires following the completion of one-half of the performance period (18 months) for the 2015 grant or the completion of nine months of the performance period for the 2016 grant, the NEO will be eligible to receive, at the discretion of the MPLX Board, a prorated payout based on the actual results of the entire performance period. For the 2016 grant, if an NEO retires under MPC's mandatory retirement policy, outstanding performance units will fully vest, however payout will occur at the end of the full 36-month performance cycle based on the approved results of the performance cycle. In the event of the death of an NEO, all unvested performance units immediately vest at target levels. In the event of a change in control of MPLX LP, unvested performance units for the 2015 grant immediately vest at target levels. For the 2016 grant, unvested performance units will vest and be paid out based on MPLX LP's actual TUR performance amongst its specified peer group for the period from the date of grant to the date of the change in control, and target TUR performance for the period from the date of the change in control to the end of the performance cycle. If an NEO terminates employment under any other circumstance, unvested performance units are forfeited.

Outstanding Equity Awards at 2016 Fiscal Year-End

The following table provides information regarding unvested MPLX LP phantom units, unvested MPLX LP performance units, unvested MPC restricted stock and unvested MPC performance units held by each of our NEOs as of December 31, 2016:

Name	Grant Date		Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested[2] (#)	Market Value of Shares or Units of Stock That Have Not Vested[3] ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested[4] (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights that Have Not Vested[5] ($)
Gary R. Heminger		MPLX LP					57,223	1,981,060	2,200,000	1,350,030
Pamela K.M. Beall		MPLX LP					9,282	321,343	297,500	168,071
	3/1/2016	MPC		17,052[1]	34.63	3/1/2027	2,455	123,609	170,000	582,828
Donald C. Templin		MPLX LP					31,803	1,101,020	1,000,000	556,825
C. Corwin Bromley		MPLX LP					67,389	2,333,007		
		MPC					19,861	1,000,001		
Gregory S. Floerke		MPLX LP					54,126	1,873,842		
		MPC					19,861	1,000,001		

(1) This stock option is scheduled to become exercisable in one-third increments on the first, second and third anniversaries of the grant date—March 1, 2017, March 1, 2018 and March 1, 2019.

(2) The amounts shown in this column reflect the number of unvested MPLX LP phantom units and MPC restricted stock held by each of our NEOs on December 31, 2016. Phantom unit and restricted stock grants generally are scheduled to vest in one-third increments on the first, second and third anniversaries of the grant date. The amounts shown in this column also include unvested shares of MPC restricted stock granted to Messrs. Bromley and Floerke as part of their retention grants that occurred at the time of the MarkWest Merger. These MPC restricted stock grants are scheduled to vest in full on the third anniversary of the grant date.

MPLX LP Phantom Units

Name	Grant Date	Number of Unvested Units	Vesting Dates
Gary R. Heminger	3/1/2014	6,840	3/1/2017
	3/1/2015	8,920	3/1/2017, 3/1/2018
	3/1/2016	41,463	3/1/2017, 3/1/2018, 3/1/2019
		57,223	
Pamela K.M. Beall	3/1/2014	582	3/1/2017
	3/1/2015	690	3/1/2017, 3/1/2018
	3/1/2016	8,010	3/1/2017, 3/1/2018, 3/1/2019
		9,282	
Donald C. Templin	3/1/2014	1,505	3/1/2017
	3/1/2015	2,028	3/1/2017, 3/1/2018
	3/1/2016	28,270	3/1/2017, 3/1/2018, 3/1/2019
		31,803	
C. Corwin Bromley	12/18/2015	50,240	Upon termination without cause
		17,149	12/18/2017, 12/18/2018
		67,389	
Gregory S. Floerke	12/18/2015	36,476	Upon termination without cause
		17,650	12/18/2017, 12/18/2018
		54,126	

MPC Restricted Stock

Name	Grant Date	Number of Unvested Shares	Vesting Dates
Pamela K.M. Beall	3/1/2016	2,455	3/1/2017, 3/1/2018, 3/1/2019
C. Corwin Bromley	12/18/2015	19,861	12/18/2018
Gregory S. Floerke	12/18/2015	19,861	12/18/2018

(3) The amounts shown in this column reflect the aggregate value of all unvested MPLX LP phantom units and MPC restricted stock held by each of our NEOs on December 31, 2016, using the December 30, 2016, MPLX LP common unit closing price of $34.62 per unit and MPC closing price of $50.35 per share. It also includes the value of unvested shares of MPC restricted stock granted to Messrs. Bromley and Floerke as part of their retention grants as discussed in the "Retention Agreements with Former MarkWest Executives" section of our Annual Report on Form10-K for the year ended December 31, 2015. These are valued using the MPC closing price on December 30, 2016, of $50.35 per share.

(4) The amounts shown in this column reflect the number of unvested performance units held by Ms. Beall and Messrs. Heminger and Templin on December 31, 2016. Performance unit grants awarded in 2016 have a 36-month performance cycle and are designed to settle 25 percent in MPLX LP common units/MPC stock and 75 percent in cash. Each of these performance unit grants has a target value of $1.00 and payout may vary from $0.00 to $2.00 per unit. Payout is tied to our TUR/TSR as compared to specified peer groups.

MPLX LP Performance Units

Name	Grant Date	Number of Unvested Units	Performance Period Ending Date
Gary R. Heminger	3/1/2015	1,100,000	12/31/2017
	3/1/2016	1,100,000	12/31/2018
		2,200,000	
Pamela K.M. Beall	3/1/2015	85,000	12/31/2017
	3/1/2016	212,500	12/31/2016
		297,500	
Donald C. Templin	3/1/2015	250,000	12/31/2017
	3/1/2016	750,000	12/31/2018
		1,000,000	

MPC Performance Units

Name	Grant Date	Number of Unvested Units	Performance Period Ending Date
Pamela K.M. Beall	3/1/2016	170,000	12/31/2018

(5) The amount shown in this column for MPC reflects the aggregate value of all performance units held by Ms. Beall on December 31, 2016, assuming a payout of $1.1428 per unit for the March 1, 2015, grant and $1.1428 per unit for the March 1, 2016, grant, which is the next higher performance achievement that exceeds the performance for these grants' performance period that ended December 31, 2016. The amounts shown in this column for MPLX LP reflect the aggregate value of all performance units held by Ms. Beall and Messrs. Heminger and Templin on December 31, 2016, assuming a payout of $0.7273 per unit for the March 1, 2015, grant and $0.50 per unit for the March 1, 2016, grant, which is the next higher performance achievement that exceeds the performance for these grants' performance period that ended December 31, 2016.

Option Exercises and Units Vested in 2016

The following table provides information regarding phantom units and MPC restricted stock that vested in 2016.

		Stock Awards	
Name		Number of Units/Shares Acquired on Vesting (#)	Value Realized on Vesting[1] ($)
Gary R. Heminger	MPLX LP	20,398	529,253
Pamela K.M. Beall	MPLX LP	1,456	37,803
	MPC	2,938	101,281
Donald C. Templin	MPLX LP	4,642	120,432
C. Corwin Bromley	MPLX LP	8,574	276,340
Gregory S. Floerke	MPLX LP	8,825	284,430

(1) This column reflects the actual pre-tax gain realized upon vesting of phantom units and restricted stock, which is the fair market value of the units or stock on the date of vesting.

Post-Employment Benefits for 2016

Pension Benefits

MPC provides tax-qualified pension benefits to its employees, including our NEOs, under the Marathon Petroleum Retirement Plan. In addition, MPC sponsors the Marathon Petroleum Excess Benefit Plan for the benefit of a select group of management and other employees who are "highly compensated" as defined by Section 414(q) of the Internal Revenue Code (annual compensation of $120,000 or more in 2016).

2016 Pension Benefits Table

Name	Plan Name	Number of Years of Credited Service[(1)]	Present Value of Accumulated Benefit[(2)]($)	Payments During Last Fiscal Year
Pamela K.M. Beall	Marathon Petroleum Retirement Plan	14.67 years	716,871	—
	Marathon Petroleum Excess Benefit Plan	14.67 years	1,348,690	—
Donald C. Templin	Marathon Petroleum Retirement Plan	5.50 years	121,068	—
	Marathon Petroleum Excess Benefit Plan	5.50 years	720,749	—
C. Corwin Bromley	Marathon Petroleum Retirement Plan	1.0 year	28,577	—
	Marathon Petroleum Excess Benefit Plan	1.0 year	61,871	—
Gregory S. Floerke	Marathon Petroleum Retirement Plan	1.0 year	22,179	—
	Marathon Petroleum Excess Benefit Plan	1.0 year	40,668	—

(1) The number of years of credited service shown in this column represents the number of years the NEO has participated in the plan. However, plan participation service used for the purpose of calculating each participant's benefit under the Marathon Petroleum Retirement Plan legacy final average pay formula was frozen as of December 31, 2009.

(2) The present value of accumulated benefit for the Marathon Petroleum Retirement Plan was calculated assuming a discount rate of 3.90 percent, the RP2000 mortality table for lump sums, a 96 percent lump sum election rate and retirement at age 62 (or current age, if later). In accordance with the Marathon Petroleum Retirement Plan provisions and actuarial assumptions, the discount rate for lump sum calculations varied from 1.00 percent to 1.25 percent based on the anticipated year of retirement.

The 2016 Pension Benefits Table below reflects the actuarial present value of accumulated benefits payable to each of our NEOs under the Marathon Petroleum Retirement Plan and the defined benefit portion of the Excess Plans as of December 31, 2016. These values have been determined using actuarial assumptions consistent with those used in MPC's financial statements.

Marathon Petroleum Retirement Plans

Marathon Petroleum Retirement Plan

In general, our NEOs are immediately eligible to participate in the Marathon Petroleum Retirement Plan. The Marathon Petroleum Retirement Plan is primarily designed to provide participants with income after retirement. Prior to January 1, 2010, the monthly benefit under the Marathon Petroleum Retirement Plan was equal to the following formula:

$$\left[1.6\% \times \begin{array}{c}\text{Final}\\ \text{Average Pay}\end{array} \times \begin{array}{c}\text{Years of}\\ \text{Participation}\end{array}\right] - \left[1.33\% \times \begin{array}{c}\text{Estimated}\\ \text{Primary}\\ \text{Social Security}\\ \text{Benefit}\end{array} \times \begin{array}{c}\text{Years of}\\ \text{Participation}\end{array}\right]$$

This formula is referred to as the Marathon legacy benefit formula. Effective January 1, 2010, the Marathon legacy benefit formula was amended to (i) cease future accruals of additional years of participation, and (ii) as applied to eligible NEOs, cease further compensation updates. No more than 37.5 years of participation may be recognized under the Marathon legacy benefit formula.

Eligible earnings under the Marathon Petroleum Retirement Plan include, but are not limited to, pay for hours worked, pay for allowed hours, military leave allowance, commissions, 401(k) contributions to the Marathon Petroleum Thrift Plan and incentive compensation bonuses. Age continues to be updated under the Marathon legacy benefit formula.

Benefit accruals for years beginning in 2010 are determined under a cash-balance formula. Under the cash-balance formula, each year plan participants receive pay credits equal to a percentage of compensation based on their plan points. Plan points equal the sum of a participant's age and cash-balance service:

- Participants with less than 50 points receive a seven percent pay credit;
- Participants with at least 50 but less than 70 points receive a nine percent pay credit; and
- Participants with 70 or more points receive an 11 percent pay credit.

Participants in the Marathon Petroleum Retirement Plan become fully vested upon the completion of three years of vesting service. Normal retirement age for both the Marathon legacy benefit and cash-balance formulas is 65. However, retirement-eligible participants are able to retire and receive an unreduced benefit under the Marathon legacy benefit formula after reaching age 62.

The forms of benefit available under the Marathon Petroleum Retirement Plan include various annuity options and a lump sum distribution option.

Participants are eligible for early retirement upon reaching age 50 and completing 10 years of vesting service. If an employee retires between the ages of 50 and 62 with sufficient vesting service, the amount of benefit under the Marathon legacy benefit formula is reduced in accordance with the table below:

Age at Retirement	Early Retirement Factor	Age at Retirement	Early Retirement Factor
62	100%	55	75%
61	97%	54	71%
60	94%	53	67%
59	91%	52	63%
58	87%	51	59%
57	83%	50	55%
56	79%		

There are no early retirement subsidies under the cash-balance formula. Of our NEOs providing a majority of their services to our business, only Ms. Beall has accrued a benefit under the Marathon legacy benefit formula. Ms. Beall is currently eligible for early retirement benefits under the Marathon legacy benefit formula.

Under the cash-balance formula, plan participants receive pay credits based on age and cash-balance service. For 2016, Ms. Beall received pay credits equal to 11 percent of compensation, which is the highest level of pay credit available under the plan. Mr. Templin received pay credits equal to nine percent of compensation. Mr. Bromley received pay credits equal to 11 percent of compensation and Mr. Floerke received pay credits equal to nine percent of compensation. Additionally, under the terms of his employment offer entered into with MPC's former parent company Marathon Oil Company, Mr. Templin receives additional contributions to the non-qualified plan to ensure that the aggregate contributions from the qualified and non-qualified retirement plans equal 11 percent of his applicable compensation. Based on the age and service calculation specified in the Marathon Petroleum Retirement Plan, Mr. Templin will receive a supplemental non-qualified contribution set at two percent of eligible compensation in the Marathon Petroleum Excess Benefit Plan. This supplemental contribution will be eliminated when Mr. Templin becomes eligible for the full 11 percent contribution under the qualified plan in 2022.

Marathon Petroleum Excess Benefit Plan (Defined Benefit)

Marathon Petroleum Company LP (or MPC LP) sponsors the Marathon Petroleum Excess Benefit Plan, an unfunded, non-qualified retirement plan, for the benefit of a select group of management and highly compensated employees. The Marathon Petroleum Excess Benefit Plan generally provides benefits that participants, including our NEOs, would have otherwise received under the tax-qualified Marathon Petroleum Retirement Plan were it not for Internal Revenue Code limitations. For our NEOs, eligible earnings under the Marathon Petroleum Excess Benefit Plan include the items listed above, excluding bonuses, for the Marathon Petroleum Retirement Plan, as well as deferred compensation contributions, for the highest consecutive 36-month period over the 10-year period up to December 31, 2012. The Marathon Petroleum Excess Benefit Plan also provides an enhancement for executive officers using the three highest bonuses earned over the 10-year period up to December 31, 2012, instead of the consecutive bonus formula in place for non-officers. MPC believes this enhancement is appropriate in light of the greater volatility of executive officer bonuses. However, as Messrs. Templin, Bromley and Floerke have not accrued a benefit under the Marathon legacy benefit formula, they are not eligible for this enhancement.

Marathon Petroleum Thrift Plan

MPC LP sponsors the Marathon Petroleum Thrift Plan, a tax-qualified employee savings plan. In general, all of MPC's employees, including our NEOs, are immediately eligible to participate in the Marathon Petroleum Thrift Plan. The purpose of the Marathon Petroleum Thrift Plan is to assist employees in maintaining a steady program of savings to supplement their retirement income and to meet other financial needs.

The Marathon Petroleum Thrift Plan allows contributions for NEOs on a pre-tax or Roth basis. Employees may elect to make any combination of pre-tax or Roth contributions from one percent to a maximum of 25 percent of gross pay. The participating employer will match participant contributions at a rate of 117 percent up to a maximum of six percent of gross pay. All matching contributions made on or after January 1, 2016, are fully vested.

Marathon Petroleum Excess Benefit Plan (Defined Contribution)

Certain highly compensated non-officer employees and, prior to January 1, 2006, executive officers who elected not to participate in the Marathon Petroleum Deferred Compensation Plan, comprise those eligible to receive defined contribution accruals under the Marathon Petroleum Excess Benefit Plan. The defined contribution formula in the Marathon Petroleum Excess Benefit Plan is designed to allow eligible employees to receive employer matching contributions equal to the amount they would have otherwise received under the tax-qualified Marathon Petroleum Thrift Plan were it not for Internal Revenue Code limitations.

Defined contribution accruals in the Marathon Petroleum Excess Benefit Plan are credited with interest equal to that paid in the "Marathon Stable Value Fund" option of the Marathon Petroleum Thrift Plan. The annual rate of return on this option for the year ended December 31, 2016, was 1.76 percent. All distributions from the plan are paid in the form of a lump sum following the participant's separation from service.

As noted, our NEOs no longer participate in the defined contribution formula of the Marathon Petroleum Excess Benefit Plan; all non-qualified employer matching contributions for our NEOs now accrue under the Marathon Petroleum Amended and Restated Deferred Compensation Plan.

Other Non-Qualified Deferred Compensation

The Non-Qualified Deferred Compensation Table below provides information regarding the non-qualified savings and deferred compensation plans sponsored by MPC or its subsidiaries.

2016 Non-Qualified Deferred Compensation

Name	Executive contributions in last fiscal year ($)	Registrant contributions in last fiscal year[(1)] ($)	Aggregate earnings in last fiscal year ($)	Aggregate withdrawals/ distributions ($)	Aggregate balance at last fiscal year-end ($)
Pamela K.M. Beall					
Marathon Petroleum Excess Benefit Plan	—	—	2,685.00	—	133,053.00
Marathon Petroleum Deferred Compensation Plan	—	55,877.00	30,135.00	—	725,976.00
Donald C. Templin					
Marathon Petroleum Deferred Compensation Plan	—	109,852.20	39,194.10	—	545,989.50
C. Corwin Bromley					
Marathon Petroleum Deferred Compensation Plan	—	39,061.00	3,105.00	—	42,166.00
Gregory S. Floerke					
Marathon Petroleum Deferred Compensation Plan	—	32,989.00	2,366.00	—	35,354.00

(1) The amounts shown in this column are also included in the "All Other Compensation" column of the 2016 Summary Compensation Table.

Marathon Petroleum Deferred Compensation Plan

MPC LP sponsors the Marathon Petroleum Amended and Restated Deferred Compensation Plan (which we refer to as the Marathon Petroleum Deferred Compensation Plan). The Marathon Petroleum Deferred Compensation Plan is an unfunded, non-qualified plan in which our NEOs may participate. This plan is designed to provide participants the opportunity to supplement their retirement savings by deferring income in a tax-effective manner. Participants may defer up to 20 percent of their salary and bonus each year. Deferral elections are made in December of each year for amounts to be earned in the following year and are irrevocable. The Marathon Petroleum Deferred Compensation Plan provides for a match on any participant's salary and bonus deferral equal to the percentage provided by the Marathon Petroleum Thrift Plan, which is currently 117 percent of contributions up to six percent of gross pay. Participants are fully vested in their deferrals under the plan.

In addition, the Marathon Petroleum Deferred Compensation Plan provides benefits for participants equal to the employer matching contributions they would have otherwise received under the tax-qualified Marathon Petroleum Thrift Plan were it not for Internal Revenue Code limitations. All matching contributions made on or after January 1, 2016, are fully vested.

The investment options available under the Marathon Petroleum Deferred Compensation Plan generally mirror the investment options offered to participants under the Marathon Petroleum Thrift Plan with the exception of MPC common stock and BrokerageLink, which are not investment options under the Marathon Petroleum Deferred Compensation Plan. The Marathon Petroleum Deferred Compensation Plan provides that all participants will receive their benefits as a lump sum following separation from service.

Section 409A Compliance

All of MPC's non-qualified deferred compensation plans in which our NEOs participate are in compliance with, or exempt from, Section 409A of the Internal Revenue Code. As a result, distribution of amounts subject to Section 409A may be delayed for six months following retirement or other separation from service where the participant is considered a "specified employee" for purposes of Section 409A.

Potential Payments Upon a Termination or Change In Control

The only situation in which an NEO would receive payment due to the accelerated vesting of our performance units and phantom units, without the discretion of the board of directors of our general partner, would be upon a termination from service in connection with the change in control of MPLX LP. The amount payable to each of our NEOs, assuming such termination occurred on December 31, 2016, based on our MPLX LP common unit closing price and MPC stock closing price as of that date and assuming our performance units settled at target, would have been as follows: Mr. Heminger, $4,181,060; Ms. Beall, $618,843; Mr. Bromley, $3,333,008; Mr. Floerke, $2,873,843; and Mr. Templin, $2,101,020.

COMPENSATION OF OUR DIRECTORS

The officers or employees of our general partner or of MPC who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. Directors of our general partner who are not officers or employees of our general partner or of MPC receive compensation as "non-management directors."

In October 2016, the board of directors of our general partner approved an increase to the non-management director compensation package. Effective January 1, 2017, each of our non-management directors receives a compensation package having an annual value equal to $175,000, instead of the prior $150,000, and payable as follows:

- 50 percent in the form of a cash retainer, payable in equal quarterly installments of $21,875 (at the commencement of each calendar quarter); and
- 50 percent in the form of a phantom unit award (granted at the commencement of each calendar quarter) representing a number of units having a value (based on the closing price of our common units on the date of grant) equal to $21,875. The phantom unit awards are not subject to any risk of forfeiture once granted and are automatically deferred until and settled in common units at the time the non-management director separates from service on the board or upon his or her death, if earlier.

In addition, the chair of each standing committee of the board and our lead director, who also serves on the executive committee of the board, each receive an additional annual retainer. These additional annual retainers are payable in cash (in equal quarterly installments at the commencement of each calendar quarter) as follows:

- Audit Committee Chair—$15,000;
- Conflicts Committee Chair—$15,000;
- Lead Director & Executive Committee Member—$15,000; and
- Other Committee Chair—$7,500.

Members of the conflicts committee will also receive a meeting fee in the amount of $1,500 per meeting for each conflicts committee meeting such member attends in a calendar year in excess of six meetings.

Further, each director is indemnified for his or her actions associated with being a director to the fullest extent permitted under Delaware law and is reimbursed for all expenses incurred in attending to his or her duties as a director.

2016 Director Compensation Table

Amounts reflected in the table below represent compensation earned by or paid to our general partner's non-employee directors for the year ended December 31, 2016.

Name	Fees Earned or Paid in Cash[1] ($)	Unit Awards[2] ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings ($)	All Other Compensation[3] ($)	Total ($)
Michael L. Beatty	75,000	75,000	—	—	—	—	150,000
David A. Daberko	75,000	75,000	—	—	—	—	150,000
Christopher A. Helms	90,000	75,000	—	—	—	10,000	175,000
Garry L. Peiffer	75,000	75,000	—	—	—	—	150,000
Dan D. Sandman	90,000	75,000	—	—	—	10,000	175,000
Frank M. Semple	12,432	12,432	—	—	—	—	24,864
John P. Surma	75,000	75,000	—	—	—	—	150,000
C. Richard Wilson	90,000	75,000	—	—	—	—	165,000

(1) The amounts shown in this column reflect the director cash retainers and committee chair and lead director fees paid for service from January 1, 2016, through December 31, 2016.

(2) The amounts shown in this column reflect the aggregate grant date fair value, as computed in accordance with provisions of Financial Accounting Standards Board Accounting Standards Codification 718, Compensation—Stock Compensation ("FASB ASC Topic 718"), for phantom unit awards granted to the non-management directors in 2016. All phantom unit awards are deferred until departure from the board and distribution equivalents in the form of additional phantom unit awards are credited to non-management director deferred accounts as and when distributions are paid on our common units. The aggregate number of MPLX LP phantom unit awards credited for board service and outstanding as of December 31, 2016, for each non-employee director is as follows: Messrs. Daberko, Helms, Sandman, Surma, and Wilson, 7,552; Mr. Peiffer, 5,077; Mr. Beatty, 2,563; and Mr. Semple, 366.

(3) The amounts shown in this column reflect contributions made on behalf of Messrs. Helms and Sandman to educational institutions under our matching gifts program.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Security Ownership of Certain Beneficial Owners

The following table sets forth information from filings made with the SEC as to each person or group who as of December 31, 2016 (unless otherwise noted) beneficially owned more than five percent of our outstanding units or more than five percent of any class of our outstanding units.

Name and Address of Beneficial Owner	Number of Common Units Representing Limited Partner Interests	Percent of Common Units Representing Limited Partner Interests	Number of General Partner Units	Percent of General Partner Units	Percent of Units Representing Total Partnership Interests(2)
Marathon Petroleum Corporation(1) 539 S. Main Street Findlay, Ohio 45840	86,619,313	24.2%	7,371,105	100%	25.5%
Tortoise Capital Advisors, L.L.C.(3) 11550 Ash Street, Suite 300 Leawood, Kansas 66211	18,894,274(3)	5.4%(3)	—	—	5.1%
ALPS Advisors, Inc.(4) 1290 Broadway, Suite 1100 Denver, Colorado 80203	18,146,214(4)	5.2%(4)	—	—	4.9%
Alerian MLP ETF(4) 1290 Broadway, Suite 1100 Denver, Colorado 80203	17,970,288(4)	5.2%(4)	—	—	4.9%

(1) The 86,619,313 common units representing limited partner interests ("Common Units") are directly held by MPLX Logistics Holdings LLC and MPLX Holdings Inc. The 7,371,105 general partner units are directly held by MPLX GP LLC and represent its two percent general partner interest in MPLX LP. Marathon Petroleum Corporation is the ultimate parent company of MPLX GP LLC, MPLX Logistics Holdings LLC and MPLX Holdings Inc. and may be deemed to beneficially own the Common Units directly held by MPLX Logistics Holdings LLC and MPLX Holdings Inc., and the general partner units directly owned by MPLX GP LLC. MPC Investment LLC owns all of the membership interests in or shares of MPLX GP LLC, MPLX Logistics Holdings LLC and MPLX Holdings Inc., and MPC owns all of the membership interest in MPC Investment LLC.

(2) Percentages were calculated including the Class B units on an as-converted basis. All of the 3,990,878 Class B units currently outstanding are owned by M&R MWE Liberty LLC and will convert into approximately 4.4 million Common Units on July 1, 2017.

(3) According to a Schedule 13G/A filed with the SEC on February 14, 2017, by Tortoise Capital Advisors, L.L.C. ("TCA"). According to such Schedule 13G/A, TCA acts as an investment adviser to certain investment companies registered under the Investment Company Act of 1940. TCA, by virtue of investment advisory agreements with these investment companies, has all investment and voting power over securities owned of record by these investment companies. However, despite their delegation of investment and voting power to TCA, these investment companies may be deemed to be the beneficial owners under Rule 13d-3 of the Act, of the securities they own of record because they have the right to acquire investment and voting power through termination of their investment advisory agreement with TCA. Thus, TCA has reported that it shares voting power and dispositive power over the securities owned of record by these investment companies. TCA also acts as an investment adviser to certain managed accounts. Under contractual agreements with these managed account clients, TCA, with respect to the securities held in these client accounts, has investment and voting power with respect to certain of these client accounts, and has

investment power but no voting power with respect to certain other of these client accounts. TCA has reported that it shares voting and/or investment power over the securities held by these client managed accounts despite a delegation of voting and/or investment power to TCA because the clients have the right to acquire investment and voting power through termination of their agreements with TCA. TCA may be deemed the beneficial owner of the securities covered by this statement under Rule 13d-3 of the Act that are held by its clients. Subject to the above, TCA reported that it has beneficial ownership of 18,894,274 Common Units or 5.4% of the Common Units outstanding, sole voting power over 344,682 of our Common Units, shared voting power over 16,345,231 of our Common Units, sole dispositive power over 344,682 of our Common Units and shared dispositive power over 18,549,592 of our Common Units.

(4) According to a Schedule 13G/A filed with the SEC on January 26, 2017, by ALPS Advisors, Inc. ("AAI") and Alerian MLP ETF. According to such Schedule 13G/A, AAI, an investment adviser registered under Section 203 of the Investment Advisors Act of 1940, furnishes investment advice to investment companies registered under the Investment Company Act of 1940 (collectively referred to as the "Funds"). In its role as investment advisor, AAI has voting and/or investment power over the securities of the Issuer that are owned by the Funds, and may be deemed to be the beneficial owner of the shares of the Issuer held by the Funds. However, all securities reported in this schedule are owned by the Funds. AAI disclaims beneficial ownership of such securities. In addition, the filing of this Schedule 13G/A shall not be construed as an admission that the reporting person or any of its affiliates is the beneficial owner of any securities covered by this Schedule 13G/A for any other purposes than Section 13(d) of the Securities Exchange Act of 1934. Alerian MLP ETF is an investment company registered under the Investment Company Act of 1940 and is one of the Funds to which AAI provides investment advice. Subject to the above, AAI reported that it has beneficial ownership of 18,146,214 Common Units or 5.21% of the Common Units outstanding, sole voting power over none of our Common Units, shared voting power over 18,146,214 of our Common Units, sole dispositive power over none of our Common Units and shared dispositive power over 18,146,214 of our Common Units. Subject to the above, and according to the Schedule 13G/A, Alerian MLP ETF reported that it has beneficial ownership of 17,970,288 Common Units or 5.16% of the Common Units outstanding, sole voting power over none of our Common Units, shared voting power over 17,970,288 of our Common Units, sole dispositive power over none of our Common Units and shared dispositive power over 17,970,288 of our Common Units.

Security Ownership of Directors and Executive Officers

The following table sets forth the number of MPLX LP common units beneficially owned as of January 31, 2017, except as otherwise noted, by each director of our general partner, by each named executive officer of our general partner and by all directors and executive officers of our general partner as a group. The address for each person named below is c/o MPLX LP, 200 East Hardin Street, Findlay, Ohio 45840.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership(1)	Percent of Total Outstanding
Directors / Named Executive Officers		
Gary R. Heminger	174,753(2)(5)(6)(7)	*
Pamela K.M. Beall	21,892(2)(5)(7)	*
Michael L. Beatty	30,554(2)(4)	*
C. Corwin Bromley	118,314(2)(5)	*
Nancy K. Buese	76,830(2)(5)	*
David A. Daberko	19,843(2)(3)(4)	*
Gregory S. Floerke	77,181(2)(5)	*
Timothy T. Griffith	18,302(2)(5)(7)	*
Christopher A. Helms	19,173(2)(4)	*
Garry L. Peiffer	37,395(4)(6)	*
Dan D. Sandman	52,173(2)(4)	*
Frank M. Semple	577,461(2)(3)(4)(6)	*
John P. Surma	17,343(2)(3)(4)	*
Donald C. Templin	57,409(2)(5)(7)	*
C. Richard Wilson	18,173(2)(4)	*
All Directors and Executive Officers as a group (18 reporting persons)	1,553,318(2)(3)(4)(5)(6)(7)	*

(1) None of the common units reported in this column are pledged as security.

(2) Includes common units directly or indirectly held in beneficial form.

(3) Includes phantom unit awards granted pursuant to the MPLX LP 2012 Incentive Compensation Plan and credited within a deferred account pursuant to the Marathon Petroleum Corporation Deferred Compensation Plan for Non-Employee Directors. The aggregate number of phantom unit awards credited as of January 31, 2017, for each of Messrs. Daberko and Surma is 1,670; and Mr. Semple 180.

(4) Includes phantom unit awards granted pursuant to the MPLX LP 2012 Incentive Compensation Plan and credited within a deferred account pursuant to the MPLX GP LLC Non-Management Director Compensation Policy and Director Equity Award Terms. The aggregate number of phantom unit awards credited as of January 31, 2017, for the non-management directors of our general partner is as follows: Messrs. Daberko, Helms, Sandman, Surma and Wilson, 8,173 each; Mr. Beatty, 3,184; Mr. Peiffer, 5,698; and Mr. Semple, 987.

(5) Includes phantom unit awards granted pursuant to the MPLX LP 2012 Incentive Compensation Plan, which may be forfeited under certain conditions.

(6) Includes common units indirectly beneficially owned in trust. The number of common units held in trust as of January 31, 2017, by each applicable director or named executive officer of our general partner is as follows: Mr. Heminger, 26,750; Mr. Peiffer, 31,697; and Mr. Semple, 527,517.

(7) Includes common units issued in settlement of performance units within sixty days of January 31, 2017.

* The percentage of common units beneficially owned by each director or each executive officer of our general partner does not exceed one percent of the common units outstanding, and the percentage of common units beneficially owned by all directors and executive officers of our general partner as a group does not exceed one percent of the common units outstanding.

The following table sets forth the number of shares of MPC common stock beneficially owned as of January 31, 2017, except as otherwise noted, by each director of our general partner, by each named executive officer of our general partner and by all directors and executive officers of our general partner as a group. The address for each person named below is c/o MPLX LP, 200 East Hardin Street, Findlay, Ohio 45840.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership[1]	Percent of Total Outstanding
Directors/Named Executive Officers		
Gary R. Heminger	2,589,729[2][5][6][8][9][10]	*
Pamela K.M. Beall	138,293[2][5][9][10]	*
Michael L. Beatty	—	*
C. Corwin Bromley	19,861[5]	*
Nancy K. Buese	—	*
David A. Daberko	144,998[2][3]	*
Gregory S. Floerke	19,950[5][6]	*
Timothy T. Griffith	160,261[2][5][9][10]	*
Christopher A. Helms	—	*
Garry L. Peiffer	277,084[8][9]	*
Dan D. Sandman	—	*
Frank M. Semple	1,170[3]	*
John P. Surma	37,375[3][8]	*
Donald C. Templin	482,296[2][5][9][10]	*
C. Richard Wilson	—	*
All Directors and Executive Officers as a group (18 reporting persons)	4,161,343[2][3][4][5][6][7][8][9][10]	*

(1) None of the shares of common stock reported in this column are pledged as security.

(2) Includes shares of common stock directly or indirectly held in registered or beneficial form.

(3) Includes restricted stock unit awards granted pursuant to the Second Amended and Restated Marathon Petroleum Corporation 2011 Incentive Compensation Plan and/or the Marathon Petroleum Corporation 2012 Incentive Compensation Plan, and credited within a deferred account pursuant to the Marathon Petroleum Corporation Deferred Compensation Plan for Non-Employee Directors. The aggregate number of restricted stock unit awards credited as of January 31, 2017, is as follows: Mr. Daberko, 140,998; Mr. Semple, 1,170; and Mr. Surma, 27,375.

(4) Includes restricted stock unit awards granted pursuant to the Marathon Petroleum Corporation 2012 Incentive Compensation Plan, a portion of which may be forfeited under certain conditions.

(5) Includes shares of restricted stock issued pursuant to the Marathon Petroleum Corporation 2012 Incentive Compensation Plan, which are subject to limits on sale and transfer, and may be forfeited under certain conditions.

(6) Includes shares of common stock held within the Marathon Petroleum Thrift Plan.

(7) Includes shares of common stock held within the Marathon Petroleum Corporation Dividend Reinvestment and Direct Stock Purchase Plan.

(8) Includes shares of common stock indirectly beneficially owned in trust. The number of shares held in trust as of January 31, 2017, by each applicable director or named executive officer of our general partner is as follows: Mr. Heminger, 21,228; Mr. Peiffer, 63,394; and Mr. Surma, 10,000.

(9) Includes stock options exercisable within sixty days of January 31, 2017, including 255,210 stock options exercisable by the applicable directors and named executive officers but not in the money as of January 31, 2017.

(10) Includes shares of common stock issued in settlement of performance units within sixty days of January 31, 2017.

* The percentage of shares beneficially owned by each director or each executive officer of our general partner does not exceed one percent of the MPC common shares outstanding, and the percentage of shares beneficially owned by all directors and executive officers of our general partner as a group does not exceed one percent of the MPC common shares outstanding.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2016, with respect to common units that may be issued under the MPLX LP 2012 Incentive Compensation Plan:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[(1)]	Weighted average exercise price of outstanding options, warrants and rights[(2)]	Number of securities remaining available for future issuance under equity compensation plans[(3)]
Equity compensation plans approved by security holders	1,277,354	N/A	1,229,440
Equity compensation plans not approved by security holders	—	—	—
Total	1,277,354		1,229,440

(1) Includes the following:
(a) 1,173,411 phantom unit awards granted pursuant to the MPLX 2012 Plan for common units unissued and not forfeited, cancelled or expired as of December 31, 2016.
(b) 103,943 units as the maximum potential number of common units that could be issued in settlement of performance units outstanding as of December 31, 2016, pursuant to the MPLX 2012 Plan based on the closing price of our common units on December 31, 2016, of $34.62 per unit. The number of units reported for this award vehicle may overstate dilution. See Item 8. Financial Statements and Supplementary Data—Note 20 for more information on performance unit awards granted under the MPLX 2012 Plan.

(2) There is no exercise price associated with phantom unit awards.

(3) Reflects the common units available for issuance pursuant to the MPLX 2012 Plan. The number of units reported in this column assumes 103,943 as the maximum potential number of common units that could be issued in settlement of performance units outstanding as of December 31, 2016, pursuant to the MPLX 2012 Plan based on the closing price of our common units on December 31, 2016, of $34.62 per unit. The number of units assumed for this award vehicle may understate the number of common units available for issuance pursuant to the MPLX 2012 Plan. See Item 8. Financial Statements and Supplementary Data—Note 20 for more information on performance unit awards issued pursuant to the MPLX 2012 Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Certain Relationships and Related Party Transactions

Our general partner is an affiliate of MPC. On March 14, 2016, the Partnership entered into a Membership Interests Contribution Agreement (the "Contribution Agreement") with MPLX GP, MPLX Logistics Holdings LLC and MPC Investment LLC ("MPC Investment"), each a wholly-owned subsidiary of MPC, related to the acquisition of HSM, MPC's inland marine business, from MPC. Pursuant to the Contribution Agreement, the transaction was valued at $600 million consisting of a fixed number of common units and general partner units. The general partner units maintained MPC's two percent general partner interest in the Partnership. The acquisition closed on March 31, 2016. MPC waived distributions in the first quarter of 2016 on MPLX LP common units issued in connection with this transaction. See Item 8. Financial Statements and Supplementary Data—Note 4 for more information on this transaction.

On September 1, 2016, the Partnership and various affiliates initiated a series of reorganization transactions in order to simplify the Partnership's ownership structure and its financial and tax reporting requirements (the "Class A Reorganization"). In connection with these transactions, all of the issued and outstanding MPLX LP Class A units, all of which were held by MarkWest Hydrocarbon (MarkWest Hydrocarbon, Inc. prior to the

Class A Reorganization), were either distributed to or purchased by MPC in exchange for $84 million in cash and a fixed number of MPLX LP common units and MPLX LP general partner units. Following these preparatory transactions, all of the MPLX LP Class A units were exchanged on a one-for-one basis for newly issued common units representing limited partner interests in MPLX LP. MPC also contributed $141 million to facilitate the repayment of intercompany debt between MarkWest Hydrocarbon and MarkWest. As a result of these transactions, the MPLX LP Class A units were eliminated, are no longer outstanding and no longer participate in distributions of cash from the Partnership. Cash that is derived from or attributable to MarkWest Hydrocarbon's operations is now treated in the same manner as cash derived from or attributable to other operations of the Partnership and its subsidiaries. See Item 8. Financial Statements and Supplementary Data—Note 8 for more information on this transaction.

As of February 13, 2017, MPC owned 86,619,313 common units. In addition, our general partner owned 7,372,419 general partner units as well as all of our incentive distribution rights. Our general partner manages our operations and activities through its officers and directors. Messrs. Heminger, Templin, Nickerson and Swearingen serve as executive officers of our general partner and MPC. Accordingly, we view transactions between us and MPC as related party transactions.

Distributions by the Partnership

Pursuant to our third amended and restated agreement of limited partnership, we make cash distributions to our unitholders, including MPC as the direct and indirect holder of common units, as well as a two percent general partner interest. If distributions exceed the minimum quarterly distribution and target distribution levels, the general partner is entitled to increasing percentages of our distributions, up to 48 percent of our distributions above the highest target distribution level. In 2016, we paid MPC $142 million in cash distributions with respect to its common units, and $190 million in cash distributions with respect to its two percent general partner interest.

Reimbursements paid to MPC

Pursuant to our third amended and restated agreement of limited partnership, we are required to reimburse our general partner and its affiliates, including MPC, for all costs and expenses that our general partner and its affiliates, including MPC, incur on our behalf for managing and controlling our business and operations. Except to the extent specified under the omnibus agreement (described below), our general partner determines the amount of these expenses and such determinations are required to be made in good faith in accordance with the terms of our third amended and restated agreement of limited partnership. In 2016, we reimbursed our general partner $7 million for costs and expenses incurred on our behalf.

Transportation and Storage Services Agreements

We are a party to long-term, fee-based transportation and storage services agreements with MPC. Under these agreements, we provide transportation and storage services to MPC, and MPC provides us with minimum quarterly throughput and storage volumes of crude oil and products and minimum storage volumes of butane. These commercial agreements with MPC are described in more detail under Item 1. Business—Our Transportation and Storage Services Agreements with MPC and Item 8. Financial Statements and Supplementary Data—Note 6. We recorded aggregate revenues of $717 million for 2016 under these transportation and storage services agreements.

Operating Service Agreements

We are a party to an operating services agreement with MPC, under which we operate various pipeline systems owned by MPC. In addition, MPC is a party to operating services agreements with Marathon Pipe Line LLC (or MPL), a wholly-owned subsidiary of Pipe Line Holdings. MPL operates various pipeline systems owned by

MPC. Under these operating services agreements, we receive an operating fee for operating the assets and are reimbursed for all direct and indirect costs associated with operating the assets. Most of these agreements are indexed for inflation. These agreements have terms ranging from one to five years and automatically renew unless terminated by either party. The operating service agreements are described in Item 1. Business—Operating and Management Services Agreements with MPC and Third Parties and Item 8. Financial Statements and Supplementary Data—Note 6. We recorded other income of $22 million and were reimbursed for $17 million of costs and expenses for 2016 under these operating services agreements.

Management Services Agreements

We are a party to two management services agreements with MPC, under which we provide certain management services to MPC with respect to certain of MPC's retained pipeline assets. MPC pays us a fixed annual fee under the agreements for providing the management services, as adjusted for inflation and changes in the scope of management services provided. These management services agreements are described in more detail under Item 1. Business—Operating and Management Services Agreements with MPC and Third Parties, and Item 8. Financial Statements and Supplementary Data—Note 6. We recorded other income of $22 million in fees for 2016 under these management services agreements.

Omnibus Agreement

We are a party to an omnibus agreement with MPC, under which we pay a fixed annual fee to MPC for the provision by MPC of executive management services by certain executive officers of our general partner, as well as certain general and administrative services and marketing and transportation engineering services. The omnibus agreement also requires us to reimburse MPC for any out-of-pocket costs and expenses incurred by MPC in providing these services. Also under the omnibus agreement, MPC has agreed to indemnify us for certain matters, including environmental, title and tax matters. The omnibus agreement is described in more detail under Item 1. Business—Other Agreements with MPC and Item 8. Financial Statements and Supplementary Data—Note 6. We incurred service fees and expenses of $63 million under the omnibus agreement for 2016.

Employee Services Agreements

We are a party to four employee services agreements with MPC, under which we reimburse MPC for the provision of certain operational and management services in support of our facilities. The employee services agreements are described in more detail under Item 1. Business—Other Agreements with MPC and Item 8. Financial Statements and Supplementary Data—Note 6. We incurred aggregate expenses of $359 million under the employee services agreements for 2016.

Licensing Agreement

MPL and MPC are parties to a license agreement with respect to a terminal property leased by MPL, pursuant to which MPC has access to and operates the terminal. The agreement will remain in effect until February 1, 2020. We recorded other income of $1 million in 2016 related to this agreement.

Loan Agreement

On December 4, 2015, the Partnership entered into a loan agreement with MPC Investment, a wholly owned subsidiary of MPC. Under the terms of the agreement, MPC Investment will make a loan or loans to the Partnership on a revolving basis as requested by the Partnership and as agreed to by MPC Investment, in an amount or amounts that do not result in the aggregate principal amount of all loans outstanding exceeding $500 million at any one time. The entire unpaid principal amount of the loan, together with all accrued and unpaid interest and other amounts (if any), will become due and payable on December 4, 2020. MPC Investment may demand payment of all or any portion of the outstanding principal amount of the loan, together with all accrued and unpaid interest and other amounts (if any), at any time prior to December 4, 2020. Borrowings under the loan will bear interest at LIBOR plus 1.50 percent. There was no outstanding balance on this loan as of December 31, 2016.

Other Sales to MPC

We recorded aggregate revenues of $11 million in 2016 related to certain products MPC purchased from the Partnership. For 2016, there was $46 million of additional product sales to MPC that net to zero within the consolidated financial statements, as the transactions are recorded net due to the terms of the agreements under which such product was sold.

Time Sharing Agreement

We are a party to a time sharing agreement with MPC, under which we use certain aircraft leased and operated by MPC. Under this agreement, we reimburse MPC for the costs associated with leasing and operating the aircraft based on our actual use of the aircraft. The agreement will remain in effect until terminated by either party. We incurred expenses of less than $1 million under the time sharing agreement for 2016.

Procedures for Review, Approval and Ratification of Related Person Transactions

The board of directors of our general partner has adopted a formal written related person transactions policy. Under the policy, a “related person” includes any director, nominee for director, executive officer, or a known beneficial holder of more than five percent of any class of the Partnership’s voting securities (other than MPC or its affiliates) or any immediate family member of a director, nominee for director or executive officer or more than five percent owner. This procedure applies to any transaction, arrangement or relationship or any series of similar transactions, arrangements or relationships in which we are a participant and the amount involved exceeds $120,000 and in which a related person has a direct or indirect interest; provided that the following transactions, arrangements or relationships will be deemed to have standing pre-clearance of the board of directors:

- Payment of compensation to an executive officer or director of our general partner if the compensation is otherwise required to be disclosed in our filings with the SEC;
- Any transaction where the related person’s interest arising solely from the ownership of securities;
- Any ongoing employment relationship provided that such employment relationship will be subject to initial review and approval; and
- Any transaction between the Partnership or any of its subsidiaries, on the one hand, and our general partner or any of its affiliates, on the other hand; provided, however, that such transaction is approved consistent with our partnership agreement.

Any related person transaction that is identified prior to its consummation will be consummated only if approved by the board of directors of our general partner prior to its consummation. If the related person transaction is identified after it commences, it will be promptly submitted to the board of directors of our general partner or the chairman for ratification, amendment or rescission. If the transaction has been completed, the board of directors of our general partner or the chairman will evaluate the transaction to determine if rescission is appropriate.

In determining whether to approve or ratify a related person transaction, the board of directors of our general partner or the chairman will consider all relevant facts and circumstances, including but not limited to:

- the benefits to the Partnership, including the business justification;

- the impact on a director's independence in the event the related person is a director or an immediate family member of a director;
- the availability of other sources for comparable products or services;
- the terms of the transaction and the terms available to unrelated third parties or to employees generally; and
- whether or not the transaction is consistent with our Code of Business Conduct.

The related person transactions policy described above was adopted after the closing of the Initial Offering and, as a result, the transactions and arrangements with MPC described above that were entered into prior to the closing of the Initial Offering were not reviewed under such policy, but were approved by the board of directors of our general partner.

Director Independence

The information appearing under Item 10. Directors, Executive Officers and Corporate Governance—Director Independence, is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Aggregate fees for professional services rendered for the Partnership by PricewaterhouseCoopers LLP for the years ended December 31, 2016, and December 31, 2015, are presented in the following table:

Fees[1] *(In millions)*	2016	2015
Audit	$ 4	$ 4
Audit-Related	—	—
Tax	1	1
All Other	—	—
Total	$ 5	$ 5

(1) The Partnership's Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services Policy is summarized in this Annual Report on Form 10-K. See "Audit Committee Policy for Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services." In 2016 and 2015, all of these services were pre-approved by the Audit Committee of our general partner in accordance with its pre-approval policy. Our Audit Committee did not utilize the Policy's de minimis exception in 2016 or 2015.

The Audit fees for the years ended December 31, 2016, and December 31, 2015, were for professional services rendered for the audit of the financial statements and of internal controls over financial reporting, the performance of regulatory audits, issuance of comfort letters, the provision of consents and the review of documents filed with the SEC.

The Tax fees for the year ended December 31, 2016, and December 31, 2015, were for professional services rendered for the preparation of IRS Schedule K-1 tax forms for MPLX LP unit holders and for income tax consultation services.

The Audit Committee of MPLX GP LLC has considered whether PricewaterhouseCoopers LLP is independent for purposes of providing external audit services to the Partnership and has determined that it is.

Audit Committee Policy for Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services

Among other things, our Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services Policy sets forth the procedure for the Audit Committee to pre-approve all audit, audit-related, tax and permissible non-audit services, other than as provided under a de minimis exception.

Under the policy, the Audit Committee may pre-approve any services to be performed by our independent auditor up to twelve months in advance and may approve in advance services by specific categories pursuant to a forecasted budget. Annually, the executive vice president and chief financial officer of our general partner will present a forecast of audit, audit-related, tax and permissible non-audit services for the ensuing fiscal year to the Audit Committee for approval in advance. The executive vice president and chief financial officer of our general partner, in coordination with the independent auditor, will provide an updated budget to the Audit Committee, as needed, throughout the ensuing fiscal year.

Pursuant to the policy, the Audit Committee has delegated pre-approval authority of up to $250,000 to the Chair of the Audit Committee for unbudgeted items, and the Chair reports the items pre-approved pursuant to this delegation to the full Audit Committee at the next scheduled meeting.

Part IV

Item 15. Exhibits and Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements (see Part II, Item 8. of this Annual Report on Form 10-K regarding financial statements)

2. Financial Statement Schedules

Financial statement schedules required under SEC rules but not included in this Annual Report on Form 10-K are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

Exhibits:

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
2.1	Partnership Interests Purchase Agreement dated February 26, 2014, by and between MPLX Operations LLC and MPL Investment LLC	8-K	2.1	3/4/2014	001-35714		
2.2	Partnership Interests Purchase and Contribution Agreement, dated December 1, 2014, by and among MPLX Operations LLC, MPLX Logistics Holdings LLC, MPLX LP and MPL Investment LLC	8-K	2.1	12/2/2014	001-35714		
2.3†	Agreement and Plan of Merger, dated as of July 11, 2015, by and among MPLX LP, Sapphire Holdco LLC, MPLX GP LLC, MarkWest Energy Partners, L.P. and, for certain limited purposes set forth therein, Marathon Petroleum Corporation	10-Q	2.1	8/3/2015	001-35714		
2.4	Amendment to Agreement and Plan of Merger, dated as of November 10, 2015, by and among MPLX LP, Sapphire Holdco LLC, MPLX GP LLC, MarkWest Energy Partners, L.P. and Marathon Petroleum Corporation	8-K	2.1	11/12/2015	001-35714		
2.5	Amendment Number 2 to Agreement and Plan of Merger, dated as of November 16, 2015, by and among MPLX LP, Sapphire Holdco LLC, MPLX GP LLC, MarkWest Energy Partners, L.P. and Marathon Petroleum Corporation	8-K	2.1	11/17/2015	001-35714		
2.6	Membership Interests Contribution Agreement, dated March 14, 2016, between MPLX LP, MPLX Logistics Holdings LLC, MPLX GP LLC and MPC Investment LLC	8-K	2.1	3/17/2016	001-35714		
3.1	Certificate of Limited Partnership of MPLX LP	S-1	3.1	7/2/2012	333-182500		
3.2	Amendment to the Certificate of Limited Partnership of MPLX LP	S-1/A	3.2	10/9/2012	333-182500		
3.3	Third Amended and Restated Agreement of Limited Partnership of MPLX LP, dated as of October 31, 2016	10-Q	3.3	10/31/2016	001-35714		
3.4	First Amendment to Third Amended and Restated Agreement of Limited Partnership of MPLX LP, dated as of February 23, 2017					X	
4.1	Indenture, dated February 12, 2015, between MPLX LP and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.1	2/12/2015	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
4.2	First Supplemental Indenture, dated February 12, 2015, between MPLX LP and The Bank of New York Mellon Trust Company, N.A., as Trustee (including Form of Notes)	8-K	4.2	2/12/2015	001-35714		
4.3	Registration Rights Agreement dated as of December 22, 2015 by and among MPLX LP, MPLX GP LLC, and each of Citigroup Global Markets Inc., J.P. Morgan Securities LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated	8-K	4.1	12/22/2015	001-35714		
4.4	Second Supplemental Indenture, dated as of December 22, 2015, by and between MPLX LP and the Bank of New York Mellon Trust Company, N.A. (including Form of Note)	8-K	4.2	12/22/2015	001-35714		
4.5	Third Supplemental Indenture, dated as of December 22, 2015, by and between MPLX LP and the Bank of New York Mellon Trust Company, N.A. (including Form of Note)	8-K	4.3	12/22/2015	001-35714		
4.6	Fourth Supplemental Indenture, dated as of December 22, 2015, by and between MPLX LP and the Bank of New York Mellon Trust Company, N.A. (including Form of Note)	8-K	4.4	12/22/2015	001-35714		
4.7	Fifth Supplemental Indenture, dated as of December 22, 2015, by and between MPLX LP and the Bank of New York Mellon Trust Company, N.A. (including Form of Note)	8-K	4.5	12/22/2015	001-35714		
4.8	Registration Rights Agreement, dated as of May 13, 2016, by and between MPLX LP and the Purchasers party thereto	8-K	4.1	5/16/2016	001-35714		
4.9	Sixth Supplemental Indenture, dated as of February 10, 2017, between the Issuer and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.1	2/10/2017	001-35714		
4.10	Seventh Supplemental Indenture, dated as of February 10, 2017, between the Issuer and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.2	2/10/2017	001-35714		
10.1	Credit Agreement, dated as of November 20, 2014, among MPLX LP, as borrower, Citibank, N.A., as administrative agent, each of Citigroup Global Markets Inc., Wells Fargo Securities, LLC, Barclays Bank PLC, J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporate and RBS Securities Inc., as joint lead arrangers and joint bookrunners, Wells Fargo Bank, N.A., as	8-K	10.1	11/26/2014	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
	syndication agent, and each of Bank of America, N.A., Barclays Bank PLC, JPMorgan Chase Bank, N.A., and The Royal Bank of Scotland PLC, as documentation agents, and the other lenders and issuing banks that are parties thereto						
10.2*	MPLX LP 2012 Incentive Compensation Plan	S-1/A	10.3	10/9/2012	333-182500		
10.3	Contribution, Conveyance and Assumption Agreement, dated as of October 31, 2012, among MPLX LP, MPLX GP LLC, MPLX Operations LLC, MPC Investment LLC, MPLX Logistics Holdings LLC, Marathon Pipe Line LLC, MPL Investment LLC, MPLX Pipe Line Holdings LP and Ohio River Pipe Line LLC	8-K	10.1	11/6/2012	001-35714		
10.4	Omnibus Agreement, dated as of October 31, 2012, among Marathon Petroleum Corporation, Marathon Petroleum Company LP, MPL Investment LLC, MPLX Operations LLC, MPLX Terminal and Storage LLC, MPLX Pipe Line Holdings LP, Marathon Pipe Line LLC, Ohio River Pipe Line LLC, MPLX LP and MPLX GP LLC	8-K	10.2	11/6/2012	001-35714		
10.5	Employee Services Agreement, dated effective as of October 1, 2012, by and among Marathon Petroleum Logistics Services LLC, MPLX GP LLC and Marathon Pipe Line LLC	S-1/A	10.6	10/9/2012	333-182500		
10.6	Employee Services Agreement, dated effective as of October 1, 2012, by and among Catlettsburg Refining LLC, MPLX GP LLC and MPLX Terminal and Storage LLC	S-1/A	10.7	10/9/2012	333-182500		
10.7	Management Services Agreement, dated effective as of September 1, 2012, by and between Hardin Street Holdings LLC and Marathon Pipe Line LLC	S-1/A	10.8	9/7/2012	333-182500		
10.8	Management Services Agreement, dated effective as of October 10, 2012, by and between MPL Louisiana Holdings LLC and Marathon Pipe Line LLC	S-1/A	10.9	10/18/2012	333-182500		
10.9	Amended and Restated Operating Agreement, dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.3	11/6/2012	001-35714		
10.10	Storage Services Agreement, dated effective as of October 1, 2012, by and between Marathon Pipe Line LLC and Marathon Petroleum Company LP (Patoka tank farm)	S-1/A	10.13	10/9/2012	333-182500		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
10.11	Storage Services Agreement, dated effective as of October 1, 2012, by and between Marathon Pipe Line LLC and Marathon Petroleum Company LP (Martinsville tank farm)	S-1/A	10.14	10/9/2012	333-182500		
10.12	Storage Services Agreement, dated effective as of October 1, 2012, by and between Marathon Pipe Line LLC and Marathon Petroleum Company LP (Lebanon tank farm)	S-1/A	10.15	10/9/2012	333-182500		
10.13	Storage Services Agreement, dated effective as of October 1, 2012, by and between Marathon Pipe Line LLC and Marathon Petroleum Company LP (Wood River tank farm)	S-1/A	10.16	10/9/2012	333-182500		
10.14	Storage Services Agreement, dated effective as of October 1, 2012, by and between MPLX Terminal and Storage LLC and Marathon Petroleum Company LP (Neal butane cavern)	S-1/A	10.17	10/9/2012	333-182500		
10.15	Transportation Services Agreement (Patoka to Lima Crude System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.4	11/6/2012	001-35714		
10.16	Transportation Services Agreement (Catlettsburg and Robinson Crude System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.5	11/6/2012	001-35714		
10.17	Transportation Services Agreement (Detroit Crude System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.6	11/6/2012	001-35714		
10.18	Transportation Services Agreement (Wood River to Patoka Crude System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.7	11/6/2012	001-35714		
10.19	Transportation Services Agreement (Garyville Products System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.8	11/6/2012	001-35714		
10.20	Transportation Services Agreement (Texas City Products System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.9	11/6/2012	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
10.21	Transportation Services Agreement (ORPL Products System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Ohio River Pipe Line LLC	8-K	10.10	11/6/2012	001-35714		
10.22	Transportation Services Agreement (Robinson Products System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.11	11/6/2012	001-35714		
10.23	Transportation Services Agreement (Wood River Barge Dock), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.12	11/6/2012	001-35714		
10.24*	MPC Non-Employee Director Phantom Unit Award Policy	10-K	10.26	3/25/2013	001-35714		
10.25*	Form of MPLX LP Phantom Unit Award Agreement—Officer	10-Q	10.1	5/9/2013	001-35714		
10.26*	Form of MPLX LP Performance Unit Award Agreement—2013-2015 Performance Cycle	10-Q	10.2	5/9/2013	001-35714		
10.27*	MPLX LP—Form of MPC Officer Phantom Unit Agreement	10-Q	10.3	5/9/2013	001-35714		
10.28*	MPLX LP—Form of MPC Officer Performance Unit Award Agreement—2013-2015 Performance Cycle	10-Q	10.4	5/9/2013	001-35714		
10.29*	Amendment to Outstanding Phantom Unit Award Agreement of Garry L. Peiffer dated November 18, 2013	10-K	10.31	2/28/2014	001-35714		
10.30*	MPLX GP LLC Amended and Restated Non-Management Director Compensation Policy and Equity Award Terms					X	
10.31	First Amendment to Amended and Restated Operating Agreement, dated as of January 1, 2015, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	10-Q	10.2	5/4/2015	001-35714		
10.32	Operating Agreement, dated as of January 1, 2015, between Hardin Street Transportation LLC and Marathon Pipe Line LLC	10-Q	10.3	5/4/2015	001-35714		
10.33	Lock-Up Agreement, dated July 11, 2015, by and among MPLX LP, MPLX GP LLC, Sapphire Holdco LLC, MarkWest Energy Partners, L.P., M&R MWE Liberty, LLC, EMG Utica, LLC and EMG Utica Condensate, LLC	10-Q	10.2	8/3/2015	001-35714		
10.34	Transportation Services Agreement (Cornerstone Pipeline System and Utica Build-Out Projects), effective as of June 11, 2015, by and between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.1	6/17/2015	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.35	First Amendment to Storage Services Agreement, dated as of September 17, 2015, by and between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.1	9/23/2015	001-35714		
10.36	Amendment Agreement, dated as of October 27, 2015, by and among MPLX LP, Citibank, N.A., Wells Fargo Bank, National Association, and the other institutions named on the signature pages thereto	8-K	10.1	11/2/2015	001-35714		
10.37	Loan Agreement, by and between MPLX LP and MPC Investment LLC, dated December 4, 2015	8-K	10.1	12/10/2015	001-35714		
10.38*	Retention Agreement, by and between Marathon Petroleum Company LP and Nancy K. Buese, dated September 14, 2015	8-K	10.2	12/10/2015	001-35714		
10.39*	Retention Agreement, by and between Marathon Petroleum Company LP and John C. Mollenkopf, dated November 12, 2015	8-K	10.3	12/10/2015	001-35714		
10.40*	Letter Agreement, by and between Marathon Petroleum Corporation and Paula L. Rosson, dated October 6, 2015	8-K	10.4	12/10/2015	001-35714		
10.41*	Retention Agreement, by and between Marathon Petroleum Company LP and Greg S. Floerke, dated September 14, 2015	10-K	10.41	2/26/2016	001-35714		
10.42*	Retention Agreement, by and between Marathon Petroleum Company LP and C. Corwin Bromley, dated September 14, 2015	10-K	10.42	2/26/2016	001-35714		
10.43	Employee Services Agreement, dated December 28, 2015, by and between MPLX LP and MW Logistics Services LLC	8-K	10.1	1/4/2016	001-35714		
10.44*	Executive Employment Agreement effective September 5, 2007 between MarkWest Hydrocarbon, Inc. and Frank Semple	8-K	10.1	9/11/2007	001-31239		
10.45	Voting Agreement, dated July 11, 2015, by and among MPLX LP, MPLX GP LLC, Sapphire Holdco LLC and M&R MWE Liberty, LLC	10-Q	10.1	8/3/2015	001-35714		
10.46	Voting Agreement, dated as of November 16, 2015, by and among MPLX LP, MPLX GP LLC, Sapphire Holdco LLC, Kayne Anderson Capital Advisors, L.P. and KA Fund Advisors, LLC	8-K	10.1	11/17/2015	001-35714		
10.47	Voting Agreement, dated as of November 16, 2015, by and among MPLX LP, MPLX GP LLC, Sapphire Holdco LLC, and Tortoise Capital Advisors, L.L.C.	8-K	10.2	11/17/2015	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
10.48+	Second Amended and Restated Limited Liability Company Agreement of MarkWest Utica EMG, L.L.C. dated December 4, 2015, between MarkWest Utica Operating Company, L.L.C. and EMG Utica, LLC	10-K	10.48	2/26/2016	001-35714		
10.49	Amended and Restated Transportation Services Agreement, dated January 1, 2015, between Hardin Street Marine LLC and Marathon Petroleum Company LP	8-K	10.1	4/6/2016	001-35714		
10.50	First Amendment to the Amended and Restated Transportation Services Agreement, dated March 31, 2016, between Hardin Street Marine LLC and Marathon Petroleum Company LP	8-K	10.2	4/6/2016	001-35714		
10.51	Amended and Restated Management Services Agreement, dated January 1, 2015, between Hardin Street Marine LLC and Marathon Petroleum Company LP	8-K	10.3	4/6/2016	001-35714		
10.52	Second Amended and Restated Employee Services Agreement, dated January 1, 2015, between Hardin Street Marine LLC and Marathon Petroleum Logistics Services LLC	8-K	10.4	4/6/2016	001-35714		
10.53*	Form of MPLX LP Performance Unit Award Agreement—Marathon Petroleum Corporation Officer	10-Q	10.6	5/2/2016	001-35714		
10.54*	Form of MPLX LP Phantom Unit Award Agreement—Marathon Petroleum Corporation Officer	10-Q	10.7	5/2/2016	001-35714		
10.55*	Form of MPLX LP Performance Unit Award Agreement	10-Q	10.8	5/2/2016	001-35714		
10.56*	Form of MPLX LP Phantom Unit Award Agreement—Officer	10-Q	10.9	5/2/2016	001-35714		
10.57	Series A Preferred Unit Purchase Agreement, dated as of April 27, 2016, by and among MPLX LP and the Purchasers party thereto	8-K	10.1	4/29/2016	001-35714		
10.58	Master Reorganization Agreement, dated September 1, 2016, by and among MPLX Holdings Inc., MarkWest Energy Partners, L.P., MWE GP LLC, MPLX LP, MPLX GP LLC, MPC Investment LLC, MPLX Logistics Holdings LLC and MarkWest Hydrocarbon, L.L.C.	8-K	10.1	9/6/2016	001-35714		
10.59	Second Amendment to Amended and Restated Operating Agreement, dated August 1, 2016, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	10-Q	10.2	10/31/2016	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
10.60	First Amendment to Employee Services Agreement, dated May 10, 2016, by and between Marathon Petroleum Logistics Services LLC, MPLX GP LLC and Marathon Pipe Line LLC	10-Q	10.1	8/3/2016	001-35714		
10.61	First Amendment to Amended and Restated Transportation Services Agreement, effective as of April 1, 2016, by and between Marathon Petroleum Company LP and Hardin Street Marine LLC	10-Q	10.2	8/3/2016	001-35714		
10.62	First Amendment to Amended and Restated Management Services Agreement, effective as of November 1, 2016, between Marathon Petroleum Company LP and Hardin Street Marine LLC					X	
10.63	First Amendment to Transportation Services Agreement, dated November 1, 2016, between Marathon Pipeline LLC and Marathon Petroleum Company LP (Texas City Products System)					X	
12.1	Computation of Ratio of Earnings to Fixed Charges					X	
14.1	Code of Ethics for Senior Financial Officers					X	
21.1	List of Subsidiaries					X	
23.1	Consent of Independent Registered Public Accounting Firm					X	
24.1	Power of Attorney of Directors and Officers of MPLX GP LLC					X	
31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934					X	
31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934					X	
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350						X
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350						X
101.INS	XBRL Instance Document					X	
101.SCH	XBRL Taxonomy Extension Schema					X	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase					X	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase					X	
101.DEF	XBRL Taxonomy Extension Definition Linkbase					X	
101.LAB	XBRL Taxonomy Extension Label Linkbase					X	

† The exhibits and schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K and will be provided to the Securities and Exchange Commission upon request.

* Indicates management contract or compensatory plan, contract or arrangement in which one or more directors or executive officers of the Registrant may be participants.

+ Application has been made to the Securities and Exchange Commission for confidential treatment of certain provisions of these exhibits. Omitted material for which confidential treatment has been requested and has been filed separately with the Securities and Exchange Commission.

Pursuant to Item 601(b)(4) of Regulation S-K, certain instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10% of the total consolidated assets of the Registrant. The Registrant hereby agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon its request.

Item 16. Form 10-K Summary

Not applicable.

SIGNATURES

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

February 24, 2017

MPLX LP

By: MPLX GP LLC
Its general partner

By: /s/ Paula L. Rosson
Paula L. Rosson
Senior Vice President and Chief Accounting Officer of MPLX GP LLC
(the general partner of MPLX LP)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on February 24, 2017 on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ Gary R. Heminger Gary R. Heminger	Chairman of the Board of Directors and Chief Executive Officer of MPLX GP LLC (the general partner of MPLX LP) (principal executive officer)
/s/ Pamela K.M. Beall Pamela K.M. Beall	Director, Executive Vice President and Chief Financial Officer of MPLX GP LLC (the general partner of MPLX LP) (principal financial officer)
/s/ Paula L. Rosson Paula L. Rosson	Senior Vice President and Chief Accounting Officer of MPLX GP LLC (the general partner of MPLX LP) (principal accounting officer)
* Donald C. Templin	Director and President of MPLX GP LLC (the general partner of MPLX LP)
* Michael L. Beatty	Director of MPLX GP LLC (the general partner of MPLX LP)
* David A. Daberko	Director of MPLX GP LLC (the general partner of MPLX LP)
* Timothy T. Griffith	Director of MPLX GP LLC (the general partner of MPLX LP)
* Christopher A. Helms	Director of MPLX GP LLC (the general partner of MPLX LP)
* Garry L. Peiffer	Director of MPLX GP LLC (the general partner of MPLX LP)
* Dan D. Sandman	Director of MPLX GP LLC (the general partner of MPLX LP)
* Frank M. Semple	Director of MPLX GP LLC (the general partner of MPLX LP)
* John P. Surma	Director of MPLX GP LLC (the general partner of MPLX LP)
* C. Richard Wilson	Director of MPLX GP LLC (the general partner of MPLX LP)

* The undersigned, by signing his name hereto, does sign and execute this report pursuant to the Power of Attorney executed by the above-named directors and officers of the general partner of the registrant, which is being filed herewith on behalf of such directors and officers.

By: /s/ Gary R. Heminger
Gary R. Heminger
Attorney-in-Fact

February 24, 2017

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COMPANY INFORMATION

Headquarters
200 East Hardin St.
Findlay, OH 45840
(419) 421-2414

MPLX LP Website
www.MPLX.com

Investor Relations Office
539 South Main St.
Findlay, OH 45840
MPLXInvestorRelations@marathonpetroleum.com

Lisa Wilson, Director Investor Relations
(419) 421-2071

Doug Wendt, Manager Investor Relations
(419) 421-2423

Denice Myers, Manager Investor Relations
(419) 421-2965

Independent Accountants
PricewaterhouseCoopers LLP
406 Washington St., Suite 200
Toledo, OH 43604

Stock Exchange Listing
New York Stock Exchange

Common Unit Symbol
MPLX

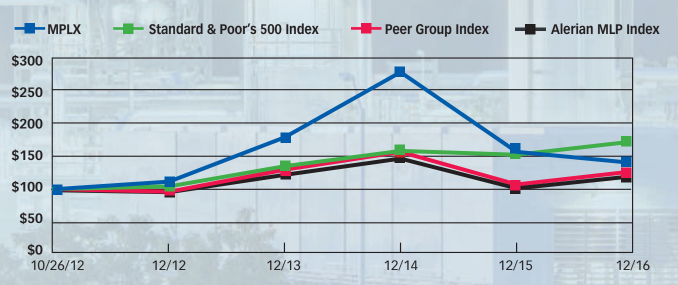
Principal Unit Transfer Agent
Computershare
250 Royall St.
Canton, MA 02021
(877) 373-6374 (toll free – U.S., Canada, Puerto Rico)
(781) 575-2879 (other non-U.S. jurisdictions)
web.queries@computershare.com

Annual Report on Form 10-K
Additional copies of the MPLX LP 2016 Annual Report may be obtained by contacting:
Public Affairs
539 South Main St.
Findlay, OH 45840
(419) 421-3577

Distributions
Distributions on units, as may be declared by the board of directors, are typically paid mid-month in February, May, August and November.

Tax Reporting
MPLX unitholders can access Schedule K-1 tax information by contacting:
Tax Package Support
PO Box 799060
Dallas, TX 75379
(800) 232-0011

COMPARISON OF CUMULATIVE TOTAL RETURN
Among MPLX LP, the S&P 500 Index, the Alerian MLP Index and Peer Group Index



The above graph compares the cumulative total return, assuming the reinvestment of distributions, of a $100 investment in our common units from Oct. 26, 2012 (the effective date of our IPO), to Dec. 31, 2016, compared to the cumulative total return of an investment in the S&P 500 Index, the Alerian MLP Index and an index of peer companies (selected by us) for the same period. Our peer group consists of the following companies: Buckeye Partners LP; Enbridge Energy Partners LP; Energy Transfer Partners LP; Enterprise Products Partners LP; Magellan Midstream Partners LP; ONEOK Partners LP; Phillips 66 Partners LP; Plains All American Pipeline LP; Sunoco Logistics Partners LP; Tesoro Logistics LP; Valero Energy Partners LP; Western Gas Partners LP; and Williams Partners LP.

The above performance graph is not "soliciting material" and will not be deemed to be filed with the Securities and Exchange Commission (SEC) or incorporated by reference into any of MPLX's filings with the SEC, except to the extent that we specifically incorporate it by reference into any such filings.

Non-GAAP Financial Measures

Adjusted earnings before interest, taxes, depreciation and amortization (EBITDA), distributable cash flow (DCF) and distribution coverage ratio are non-GAAP financial measures provided in this annual report. Adjusted EBITDA and DCF reconciliations to the nearest GAAP financial measure are included on Page 13 and in the MPLX Annual Report on Form 10-K for the year ended Dec. 31, 2016, filed with the SEC. Distribution coverage ratio is the ratio of DCF attributable to GP and LP unitholders to total GP and LP distributions declared. Adjusted EBITDA, DCF and distribution coverage ratio are not defined by GAAP and should not be considered in isolation of or as an alternative to net income attributable to MPLX, net cash provided by (used in) operating activities or other financial measures prepared in accordance with GAAP. Certain EBITDA forecasts were determined on an EBITDA-only basis. Accordingly, information related to the elements of net income, including tax and interest, are not available and, therefore, reconciliations of these non-GAAP financial measures to the nearest GAAP financial measures have not been provided.

Disclosures Regarding Forward-Looking Statements

This summary annual report wrap includes forward-looking statements. You can identify our forward-looking statements by words such as “anticipate,” “believe,” “design,” “estimate,” “expect,” “forecast,” “goal,” “guidance,” “imply,” “intend,” “objective,” “opportunity,” “outlook,” “plan,” “position,” “pursue,” “prospective,” “predict,” “project,” “potential,” “seek,” “strategy,” “target,” “could,” “may,” “should,” “would,” “will” or other similar expressions that convey the uncertainty of future events or outcomes. We have based our forward-looking statements on our current expectations, estimates and projections about our industry and our company. We caution that these statements are not guarantees of future performance and you should not rely unduly on them, as they involve risks, uncertainties and assumptions that we cannot predict. In addition, we have based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. While our management considers these assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, our actual results may differ materially from the future performance that we have expressed or forecast in our forward-looking statements. In accordance with “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995, we have included in our attached Form 10-K for the year ended Dec. 31, 2016, cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

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