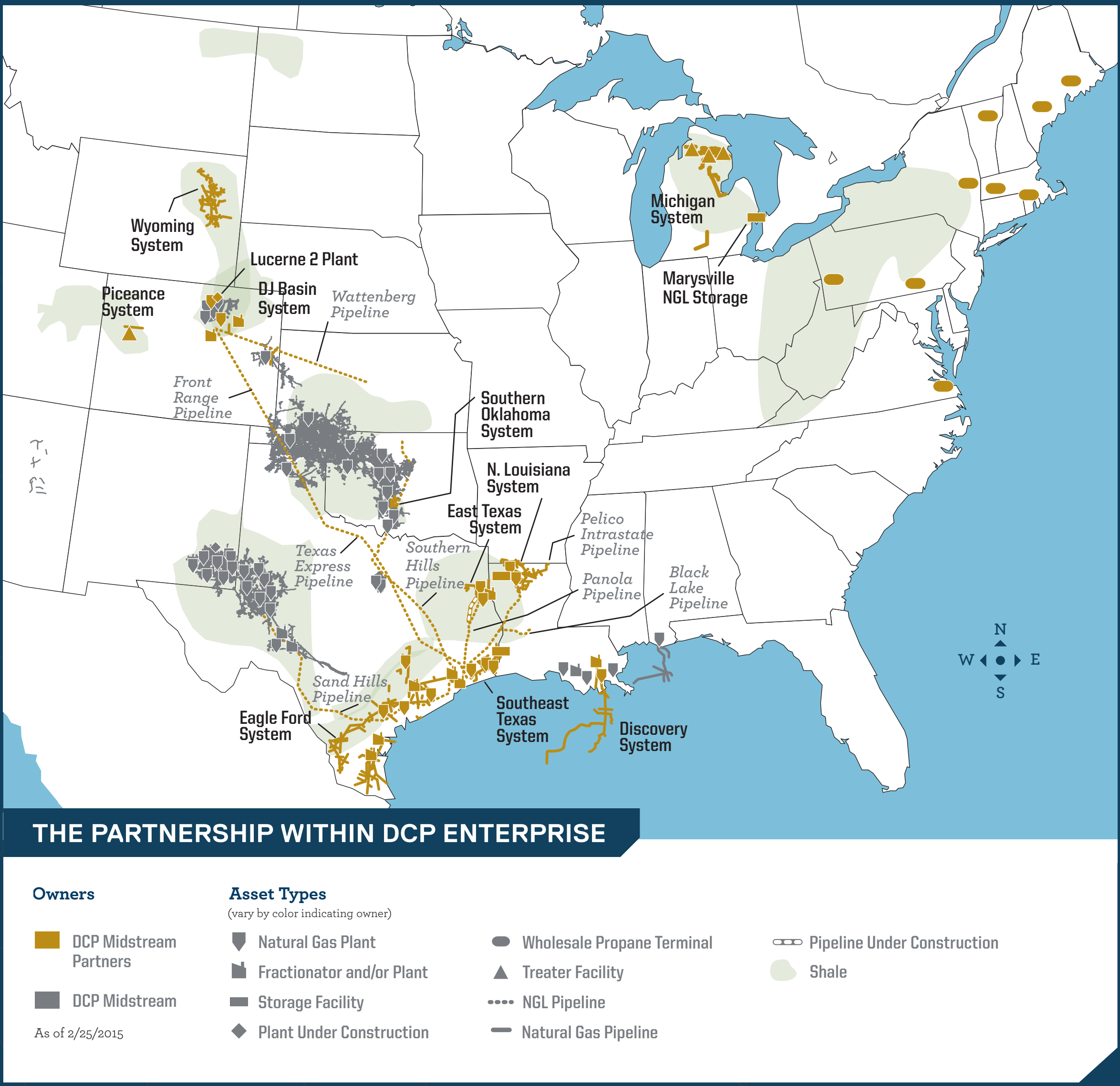
ANNUAL REPORT 2014

PROVEN TRACK RECORD

Positioned for the future

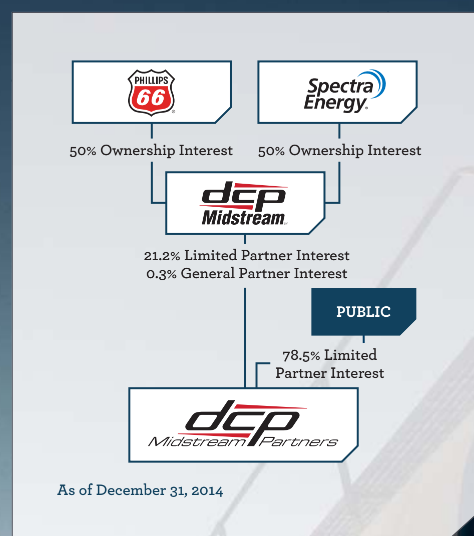
dcp Midstream Partners

DCP Midstream Partners, LP (NYSE: DPM), or the Partnership, is a midstream master limited partnership that gathers, compresses, treats, processes, transports, stores and sells natural gas; produces, fractionates, transports, stores and sells NGLs and recovers and sells condensate; and transports, stores and sells propane in wholesale markets.



COMPANY OVERVIEW

DCP Midstream Partners, LP (NYSE: DPM), or the Partnership, is managed by its general partner, which is 100 percent owned by DCP Midstream, LLC (DCP Midstream), a joint venture between its owners Phillips 66 and Spectra Energy Corp. DCP Midstream and the Partnership are collectively referred to as the “DCP enterprise.” The DCP enterprise is the nation’s largest natural gas gatherer and processor, and the largest producer of natural gas liquids in the U.S. Phillips 66 (NYSE: PSX) is one of the largest independent downstream energy companies with refining, marketing, midstream and chemicals businesses operating across the globe. Spectra Energy Corp (NYSE: SE) is one of North America’s premier natural gas infrastructure companies connecting natural gas supply sources to premium markets in the U.S. and Canada. Collectively, we call these entities our “sponsors” and our affiliation with them provides us with significant business opportunities. Through the ownership of our general partner and 21.2 percent of our outstanding limited partner units, our sponsors are invested in, and committed to, the success of the Partnership.



TO OUR UNITHOLDERS

Wouter T. van Kempen
Chairman and CEO
DCP Midstream Partners

William S. Waldheim
President and Director
DCP Midstream Partners

BY PACING INVESTMENT AND PREPARING FOR FUTURE GROWTH, DCP MIDSTREAM PARTNERS IS POSITIONED FOR AN INDUSTRY RECOVERY.

It was a year of record achievement for the Partnership—one that saw our 17th consecutive quarterly distribution increase, in keeping with our commitment to deliver sustainable growth for our unitholders. We are proud to have checked the box on all the promises we made for 2014, including the most important one, operating safely. Once again, the DCP enterprise held the number one safety ranking among the 10 largest midstream companies by the Gas Processors Association, and we experienced the best safety record in our history.

Our proven track record executing on our strategy saw us strengthen our position in key basins through dropdowns and organic projects, with an increase in total assets of 26 percent. Our increased size and scale delivers a growing revenue stream founded upon a diversified portfolio of assets and margins, and that translates to sustainable returns.

In 2014, we were fast out of the gate completing a record $1.15 billion dropdown to the Partnership which significantly boosted our Natural Gas Liquids (NGL) Logistics segment, took our Eagle Ford system ownership to 100 percent, gave way to entry into the Permian basin and expanded our footprint in the prolific DJ basin. In total, since our IPO, we have dropped almost $4 billion of assets to the Partnership.

We also successfully executed on our organic growth program, investing approximately $500 million in new projects during 2014. These included putting the Front Range Pipeline into service, expanding our O'Connor gas processing plant in the DJ basin and bringing our Goliad plant in the Eagle Ford into service. We also began construction on a new plant in the DJ, our Lucerne 2 plant, which will increase the Partnership's capacity to about half of the DCP enterprise's total DJ capacity when the plant goes into service in the second quarter of 2015. Our new NGL pipelines, Southern Hills and Sand Hills, ramped up quickly, exceeding expectations and leading to additional expansion of laterals and pumping stations.

As we grow the Partnership, we have been mindful to pace our investments with producer needs. We are not a "build it and they will come" company and being prudent and disciplined has resulted in strong capital efficiency with our systems filling up quickly. As we look ahead into the challenging environment of 2015, we will prudently manage our growth during this industry downturn, while maintaining optionality for the future. We'll do this by permitting plants in the DJ and Eagle Ford and ordering long lead equipment to prepare for future opportunities around our footprint so we can quickly ramp up when needed.

Quarterly Distributions Since IPO

Even in this challenging environment we continue to see great growth projects we can execute on. We have already announced two new projects for 2015 including the Grand Parkway gathering project in the DJ basin, which will lower field pressures for our customers and increase volumes to improve overall reliability of the system.

Early in 2015, we also announced our 15 percent interest in the formation of the Panola NGL pipeline joint venture to finance expansions on the Panola Pipeline, which transports NGLs approximately 180 miles from the Carthage hub in East Texas to Mont Belvieu. The joint venture will install 60 miles of new NGL pipeline to increase capacity by 50,000 barrels per day to 100,000 barrels per day, which will benefit the Partnership's extensive gathering and processing infrastructure in East Texas.

Through our successful strategy, we have added fee-based assets and contracts to our portfolio, further demonstrating our commitment to delivering sustainable cash flow for our unitholders. With these growing fee-based assets, and together with our hedging program, the Partnership was 95 percent fee-based or hedged in 2014 and is approximately 90 percent fee-based or hedged in 2015.

We believe in the long-term fundamentals for the industry, and we are confident in the integral role the midstream sector contributes to the country's energy needs. Our experienced management team has seen numerous commodity and business cycles. As we navigate the uncertainty of the current commodity environment, we will remain keenly focused on operational excellence, which is founded on our principles of risk management, reliability, capital efficiency, contract reformation and expense management.

As a "must-run" business, the majority of the gas produced in the country requires some level of treatment or conditioning, and the DCP enterprise is the largest processor in the U.S. In its own right, the Partnership has grown tremendously in its size and scale to rank in the top 10 natural gas processors and NGL producers on a standalone basis. All of this contributes to our readiness to be well positioned for an industry recovery.

We have not wavered from our commitment to grow a sustainable business, manage risk, and create and preserve value for our unitholders. We would like to thank our employees for their dedication to this effort and for their uncompromising ethic to work safely and with the highest standards of customer service. Our management team is confident our plans are achievable and reasonable, and we will manage through short-term challenges while maintaining our long-term strategy.

We remain committed to delivering on our promises to our unitholders, proven by our strong track record. Thank you for your support of the Partnership.

Wouter T. van Kempen
Chairman and Chief Executive Officer

William S. Waldheim
President

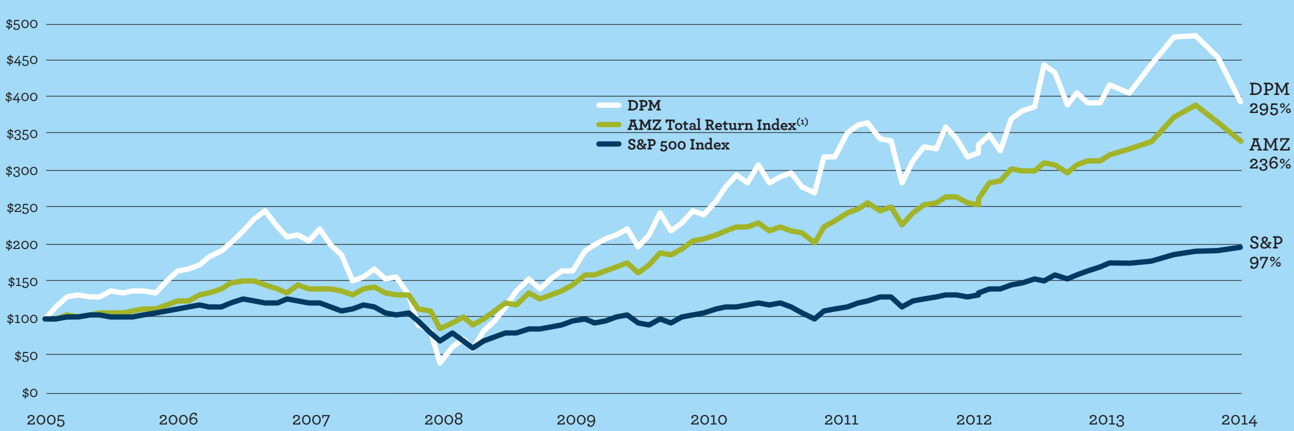
For the years ended (amounts in millions, except per unit amounts)	(2) 12/31/14	(2) 12/31/13	(2) 12/31/12
Statements of Operations Data			
Adjusted EBITDA(1)	$ 536	$ 386	$ 322
Adjusted net income attributable to partners(1)	$ 337	$ 236	$ 195
Adjusted net income per limited partner unit – basic and diluted(1)	$ 2.04	$ 1.80	$ 1.89
Wtd avg limited partners units outstanding – basic and diluted	106.6	78.4	54.5
As of (amounts in millions)			
Balance Sheet Data			
Total assets	$ 5,739	$ 4,567	$ 3,645
Long-term debt	$ 2,061	$ 1,590	$ 1,620
Partners' equity	$ 2,993	$ 1,985	$ 1,447
Noncontrolling interests	$ 33	$ 228	$ 189
Other Financial Data			
Cash distributions declared per unit (3)	$3.0525	$2.8630	$2.7000
For the years ended			
Operating Statistics			
Natural gas throughput (MMcf/d)	2,604	2,307	2,359
NGL gross production (Bbls/d)	157,722	121,970	115,945
NGL pipelines throughput (Bbls/d)	184,706	89,361	78,508
Propane sales volume (Bbls/d)	18,335	19,553	19,111

(1) Denotes a financial measure not presented in accordance with U.S. generally accepted accounting principles, or GAAP. Each such non-GAAP financial measure is reconciled to its most directly comparable GAAP financial measure on the inside back cover of this document.

(2) On March 30, 2012, we acquired a 66.67% interest in DCP Southeast Texas Holdings, GP (Southeast Texas system) from DCP Midstream, LLC. On November 2, 2012 and March 28, 2013, we acquired a 33.33% interest and 46.67% interest, respectively, in DCP SC Texas GP (Eagle Ford system) from DCP Midstream, LLC. On March 28, 2014, we acquired the Lucerne 1 plant from DCP Midstream, LLC. Our financial information gives retroactive effect to each of these acquisitions as a combination of entities under common control and has been accounted for similar to a pooling of interests. Earnings for periods prior to these acquisitions are allocated to predecessor operations to derive adjusted net income per limited part unit – basic and diluted.

(3) Cash distributions declared per limited partner unit represent cash distributions declared with respect to the four fiscal quarters of each year presented.

COMPARATIVE TOTAL RETURNS 12/01/05 - 12/31/14



The Partnership has outperformed the MLP sector and S&P 500 indexes on a total return basis since our initial public offering in December 2005.

(1) The Alerian MLP Total Return Index (NYSE: AMZX) is a composite of the 50 most prominent energy master limited partnerships that provides a comprehensive benchmark for this asset class. The index, which is calculated using a float-adjusted, capitalization-weighted methodology, is disseminated real-time on a total-return basis.

OUR BUSINESS

The midstream natural gas industry is the link between the exploration and production of natural gas, and the delivery of its components to end-use markets. Approximately 75 percent of the country's natural gas must be processed after it is produced and before it can enter the marketplace and serve end-users.

We are a must-run sector that gathers, compresses, treats, processes, transports, stores, and sells natural gas, as well as produces, fractionates, transports, stores and sells natural gas liquids, recovers and sells condensate, and transports, stores and sells propane in wholesale markets.

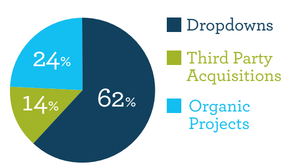
Our three business segments are Natural Gas Services, NGL Logistics and Wholesale Propane Logistics.

OUR STRATEGY

Size and Scale to Deliver Sustainable Distributions

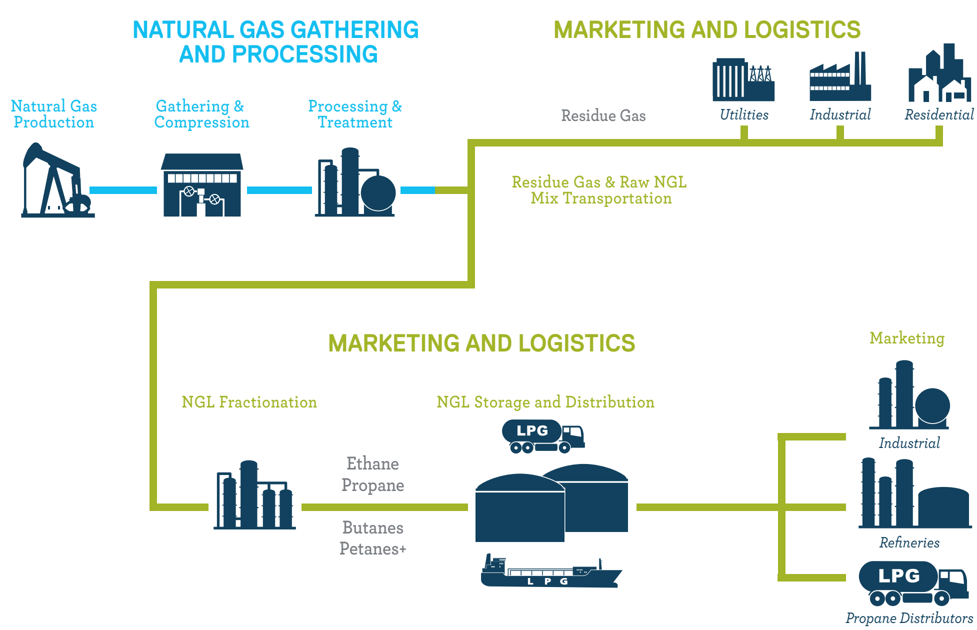
Our primary business objectives are to have sustained company profitability, a strong balance sheet and profitable growth that results in increasing our cash distribution per unit over time. We employ a multifaceted strategy of building on organic expansion opportunities around our established footprint, executing on dropdowns with our general partner, DCP Midstream, and pursuing strategic third party acquisitions.

Growth Since IPO



Through this successful strategy, the Partnership has grown to become one of the top 10 natural gas processors and natural gas producers in the U.S.

As gas is produced at the wellhead, it is first gathered and delivered to a centralized point for processing. The gas processing plant collectively separates the natural gas liquids (NGLs)—ethane, propane, butane, and other NGLs—from the gas stream. The processed gas now meets long-haul gas pipeline specifications and is transported to end-users. The separated NGLs are transported by NGL pipelines or trucks to a fractionation facility where the NGLs are further separated into their constituent parts before transport to end-use markets.



NATURAL GAS SERVICES

Our assets in this segment claim an attractive market position, with an aggregate of over 3.5 billion cubic feet per day of processing capacity and approximately 11,750 miles of pipeline. In total, the Natural Gas Services segment consists of 22 plants and five fractionators.

This segment boasts a significant presence in key basins, with our assets spanning from our offshore Gulf Coast Discovery system through the Eagle Ford, East Texas, Northern Louisiana, to our Oklahoma system in the Midcontinent, our DJ Basin and Wyoming systems in the Rockies, and the Antrim Shale in Michigan. Our diverse geographic footprint is a strong attribute as it provides us with access to multiple resource plays.

Our largest business segment saw natural gas throughput volumes and NGL production increase year over year primarily due to growth in our Eagle Ford and DJ Basin systems. In 2014, we put the Goliad plant in service and expanded our O'Connor plant, with both filling up quickly. Our overall utilization for these new plants averaged 85 percent, highlighting strong capital efficiency, which is a key indicator of our ability to match pace with producer demand.

As part of the dropdowns in 2014, we received the Lucerne 1 plant in the DJ basin. Together with the new Lucerne 2 plant, scheduled to be in service in the second quarter of 2015, the Partnership will own half of the DCP enterprise's 800 million cubic feet per day of processing capacity in the DJ basin. Both the O'Connor and Lucerne 2 plants are supported by fee-based contracts with minimum throughput commitments.

We also dropped the remaining 20 percent of the Eagle Ford system into the Partnership, and

OUR LARGEST BUSINESS SEGMENT SAW NATURAL GAS THROUGHPUT VOLUMES AND NGL PRODUCTION INCREASE PRIMARILY DUE TO GROWTH IN OUR EAGLE FORD AND DJ BASIN SYSTEMS.

this area continues to see strong production due to its economic cost of drilling and proximity to the Mont Belvieu market. Location matters, and the Partnership is well situated in the core area of the basin. Altogether, the Eagle Ford system, through its integrated system of seven plants, has 1.2 Bcf/d of natural gas processing capacity and has 1.4 Bcf/d of natural gas gathering capacity. This excess gathering capacity provides the Partnership with the ability to offload excess gas production to third parties providing potential earnings growth. It also provides flexibility to the Partnership in determining when the next plant in the Eagle Ford may be needed which is dependent on producer drilling activity and capacity needs.

With our 40 percent interest in the Discovery System, the fee-based Keathley Canyon connector pipeline project was placed into service in early 2015. This is a predominantly fee-based project backed by minimum volume commitments.

In looking ahead, we approved the fee-based Grand Parkway gathering project in the DJ basin in the first quarter, which will lower pipeline pressures for producers providing greater reliability. This project will be in service by the end of 2015.

NGL
LOGISTICS

The NGL Logistics segment consists of our Marysville NGL storage facility, four fractionators and our NGL pipelines that are integrated with gas processing plants owned by the Partnership, DCP Midstream and third parties.

Since 2010, we have been growing our downstream capability across our footprint to deliver value to the DCP enterprise. In doing so, we've become a substantial entity, transformed into an integrated full service midstream provider.

This segment grew tremendously in 2014, becoming a significant contributor to the growth in the Partnership's fee-based earnings. We dropped the Sand Hills and Southern Hills NGL pipelines into the Partnership as part of the $1.15 billion dropdown in early 2014. With this dropdown and our interests in the Texas Express and Front Range pipelines, our NGL pipeline throughput increased 107 percent, making the Partnership the third largest NGL pipeline operator in the country.

Both Sand Hills and Southern Hills pipelines ramped up quickly ahead of schedule, and construction is already underway on two Sand Hills laterals, Red Bluff Lake and Lea County, which will open up much needed pipeline capacity in the Delaware basin and southeast New Mexico. It will also connect to DCP Midstream's Zia II plant which is expected to be in service in mid-2015. We are actively connecting third party facilities, extending our NGL footprint and adding value for the services we offer. We are also expanding Sand Hills capacity through new pump stations, the first of which will add 40,000 barrels per day of takeaway capacity from the Permian area.

Early in 2015, we announced our 15 percent interest in the formation of the Panola NGL pipeline joint venture, which extends approximately 180 miles from Carthage, Texas to Mont Belvieu, Texas. The joint venture plans to install approximately 60 miles of new NGL pipeline and increase capacity by 50,000 barrels per day, benefiting our extensive gathering and processing infrastructure presence in East Texas. This project is expected to be in service in the first quarter of 2016.

NGL PIPELINE throughput increased 107%

At our Marysville storage facility in Michigan, we expanded our ethane storage serving the Sarnia, Canada refining and chemical market. Our Marysville ethane and butane storage capabilities provide important reliability to surrounding basins. We have begun construction on a liquids handling project which will improve our ability to receive and deliver NGL products at Marysville by truck and rail. The facility also has potential to expand its current cavern capability to address robust demand.

WHOLESALE PROPANE LOGISTICS

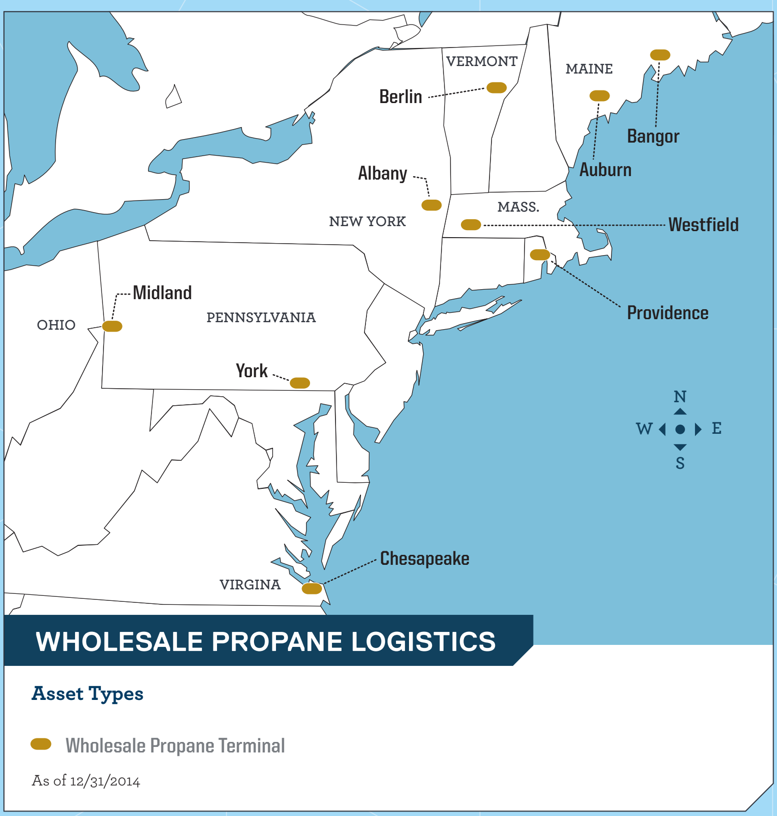
Our Wholesale Propane Logistics segment enjoys a very favorable market position as one of the largest wholesale propane suppliers in the Northeast and Mid-Atlantic.

This wholesale propane network of terminals provides important market access to Marcellus producers and is an integral part of this basin's development.

Our business model leverages the strong logistics capabilities of the DCP enterprise. The combination of these capabilities and our supply diversity provides us a competitive advantage, allowing us to not only supply our base business but also to capture upside opportunities during favorable marketing conditions.

While this is our smallest segment from a margin perspective, the Wholesale Propane Logistics segment continues to be a consistent earnings contributor to the Partnership, with the majority of our earnings from this segment generated during the winter heating season. Our contracts tie the sales and purchase prices to the same index, which essentially locks in a fixed margin.

In 2014, we converted our Chesapeake propane import terminal in Virginia to a butane export terminal, capable of handling 7,000 to 8,000 barrels a day of product. This project provides needed international market access to Marcellus butane production. The terminal became operational at the end of 2014, is backed by volume commitments and has potential to be expanded to meet increased Marcellus producer demand.



11% of operating revenues IN 2014.

CORPORATE OFFICERS

Wouter T. van Kempen
Chairman and CEO

William S. Waldheim
President and Director

Sean P. O'Brien
Group Vice President and CFO

Michael S. Richards
Vice President, General Counsel and Secretary

BOARD OF DIRECTORS

Wouter T. van Kempen
Chairman and CEO

Fred J. Fowler
Director

Frank A. McPherson
Director

Thomas C. Morris
Director

William S. Waldheim
President and Director

Guy G. Buckley
Director

R. Mark Fiedorek
Director

Andy Viens
Director

Brian R. Wenzel
Director

RECONCILIATION OF NON-GAAP MEASURES

(amounts in millions, except per unit amounts)

	(1) 12/31/14	(1) 12/31/13	(1) 12/31/12
Net income attributable to partners	$ 423	$ 200	$ 216
Interest expense	86	52	42
Depreciation, amortization and income tax expense, net of noncontrolling interests	113	97	85
Non-cash commodity derivative mark-to-market	(86)	37	(21)
Adjusted EBITDA	$ 536	$ 386	$ 322
Net cash provided by operating activities	$ 524	$ 345	$ 102
Interest expense	86	52	42
Distributions from unconsolidated affiliates, net of earnings	(45)	(6)	–
Net changes in operating assets and liabilities	82	(8)	219
Net income attributable to noncontrolling interests, net of depreciation and income tax	(17)	(23)	(20)
Discontinued construction projects	(3)	(8)	–
Non-cash commodity derivative mark-to-market	(86)	37	(21)
Other, net	(5)	(3)	–
Adjusted EBITDA	$ 536	$ 386	$ 322
Net income attributable to partners	$ 423	$ 200	$ 216
Non-cash derivative mark-to-market	(86)	36	(21)
Adjusted net income attributable to partners	$ 337	$ 236	$ 195
Less: Adjusted net income attributable to predecessor operations	(6)	(25)	(51)
Adjusted general partner's interest in net income	(114)	(70)	(41)
Adjusted net income allocable to limited partners	$ 217	$ 141	$ 103
Adjusted net income per limited partner unit – basic and diluted	$ 2.04	$ 1.80	$ 1.89

(1) On March 30, 2012, we acquired a 66.67% interest in DCP Southeast Texas Holdings, GP (Southeast Texas system) from DCP Midstream, LLC. On November 2, 2012 and March 28, 2013, we acquired a 33.33% interest and 46.67% interest, respectively, in DCP SC Texas GP (Eagle Ford system) from DCP Midstream, LLC. On March 28, 2014, we acquired the Lucerne 1 plant from DCP Midstream, LLC. Our financial information gives retroactive effect to each of these acquisitions as a combination of entities under common control and has been accounted for similar to a pooling of interests. Earnings for periods prior to these acquisitions are allocated to predecessor operations to derive adjusted net income per limited part unit – basic and diluted.

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

or

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

For the transition period from to

Commission File Number: 001-32678

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

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

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

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 Partner 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 Exchange Act of 1934, or the 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 Act 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 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. ☒

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 of the registrant on June 30, 2014, was approximately $4,878,338,000. The aggregate market value was computed by reference to the last sale price of the registrant's common units on the New York Stock Exchange on June 30, 2014.

As of February 19, 2015, there were outstanding 113,950,115 common units representing limited partner interests.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

DCP MIDSTREAM PARTNERS, LP
FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2014

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

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

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

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

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

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

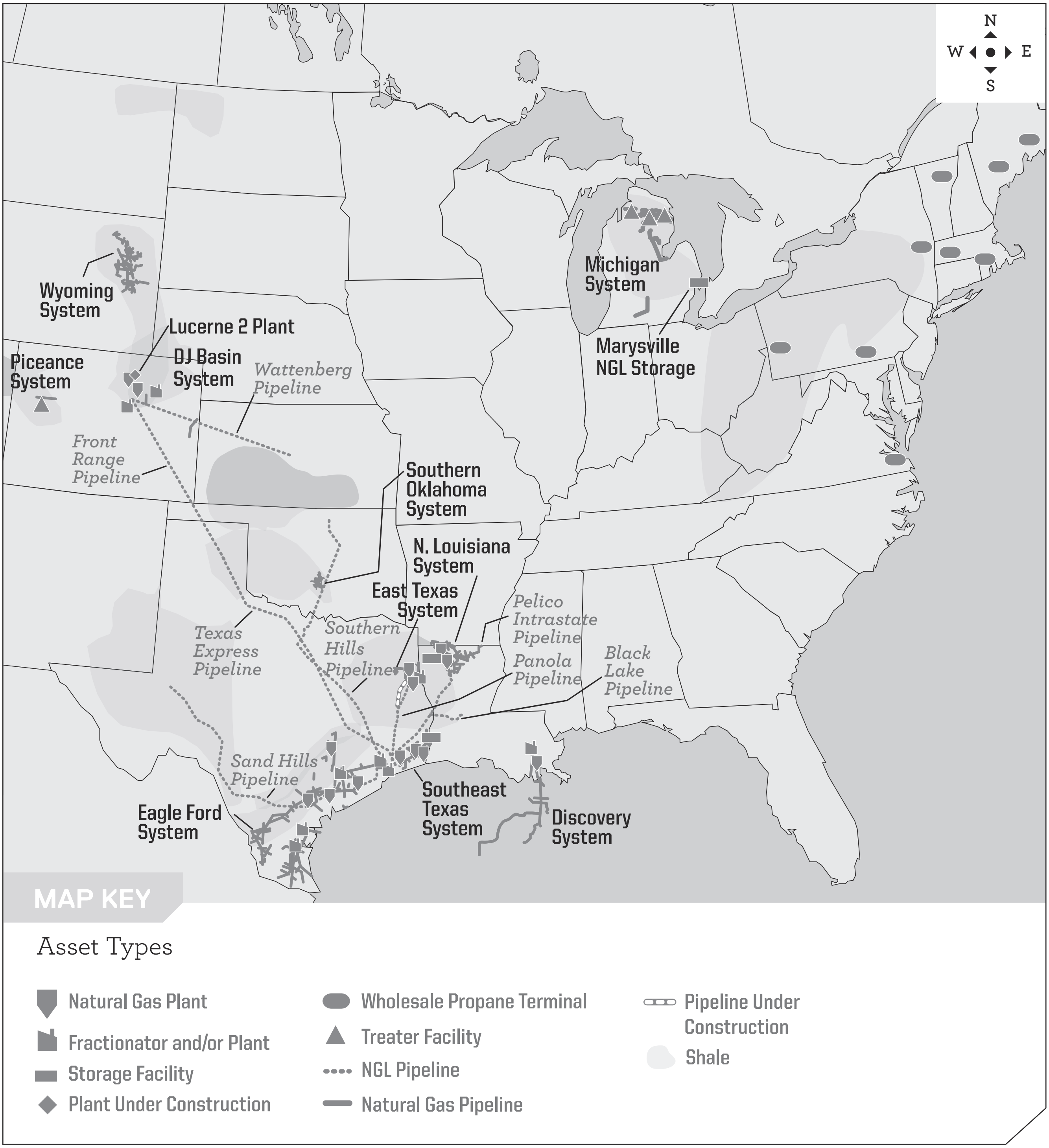
PART I

Item 1. ***Business***

OUR PARTNERSHIP

DCP Midstream Partners, LP (along with its consolidated subsidiaries, “we,” “us,” “our,” or the “partnership”) is a Delaware limited partnership formed in 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are currently engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGLs and recovering and selling condensate; and transporting, storing and selling propane in wholesale markets. Supported by our relationship with DCP Midstream, LLC and its owners, Phillips 66 and Spectra Energy Corp and its affiliates, or Spectra Energy, we are dedicated to executing our growth strategy by constructing and acquiring additional assets.

Our operations are organized into three business segments: Natural Gas Services, NGL Logistics and Wholesale Propane Logistics. A map representing the geographic location and type of our assets for all segments is set forth below. Additional maps detailing the individual assets can be found on our website at *www.dcppartners.com*. Our website and the information contained on that site, or connected to that site, are not incorporated by reference into this report. For more information on our segments, see the *“Our Operating Segments*” discussion below.



OVERVIEW AND STRATEGIES

Our Business Strategies

Our primary business objectives are to have sustained company profitability, a strong balance sheet and profitable growth thereby increasing our cash distribution per unit over time. We intend to accomplish these objectives by prudently executing the following business strategies:

Build: capitalize on organic expansion opportunities. We continually evaluate economically attractive organic expansion opportunities to construct midstream systems in new or existing operating areas. For example, we believe there are opportunities to expand several of our gas gathering systems to attach increased volumes of natural gas produced in the areas of our operations or to build new processing capacity. We also believe there are opportunities to continue to expand our NGL Logistics and Wholesale Propane Logistics businesses.

Dropdown: maximize opportunities provided by our partnership with DCP Midstream, LLC. We plan to execute our growth in part through pursuing economically attractive dropdown opportunities from DCP Midstream, LLC. We believe there will continue to be opportunities as DCP Midstream, LLC continues to build its infrastructure. However, we cannot say with any certainty that these opportunities will be made available to us, or that we will choose to pursue any such opportunity.

Acquire: pursue strategic third party acquisitions. We pursue economically attractive and strategic third party acquisition opportunities within the midstream energy industry, both in new and existing lines of business, and geographic areas of operation.

Our Competitive Strengths

We believe that we are well positioned to execute our business strategies and achieve one of our primary business objectives of increasing our cash distribution per unit because of the following competitive strengths:

Strategically located assets. Each of our business segments has assets that are strategically located in areas with the potential for increasing each of our business segments' volume throughput and cash flow generation. Our Natural Gas Services segment has a strategic presence in several active producing areas including Colorado, the Gulf of Mexico, Louisiana, Michigan, Oklahoma, Texas, and Wyoming. These systems provide a variety of services to our customers including gathering, compressing, treating, processing, transporting and storing natural gas, and fractionating NGLs. Our NGL Logistics segment has strategically located NGL transportation pipelines in Colorado, Kansas, Oklahoma, Louisiana, and Texas which are major NGL producing regions, NGL fractionation facilities in Colorado and the Gulf Coast and an NGL storage facility in Michigan. Our NGL pipelines connect to various natural gas processing plants and transport the NGLs to large fractionation facilities, a petrochemical plant, a third party underground NGL storage facility and other markets along the Gulf Coast. Our NGL storage facility in Michigan is strategically adjacent to the Sarnia, Canada refinery and petrochemical corridor. Our Wholesale Propane Logistics Segment has terminals in the mid-Atlantic, northeastern and upper midwestern states that are strategically located to receive and deliver propane to some of the largest demand areas for propane in the United States. The strategic location of our assets, coupled with their geographic diversity and our reputation for running our business reliably and effectively, presents us with continuing opportunities to provide competitive services to our customers and attract new natural gas production.

Affiliation with DCP Midstream, LLC and its owners. Our relationship with DCP Midstream, LLC and its owners, Phillips 66 and Spectra Energy, should continue to provide us with significant business opportunities. DCP Midstream, LLC is the largest processor of natural gas, the largest producer of NGLs and the third-largest NGL pipeline operator in the United States. This relationship also provides us with access to a significant pool of management talent. We believe our strong relationships throughout the energy industry, including with major producers of natural gas and NGLs in the United States, will help facilitate the implementation of our strategies. Additionally, we believe DCP Midstream, LLC, which operates most of our assets on our behalf, has established a reputation in the midstream business as a reliable and cost-effective supplier of services to our customers, and has a track record of safe, efficient and environmentally responsible operation of our facilities.

We believe we are an important growth vehicle and a key source of funding for DCP Midstream, LLC to pursue the organic construction, expansion and acquisition of midstream natural gas, NGL, wholesale propane and other complementary midstream energy businesses and assets. DCP Midstream, LLC has also provided us with growth opportunities through acquisitions directly from it and joint ventures with it. We believe we will have future opportunities to make additional acquisitions with or directly from DCP Midstream, LLC as well as form joint ventures with it; however, we cannot say with any certainty which, if any, of these opportunities may be made available to us, or if we will choose to pursue any such opportunity. In addition, through our relationship with DCP Midstream, LLC and its owners, we believe we have strong commercial relationships throughout the energy industry and access to DCP Midstream, LLC's broad operational, commercial, technical, risk management and administrative infrastructure.

DCP Midstream, LLC has a significant interest in us through its approximately 0.3% general partner interest, 21.2% limited partner interest and its ownership of our incentive distribution rights.

Stable cash flows. Our operations consist of a favorable mix of fee-based and commodity-based services, which together with our commodity hedging program, generate relatively stable cash flows. While certain of our gathering and processing contracts subject us to commodity price risk, we have mitigated a portion of our currently anticipated commodity price risk associated with the equity volumes from our gathering and processing operations through 2015 with fixed price commodity swaps. Additionally, growth in our fee-based earnings will reduce the impact of unhedged margins and allow us to continue to generate relatively stable cash flows.

Integrated package of midstream services. We provide an integrated package of services to natural gas producers, including gathering, compressing, treating, processing, transporting, storing and selling natural gas, as well as producing, fractionating, transporting, storing and selling NGLs and recovering and selling condensate. We believe our ability to provide all of these services gives us an advantage in competing for new supplies of natural gas because we can provide substantially all services that producers, marketers and others require to move natural gas and NGLs from wellhead to market on a cost-effective basis.

Comprehensive propane logistics systems. We have multiple propane supply sources and terminal locations to transport, store and sell propane and other liquefied petroleum gases. We believe our diversity of supply sources and logistics capabilities along with our storage assets and services allow us to provide our customers with reliable supplies of propane and other liquefied petroleum gases during periods of tight supply. These capabilities also allow us to moderate the effects of commodity price volatility and reduce significant fluctuations in our sales volumes.

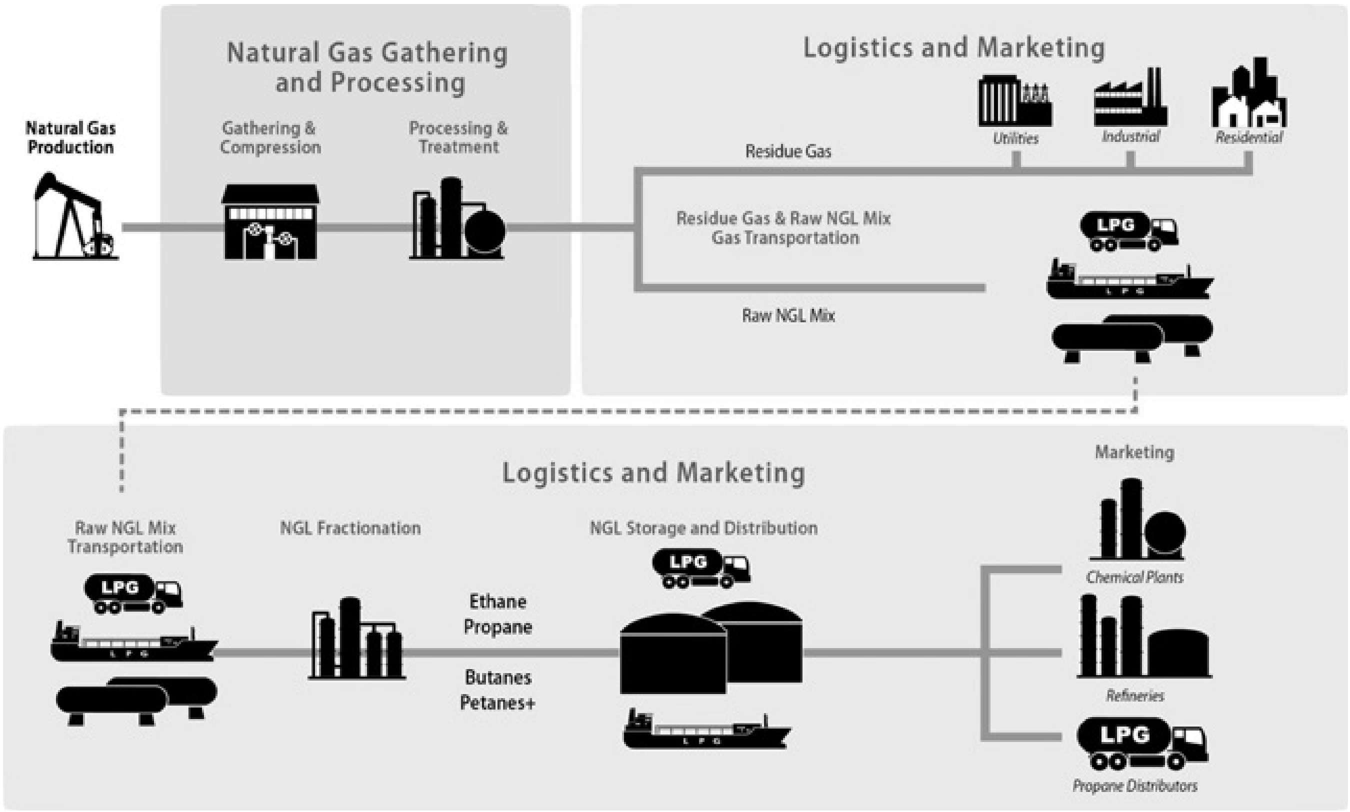
Experienced management team. Our senior management team and board of directors include some of the most senior officers of DCP Midstream, LLC and other energy companies who have extensive experience in the midstream industry. We believe our management team has a proven track record of enhancing value through organic growth, dropdowns and the acquisition, optimization and integration of midstream assets.

Midstream Natural Gas Industry Overview (Natural Gas Services and NGL Logistics)

General

The midstream natural gas industry is the link between exploration and production of natural gas and the delivery of its components to end-use markets, and consists of the gathering, compressing, treating, processing, transporting, storing and selling of natural gas, and producing, fractionating, transporting, storing and selling NGLs.

Once natural gas is produced from wells, producers then seek to deliver the natural gas and its components to end-use markets. The following diagram illustrates the natural gas gathering, processing, fractionation, storage and transportation process, which ultimately results in natural gas and its components being delivered to end-users.



Natural Gas Gathering

The natural gas gathering process begins with the drilling of wells into gas-bearing rock formations. Once the well is completed, the well is connected to a gathering system. Onshore gathering systems generally consist of a network of small diameter pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Natural Gas Compression

Gathering systems are generally operated at design pressures that will maximize the total throughput from all connected wells. Since wells produce at progressively lower field pressures as they deplete, it becomes increasingly difficult to deliver the remaining lower pressure production from the well against the prevailing gathering system pressures. Natural gas compression is a mechanical process in which a volume of wellhead gas is compressed to a desired higher pressure, allowing gas to flow into a higher pressure downstream pipeline to be brought to market. Field compression is typically used to lower the pressure of a gathering system or to provide sufficient pressure to deliver gas into a higher pressure downstream pipeline. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise would not be produced.

Natural Gas Processing

The principal component of natural gas is methane, but most natural gas produced at the wellhead also contains varying amounts of NGLs including ethane, propane, normal butane, isobutane and natural gasoline. NGLs have economic value and are utilized as a feedstock in the petrochemical and oil refining industries or directly as heating, engine or industrial fuels. Long-haul natural gas pipelines have residue natural gas specifications as to the maximum NGL content of the gas to be shipped. In order to meet quality standards for long-haul pipeline transportation, natural gas collected at the wellhead through a gathering system may need to be processed to separate hydrocarbon liquids from the natural gas that may have higher values as NGLs. NGLs are typically recovered by cooling the natural gas until the NGLs become separated through condensation. Cryogenic recovery methods are processes where this is accomplished at temperatures lower than negative 150°F. These methods provide higher NGL recovery yields.

In addition to NGLs, natural gas collected at the wellhead through a gathering system may also contain impurities, such as water, sulfur compounds, nitrogen or helium, which must also be removed to meet the quality standards for long-haul pipeline transportation. As a result, gathering systems and natural gas processing plants will typically provide ancillary services prior to processing such as dehydration, treating to remove impurities and condensate separation. Dehydration removes water from the natural gas stream, which can form ice when combined with natural gas and cause corrosion when combined with carbon dioxide or hydrogen sulfide. Natural gas with a carbon dioxide or hydrogen sulfide content higher than permitted by pipeline quality standards requires treatment with chemicals called amines at a separate treatment plant prior to processing. Condensate separation involves the removal of liquefied hydrocarbons from the natural gas stream. Once the condensate has been removed, it may be stabilized for transportation away from the processing plant via truck, rail, or pipeline.

Natural Gas and NGL Transportation and Storage

After gas collected through a gathering system is processed to meet quality standards required for transportation and NGLs have been extracted from natural gas, the residue natural gas is shipped on long-haul pipelines or injected into storage facilities. The NGLs are typically transported via NGL pipelines or trucks to a fractionator for separation of the NGLs into their individual components. Natural gas and NGLs may be held in storage facilities to meet future seasonal and customer demands. Storage facilities can include marine, pipeline and rail terminals, and underground facilities consisting of salt caverns and aquifers used for storage of natural gas and various liquefied petroleum gas products including propane, mixed butane, and normal butane. Rail, truck and pipeline connections provide varying ways of transporting natural gas and NGLs to and from storage facilities.

Wholesale Propane Logistics Overview

General

Wholesale propane logistics covers the receipt of propane from processing plants, fractionation facilities and crude oil refineries, the transportation of that propane by pipeline, rail or ship to terminals and storage facilities, the storage of propane and the delivery of propane to distributors.

Production of Propane

Propane is extracted from the natural gas stream at processing plants, separated from NGLs at fractionation facilities or separated from crude oil during the refining process. Most of the propane that is consumed in the United States is produced at processing plants, fractionation facilities and refineries located in the United States or in foreign locations, particularly Canada, the North Sea, East Africa and the Middle East. There are a number of processing plants, fractionation facilities and corresponding propane production in the northeastern United States.

Propane Demand

Propane demand is typically highest in suburban and rural areas where natural gas is not readily available, such as the northeastern United States. Propane is supplied by wholesalers to retailers to be sold to residential and commercial consumers primarily for heating and industrial applications. Propane demand is typically highest in the winter heating season months of October through April.

Transportation and Storage

Due to the nature of the regions' propane production and relatively high demand, the mid-Atlantic and northeastern United States are importers of propane. These areas rely on pipeline, marine and rail sources for incoming supplies from both domestic and foreign locations. Independent terminal operators and wholesale distributors, own, lease or have access to propane storage facilities that receive supplies via pipeline, rail or ship. Generally, inventories in the propane storage facilities increase during the spring and summer months for delivery to customers during the fall and winter heating season when demand is typically at its peak.

Delivery

Often, upon receipt of propane at pipeline, rail and marine terminals, product is delivered to customer trucks or is stored in tanks located at the terminals or in off-site bulk storage facilities for future delivery to customers. Most terminals and storage facilities have a tanker truck loading facility commonly referred to as a "rack." Typically independent retailers will rely on independent trucking companies to pick up propane at the propane wholesaler's rack and transport it to the retailer at its location.

OUR OPERATING SEGMENTS

Natural Gas Services Segment

General

Our Natural Gas Services segment consists of a geographically diverse complement of assets and ownership interests that provide a varied array of wellhead to market services for our producer customers. These services include gathering, compressing, treating, processing, transporting and storing natural gas, and fractionating NGLs. These assets are positioned in certain areas with active drilling programs and opportunities for organic growth. Our Natural Gas Services segment owns or operates assets in seven states in the continental United States: Arkansas, Colorado, Louisiana, Michigan, Oklahoma, Texas and Wyoming. The assets in these states include our Eagle Ford system (of which the remaining 20% interest was acquired in March 2014), our East Texas system, our Southeast Texas system, our Michigan system, our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our 75% operating interest in the Piceance system, our 40% limited liability company interest in the Discovery system located off and onshore in Southern Louisiana and our DJ Basin system, including the Lucerne 1 and Lucerne 2 plants acquired in March 2014. This geographic diversity helps to mitigate our natural gas supply risk in that we are not tied to one natural gas resource type or producing area. We believe our current geographic mix of assets will be an important factor for maintaining overall volumes and cash flow for this segment.

During 2014, the volume throughput on our assets was in excess of 2.5 Bcf/d, originating from a diversified mix of customers. Our systems each have significant customer acreage dedications that will continue to provide opportunities for growth as those customers execute their drilling plans over time. Our gathering systems also attract new natural gas volumes through numerous smaller acreage dedications and also by contracting with undedicated producers who are operating in or around our gathering footprint. During 2014, the combined NGL production from our processing facilities was in excess of 150,000 Bbls/d and was delivered and sold into various NGL takeaway pipelines or transported by truck.

Our natural gas systems have the ability to deliver gas into numerous downstream transportation pipelines and markets. Many of our outlets transport gas to premium markets in the eastern United States, further enhancing the competitiveness of our commercial efforts in and around our natural gas gathering systems.

Gathering and Transmission Systems, Plants, Fractionators and Storage Facilities

The following is operating data for our systems:

2014 Operating Data

System	Ownership Interest	Plants	Approximate Gas Gathering and Transmission Systems (Miles)	Fractionators	Approximate Net Nameplate Plant Capacity (MMcf/d) (a)	Approximate Natural Gas Storage Capacity (Bcf) (a)	Natural Gas Throughput (MMcf/d) (a)	NGL Production (Bbls/d) (a)
Eagle Ford	100%	7(d)	6,105	3	1,160(d)	—	960	79,855
Southeast Texas	100%	3(d)	675	—	400(d)	14	138	8,540
East Texas (b)	100%	3(d)	900	1	860(d)	—	666	33,811
Michigan	100%	3(e)	440	—	420(e)	—	283	—
DJ Basin	100%	2(d)	0	—	195(d)	—	174	20,747
N. Louisiana	100%	2(d)	1,455	—	160(d)	1(f)	163	3,873
Piceance	75%	1(e)	40	—	68(e)	—	54	1,321
Discovery (c)	40%	1(d)	510	1	240(d)	—	109	5,917
Southern Oklahoma	100%	—	225	—	—	—	17	—
Wyoming	100%	—	1,400	—	—	—	40	3,658
Total		22	11,750	5	3,503	15	2,604	157,722

(a) Represents total capacity or total volumes allocated to our proportionate ownership share for 2014 divided by 365 days.
(b) Our East Texas system is comprised of one gas processing complex containing four plants, as well as the Crossroads and George Gray processing plants.
(c) Represents an asset operated by a third party.
(d) Represents NGL extraction plants and the associated processing capacity.
(e) Represents treating plants and the associated treating capacity.
(f) Represents an asset owned and operated by a third party.

Our Eagle Ford system is a fully integrated midstream business in Fayette, Goliad, Jackson, Jim Wells, Lavaca, Live Oak and Nueces counties in Texas which includes gathering systems, production from 900,000 acres supported by acreage dedications or throughput commitments under long-term predominantly percent-of-proceeds agreements, cryogenic natural gas processing plants and fractionation facilities.

Our Southeast Texas system is a fully integrated midstream business which includes natural gas pipelines, three natural gas processing plants in Liberty and Jefferson Counties, of which two are temporarily idled, and natural gas storage assets in Beaumont. Our Southeast Texas gas storage facility is primarily managed by us for our own account.

Our East Texas system includes one gas processing complex containing four natural gas processing plants, as well as the George Gray and the Crossroads processing plants. Our East Texas system gathers, transports, compresses, treats and processes natural gas and NGLs. Our East Texas facility may also fractionate NGLs, which can be marketed at nearby petrochemical facilities. Our East Texas system, located near Carthage, Texas, includes a natural gas processing complex that is connected to its gathering system, as well as third party gathering systems.

Our Michigan system consists of three natural gas treating plants, a gas gathering system and various residue pipeline interests primarily located in northern Michigan.

Our DJ Basin system consists of three gas processing plants in the Denver-Julesburg Basin, or DJ Basin, in Weld County, Colorado. The O'Connor plant commenced operations in the fourth quarter of 2013 and its expansion to 160 MMcf/d was placed into service in March 2014. The 35 MMcf/d Lucerne 1 plant, as well as construction for the 200 MMcf/d Lucerne 2 plant were acquired in March 2014. The Lucerne 2 plant is expected to be complete in the second quarter of 2015. Our DJ Basin system delivers NGLs to the Wattenberg, Front Range and Texas Express pipelines in our NGL Logistics segment.

Our Northern Louisiana system includes our Minden and Ada systems, which gather natural gas from producers and deliver it for processing to the processing plants. It also includes our Pelico system, which stores natural gas and transports it to markets. Through our Northern Louisiana system, we offer producers and customers wellhead-to-market services. Our Northern Louisiana system has numerous market outlets for the natural gas we gather, including several intrastate and interstate pipelines, major industrial end-users and major power plants. The system is strategically located to facilitate the transportation of natural gas from Texas and northern Louisiana to pipeline connections linking to markets in the eastern areas of the United States.

Our Piceance system is comprised of a 75% operating interest in Collbran Valley Gas Gathering, LLC, or Collbran, and consists of assets in the southern Piceance Basin that gather natural gas at high pressure from over 20,000 dedicated and producing acres in western Colorado. The remaining 25% interest in the joint venture is held by Occidental Petroleum Corporation who is the primary producer on the system.

We have a 40% interest in Discovery Producer Services LLC, or Discovery, with the remaining 60% owned by Williams Partners L.P. The Discovery system is operated by Williams Partners L.P. and offers a full range of wellhead-to-market services to both onshore and offshore natural gas producers. The assets are primarily located in the eastern Gulf of Mexico and Lafourche Parish, Louisiana. We, along with Williams Partners L.P., expanded the Discovery natural gas gathering pipeline system in the deepwater Gulf of Mexico with the Keathley Canyon Connector, a 209-mile subsea natural gas gathering pipeline for production from the Keathley Canyon, Walker Ridge and Green Canyon areas in the central deepwater Gulf of Mexico. The Keathley Canyon Connector was placed into service in the first quarter of 2015. The Keathley Canyon Connector extension is supported by long-term fee-based agreements with the Lucius and Hadrian South owners, as well as the Heidelberg and Hadrian North owners, for natural gas gathering, transportation and processing services for production from those fields. In addition, the new pipeline system is in proximity to other high-potential deepwater Gulf of Mexico discoveries and prospects.

Our Southern Oklahoma system is located in the Golden Trend area of McClain, Garvin and Grady counties in southern Oklahoma. The system is adjacent to assets owned by DCP Midstream, LLC. Natural gas gathered by the system is delivered to DCP Midstream, LLC processing plants.

Our Wyoming system consists of natural gas gathering pipelines that cover more than 4,000 square miles in the Powder River Basin in Wyoming. The system gathers primarily rich casing-head gas from oil wells at low pressure and delivers the gas to a third party for processing under a fee-based agreement.

Natural Gas and NGL Markets

The Eagle Ford system has natural gas residue outlets including interstate and intrastate pipelines. The system delivers NGLs to the Gulf Coast petrochemical markets and to Mont Belvieu through our Sand Hills pipeline, owned approximately one-third each by us, Phillips 66 and Spectra Energy Partners, LP, and other third party NGL pipelines. Our Eagle plant has delivery options into the Trunkline and Transco gas pipeline systems.

The Southeast Texas system has numerous local natural gas market outlets and delivers residue gas into various interstate and intrastate pipelines. The Southeast Texas system also makes NGL market deliveries directly to Exxon Mobil.

The East Texas system delivers gas primarily through its Carthage Hub which delivers residue gas to multiple interstate and intrastate pipelines. Certain of the lighter NGLs, consisting of ethane and propane, are fractionated at the East Texas facility and sold to regional petrochemical purchasers. The remaining NGLs, including butanes and natural gasoline, are purchased by DCP Midstream, LLC and transported to Mont Belvieu for fractionation and sale.

The Michigan system delivers Antrim Shale gas to our four treating plants and the gas is then transported to a third party power plant with connections to several intrastate pipelines.

The Piceance system gathers, compresses and delivers unprocessed gas to a third party natural gas processing plant.

The Northern Louisiana system has numerous market outlets for the natural gas that we gather on the system. In addition, our natural gas pipelines in northern Louisiana have access to gas that flows through numerous pipelines, are connected to major industrial end-users and makes deliveries to various power plants. The NGLs extracted from the natural gas at the Minden processing plant are delivered to our Black Lake NGL pipeline, in our NGL Logistics segment, through our Minden NGL pipeline. The Black Lake NGL pipeline delivers NGLs to Mont Belvieu and other NGL markets.

The Discovery assets have access to downstream pipelines and markets. The NGLs are fractionated, then delivered downstream to third-party purchasers consisting of a mix of local petrochemical facilities and wholesale distribution companies as well as pipelines that transport product to the storage and distribution center near Napoleonville, Louisiana or other similar product hubs.

The Southern Oklahoma system has access to a mix of mid-continent pipelines and markets through DCP Midstream, LLC owned processing plants.

The Wyoming system delivers unprocessed gas to a third party natural gas processing plant. Residue gas and NGLs are delivered to third party and affiliate pipelines.

The DJ Basin system delivers to the Conway hub in Bushton, Kansas via our Wattenberg pipeline and to the Mont Belvieu hub in Mont Belvieu, Texas via the Front Range and Texas Express pipelines in our NGL Logistics segment.

Customers and Contracts

The suppliers of natural gas to our Natural Gas Services segment are a broad cross-section of the natural gas producing community. We actively seek new producing customers of natural gas on all of our systems to increase throughput volume and to offset natural declines in the production from connected wells. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, by connecting new wells drilled on dedicated acreage and by obtaining natural gas that has been directly received or released from other gathering systems.

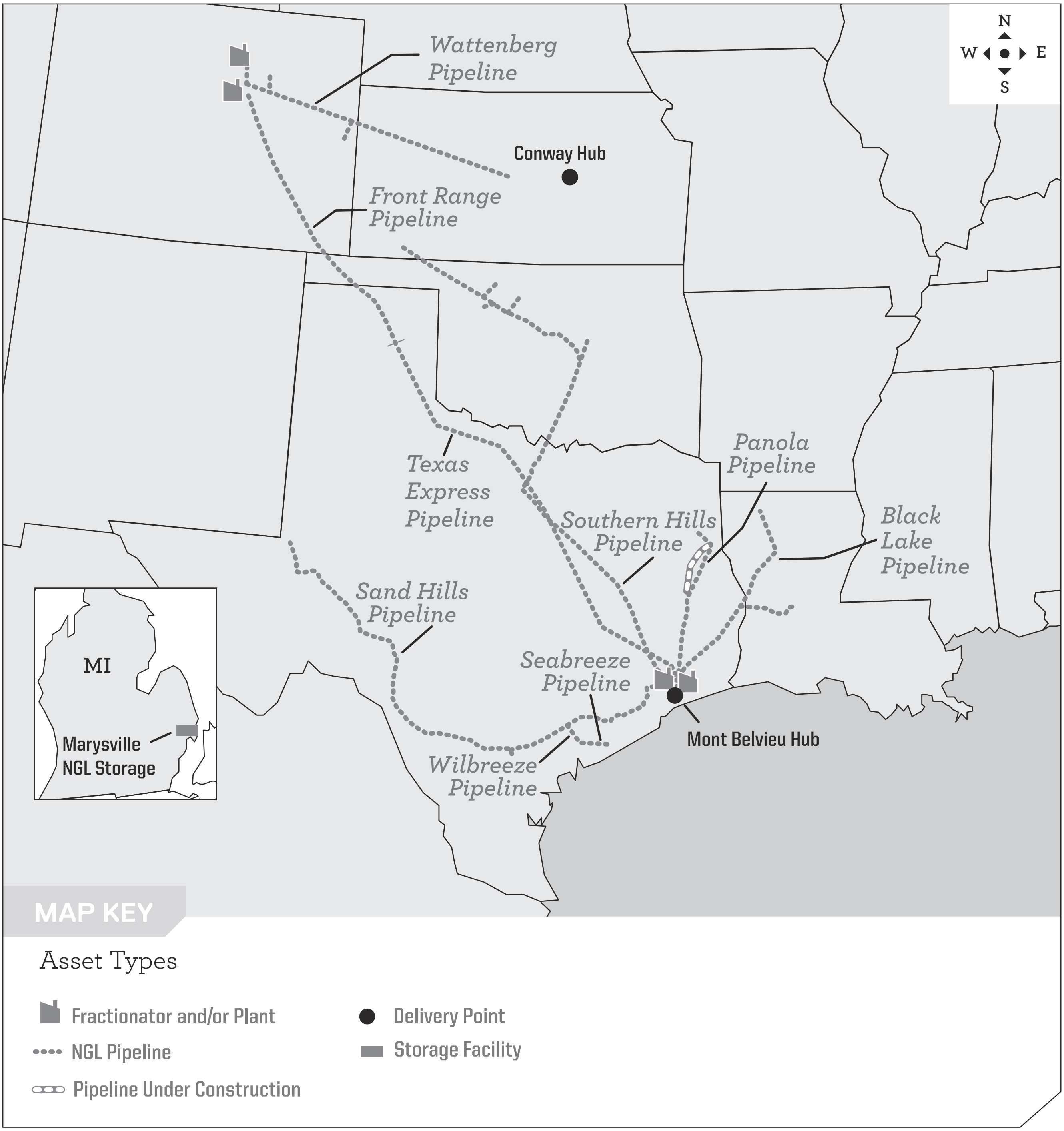
Our contracts with our producing customers in our Natural Gas Services segment are a mix of commodity sensitive percent-of-proceeds and percent-of-liquids contracts and non-commodity sensitive fee-based contracts. Our gross margin generated from percent-of-proceeds contracts is directly related to the price of natural gas, NGLs and condensate and our gross margin generated from percent-of-liquids contracts is directly related to the price of NGLs and condensate. Additionally, these contracts may include fee-based components. Generally, the initial term of these purchase agreements is for three to five years or, in some cases, the life of the lease. The largest percentage of volume at our Southern Oklahoma and Eagle Ford systems are processed under percent-of-proceeds contracts. The producer contracts at our East Texas and Southeast Texas systems are primarily percent-of-liquids. The majority of the contracts for our Piceance, DJ Basin and Michigan systems are fee-based. The DJ Basin system has in place long-term fee-based processing agreement with DCP Midstream, LLC which provides us with a fixed demand charge on a portion of the plants' capacities and a throughput fee on all volumes processed. Our Wyoming system has a combination of percent-of-proceeds and fee-based contracts. Discovery has percent-of-liquids, fee-based and keep-whole contracts. Our Northern Louisiana system has a combination of percent-of-proceeds, keep-whole and fee-based contracts.

Discovery’s 100% owned subsidiary, Discovery Gas Transmission, owns the mainline and the Federal Energy Regulatory Commission, or FERC, regulated laterals, which generate revenues through a tariff on file with FERC for several types of service: traditional firm transportation service with reservation fees; firm transportation service on a commodity basis with reserve dedication; and interruptible transportation service. In addition, for any of these general services, Discovery Gas Transmission has the authority to negotiate a specific rate arrangement with an individual shipper and has several of these arrangements currently in effect.

Competition

The natural gas services business is highly competitive in our markets and includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport, store and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

NGL Logistics Segment



General

We own and operate assets for our NGL Logistics business in the states of Colorado, Kansas, Louisiana, Michigan, Oklahoma and Texas.

Our NGL pipelines transport NGLs from natural gas processing plants to fractionation facilities, a petrochemical plant and a third party underground NGL storage facility. Our pipelines provide transportation services to customers primarily on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to recover NGLs from natural gas because of the higher value of natural gas compared to the value of

NGLs. As a result, we have experienced periods, and will likely experience periods in the future, when higher relative natural gas prices reduce the volume of NGLs produced at plants connected to our NGL pipelines.

Our NGL fractionation facilities in the DJ Basin, in Colorado, and our partially owned facilities in Mont Belvieu, Texas, separate NGLs received from processing plants into their individual components. The fractionation facilities provide services on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of NGLs fractionated and the level of fees charged to customers.

Our NGL storage facility is located in Marysville, Michigan with strategic access to Canadian NGLs. Our facility serves regional refining and petrochemical demand, and helps to balance the seasonality of propane distribution in the midwestern and northeastern United States and in Sarnia, Canada. We provide services to customers primarily on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product injected, stored and withdrawn, and the level of fees charged to customers.

The following is operating data for our NGL Logistics segment:

2014 Operating Data

System	Ownership Interest	Approximate System Length (Miles)	Fractionators	Approximate Throughput Capacity (MBbls/d) (a)	Approximate NGL Storage Capacity (MMBbls) (a)	Pipeline Throughput (MBbls/d) (a)	Fractionator Throughput (MBbls/d) (a)
Sand Hills pipeline	33.33%	1,025	—	67	—	37	—
Southern Hills pipeline	33.33%	940	—	58	—	19	—
Texas Express pipeline (b)	10%	583	—	28	—	10	—
Wattenberg pipeline	100%	500	—	22	—	19	—
Front Range pipeline (b)	33.33%	450	—	50	—	14	—
Black Lake pipeline	100%	317	—	40	—	34	—
Panola pipeline (b)	15%	180	—	8	—	(c)	—
Seabreeze pipeline	100%	56	—	41	—	24	—
Wilbreeze pipeline	100%	39	—	11	—	26	—
Other pipeline	100%	25	—	10	—	2	—
Mont Belvieu Enterprise fractionator (b)	12.5%	—	1	28	—	—	28
Mont Belvieu 1 fractionator (b)	20%	—	1	32	—	—	21
DJ Basin fractionators	100%	—	2	15	—	—	12
Marysville storage facility	100%	—	—	—	8	—	—
Total		4,115	4	410	8	185	61

(a) Represents total capacity or throughput allocated to our proportionate ownership share for 2014 divided by 365 days.
(b) Represents an asset operated by a third party.
(c) We acquired our interest in the Panola pipeline in January 2015.

NGL Pipelines

DCP Southern Hills Pipeline, LLC, or the Southern Hills pipeline, an intrastate NGL pipeline in which we own a 33.33% interest, provides takeaway service from the Midcontinent to fractionation facilities at the Mont Belvieu, Texas market hub. DCP Midstream, LLC is the operator of the pipeline.

DCP Sand Hills Pipeline, LLC, or the Sand Hills pipeline, an interstate NGL pipeline in which we own a 33.33% interest, is a common carrier pipeline which provides takeaway service from plants in the Permian and the Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and at the Mont Belvieu, Texas market hub. DCP Midstream, LLC is the operator of the pipeline.

Texas Express Pipeline LLC, or the Texas Express pipeline, an intrastate NGL pipeline in which we own a 10% interest, originates near Skellytown in Carson County, Texas, and extends to Enterprise Products Partners L.P.'s, or Enterprise, natural gas liquids fractionation and storage complex at Mont Belvieu, Texas. The pipeline also provides access to other third party facilities in the area. Enterprise is the operator of the pipeline.

The Wattenberg interstate NGL pipeline originates in the DJ Basin in Colorado and terminates near the Conway hub in Bushton, Kansas. The pipeline is currently connected to DCP Midstream, LLC plants and our O'Connor plant in the DJ Basin.

Front Range Pipeline LLC, or the Front Range pipeline, an interstate NGL pipeline in which we own a 33.33% interest, is a raw NGL mix pipeline that originates in the DJ Basin and extends to Skellytown, Texas. The Front Range pipeline connects to the O'Connor plant as well as third party and DCP Midstream, LLC plants in the DJ Basin. Enterprise is the operator of the pipeline, which was placed into service in February 2014.

The Black Lake interstate NGL pipeline originates in northwestern Louisiana and terminates in Mont Belvieu, Texas. Black Lake receives NGLs from gas processing plants in northwestern Louisiana and southeastern Texas, including our Northern Louisiana system and multiple third party plants, the Sand Hills pipeline and a third party storage facility. Black Lake delivers the NGLs it receives from these sources to fractionation plants in Mont Belvieu, Texas including our partially owned Enterprise and Mont Belvieu 1 fractionators.

Panola Pipeline Company, LLC, or the Panola pipeline, an intrastate NGL pipeline in which we own a 15% interest, is an approximately 180-mile NGL pipeline system extending from points near Carthage, Texas to Mont Belvieu, Texas. We acquired our interest in the pipeline in January 2015. The pipeline supports the Haynesville and Cotton Valley oil and gas production areas. The pipeline is currently undergoing a 60-mile expansion to Lukin, Texas, as well as construction of two additional pump stations, which are expected to be completed in the first quarter of 2016. Enterprise is the operator of the pipeline.

The Seabreeze intrastate NGL pipeline is located in Matagorda, Jackson and Calhoun Counties, Texas. The Seabreeze pipeline receives NGLs from the Wilbreeze NGL pipeline and a third party plant and pipeline. The Seabreeze pipeline delivers the NGLs it receives from these sources to a third party fractionator, its associated storage facility, and a third party pipeline.

The Wilbreeze intrastate NGL pipeline is located in Lavaca and Jackson Counties, Texas. The Wilbreeze pipeline receives NGLs from the Eagle Ford system, the Sand Hills pipeline, as well as a third party plant, and delivers the NGLs it receives from these sources to the Seabreeze pipeline and Enterprise’s Eagle pipeline.

NGL Fractionation Facilities

We hold a 12.5% interest in the Enterprise fractionator operated by Enterprise and a 20% interest in the Mont Belvieu 1 fractionator operated by ONEOK Partners, both located in Mont Belvieu, Texas.

Our DJ Basin NGL fractionators in Colorado are located on DCP Midstream, LLC’s processing plant sites and are operated by DCP Midstream, LLC, which delivers NGLs to the fractionators under a long-term fractionation agreement.

NGL Storage Facility

Our NGL storage facility is located in Marysville, Michigan and includes 10 underground salt caverns with approximately 8 MMBbls of storage capacity and rail, truck and pipeline connections providing an important supply point for refiners, petrochemical plants and wholesale propane distributors in the Sarnia, midwestern and northeastern markets.

Customers and Contracts

Our contracts with our customers in our NGL Logistics segment are primarily non-commodity sensitive fee-based contracts.

The Southern Hills, Sand Hills, Texas Express, and Front Range pipelines have long-term, fee-based, ship-or-pay transportation agreements in place with affiliates of DCP Midstream, LLC as well as third party shippers.

The Wattenberg pipeline is an open access pipeline with access to numerous gas processing facilities in the DJ Basin. The Wattenberg pipeline is supported by a long-term dedication and transportation agreement with a subsidiary of DCP Midstream, LLC whereby certain NGL volumes produced at several of DCP Midstream, LLC’s processing facilities are dedicated for transportation on the Wattenberg pipeline. We collect fee-based transportation revenue under our tariff.

DCP Midstream, LLC has historically been the largest active shipper on the Black Lake pipeline, accounting for approximately 52% of total throughput in 2014. The Black Lake pipeline generates revenue primarily through a FERC-regulated tariff.

DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a long-term transportation agreement. The Seabreeze pipeline collects fee-based transportation revenue under this agreement.

The Wilbreeze pipeline is supported by an NGL product dedication agreement with DCP Midstream, LLC.

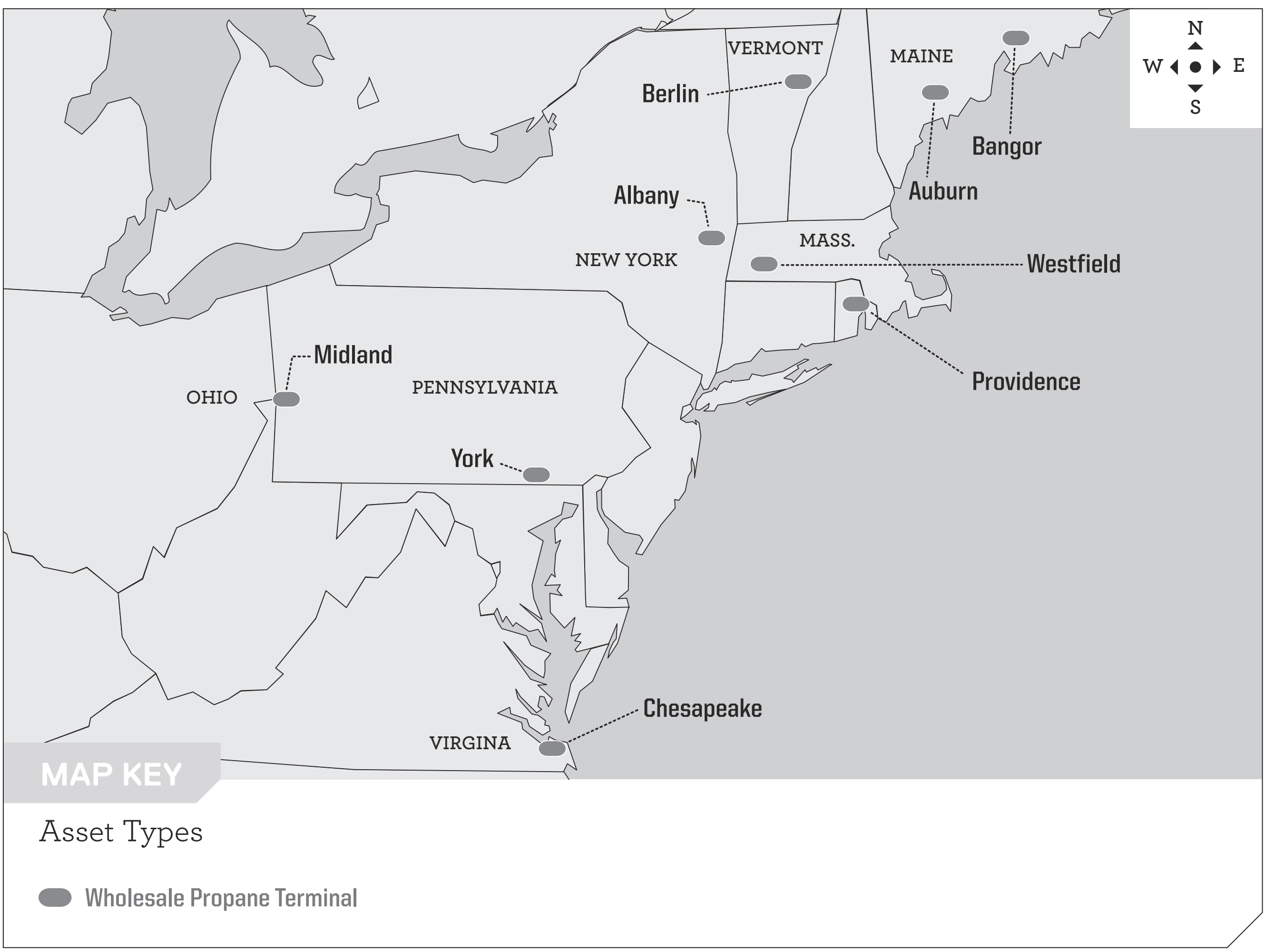
Our Marysville NGL storage facility serves retail and wholesale propane customers, as well as refining and petrochemical customers, under one to three-year term storage agreements. Our revenues for this facility are primarily fee-based.

DCP Midstream, LLC supplies certain committed NGLs to our DJ Basin NGL fractionators under fee-based agreements that are effective through March 2018.

Competition

The NGL logistics business is highly competitive in our markets and includes interstate and intrastate pipelines, integrated oil and gas companies that produce, fractionate, transport, store and sell NGLs, and underground storage facilities. Competition is often the greatest in geographic areas experiencing robust drilling by producers and strong petrochemical demand and during periods of high NGL prices relative to natural gas. Competition is also increased in those geographic areas where our contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

Wholesale Propane Logistics Segment



General

We own or operate assets for our wholesale propane logistics business in the states of Maine, Massachusetts, New York, Pennsylvania, Rhode Island, Vermont and Virginia. Our operations serve the large propane and other liquefied petroleum gas markets in the northeastern, mid-Atlantic, and upper midwestern states.

Due to our multiple propane supply sources, annual and long-term propane supply purchase arrangements, storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our propane distribution customers with reliable, low cost deliveries and greater volumes of propane during periods of tight supply such as the winter months. We may also provide storage services to our customers for propane and other liquefied petroleum gases. We believe these factors generally result in our maintaining favorable relationships with our customers and allowing us to remain a supplier to many of the large distributors in the northeastern and mid-Atlantic United States. As a result, we serve as the baseload provider of propane supply to many of our propane distribution customers.

Pipeline deliveries to the northeastern and mid-Atlantic markets in the winter season are generally at capacity and competing pipeline-dependent terminals can have supply constraints or outages during peak market conditions. Our system of terminals has excess capacity, which provides us with opportunities to increase our volumes with minimal additional cost.

Our Terminals

Our operations include one owned and one leased propane marine terminal, one owned propane pipeline terminal and six owned propane rail terminals, with a combined capacity of approximately 975 MBbls, and access to several open access pipeline terminals. Our owned marine terminal also has storage capabilities for other liquefied petroleum gases. We own our rail terminals and lease the land on which the terminals are situated under long-term leases, except for the York terminal where we own the land. The lease agreement for our leased marine terminal expires in March 2015. Each of our rail terminals consist of two to three propane tanks that provide additional capacity for storage, and two high volume racks for loading propane into trucks. Each truck can be fully loaded within 15 minutes, providing for an aggregate truck-loading capacity of approximately 400 trucks per day. Each facility also has the ability to unload multiple railcars simultaneously. We have numerous railcar leases that allow us to increase our storage and throughput capacity as propane demand increases.

Propane Supply

Our wholesale propane business has a strategic network of supply arrangements under annual and multi-year agreements with index-based pricing. The remaining supply is purchased on month-to-month terms to match our anticipated sale requirements. Our primary suppliers of propane include a subsidiary of DCP Midstream, LLC, MarkWest, BP Canada and Petredec Limited. We may also obtain supply from our NGL storage facility in Marysville, Michigan.

For our rail terminals, we contract for propane at various major supply points in the United States and Canada, and transport the product to our terminals under long-term rail commitments, which provide fixed transportation costs that are subject to prevailing fuel surcharges. We also purchase propane supply from natural gas fractionation plants and crude oil refineries located in the Texas and Louisiana Gulf Coast. Through this process, we take custody of the propane and either sell it in the wholesale market or store it at our facilities.

Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may periodically recognize non-cash lower of cost or market inventory adjustments, which occur when the market value of our commodities declines below our carrying value.

Customers and Contracts

We typically sell propane to propane distributors under annual sales agreements, negotiated each spring, that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a propane distributor desires to purchase propane from us on a fixed price basis, we may enter into fixed price sales agreements with terms of generally up to one year. We manage this commodity price risk by purchasing and storing propane, by entering into physical purchase agreements or by entering into offsetting financial derivative instruments, with DCP Midstream, LLC or third parties, that generally match the quantities of propane subject to these fixed price sales agreements. Our ability to help our clients manage their commodity price exposure by offering propane at a fixed price may lead to improved margins and a larger customer base. We provide storage services for other liquefied petroleum gases on a fee basis under a multi-year agreement. Historically, the majority of the gross margin generated by our wholesale propane business is earned in the heating season months of October through April, which corresponds to the general market demand for propane.

We had two third-party customers in our Wholesale Propane segment that accounted for greater than 10% of our segment revenues for the year ended December 31, 2014.

Competition

The wholesale propane business is highly competitive in the mid-Atlantic, upper midwestern and northeastern regions of the United States. Our wholesale propane business' competitors include integrated oil and gas and energy companies, interstate and intrastate pipelines, as well as marketers and other wholesalers.

Other Segment Information

For additional information on our segments, please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Note 18 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

We have no revenue attributable to international activities.

REGULATORY AND ENVIRONMENTAL MATTERS

Safety and Maintenance Regulation

We are subject to regulation by the United States Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, or HLPSA, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations.

We are also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, or NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines in high-consequence areas within 10 years. DOT, through the Pipeline and Hazardous Materials Safety Administration (PHMSA), has developed regulations implementing the Pipeline Safety Improvement Act that requires pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

Pipeline safety legislation enacted in 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, (the Pipeline Safety and Job Creations Act) reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. New rules proposed by DOT's PHMSA address many areas of this legislation. Extending the integrity management requirements to our gathering lines would impose additional obligations on us and could add material cost to our operations.

The Pipeline Safety and Job Creation Act requires more stringent oversight of pipelines and increased civil penalties for violations of pipeline safety rules. The legislation gives PHMSA civil penalty authority up to $200,000 per day, with a maximum of $2 million for any related series of violations. Any material penalties or fines under these or other statues, rules, regulations or orders could have a material adverse impact on our business, financial condition, results of operation and cash flows.

We currently estimate we will incur between $4 million and $6 million between 2015 and 2019 to implement integrity management program testing along certain segments of our natural gas transmission and NGL pipelines. We believe that we are in compliance in all material respects with the NGPSA and the Pipeline Safety Improvement Act of 2002 and the Pipeline Safety and Job Creation Act.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we or the entities in which we own an interest operate. Our natural gas transmission and regulated gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management and EPA Risk Management Program regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. The OSHA regulations apply to any process which involves a chemical at or above specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt from these standards. The EPA regulations have similar applicability thresholds. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in compliance in all material respects with all applicable laws and regulations relating to worker health and safety.

Propane Regulation

National Fire Protection Association Codes 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. The transportation of propane by rail is regulated by the Federal Railroad Administration. 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.

FERC Regulation of Operations

FERC regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Interstate Natural Gas Pipeline Regulation

The Discovery 105-mile mainline, approximately 60 miles of laterals and its market expansion project are subject to regulation by FERC, under the Natural Gas Act of 1938, as amended, or NGA. Natural gas companies may not charge rates that have been determined to be unjust or unreasonable. In addition, FERC authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- terms and conditions of services and service contracts with customers;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates; and
- various other matters.

Generally, the maximum filed recourse rates for interstate pipelines are based on the cost of service including recovery of and a return on the pipeline's actual prudent investment cost. Key determinants in the ratemaking process are costs of providing service, allowed rate of return and volume throughput and contractual capacity commitment assumptions. The maximum applicable recourse rates and terms and conditions for service are set forth in each pipeline's FERC-approved gas tariff. Rate design and the allocation of costs also can impact a pipeline's profitability. FERC-regulated natural gas pipelines are permitted to discount their firm and interruptible rates without further FERC authorization down to the minimum rate or variable cost of performing service, provided they do not "unduly discriminate."

Tariff changes can only be implemented upon approval by FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If FERC determines, as required by the NGA, that a proposed change is just and reasonable, FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, if FERC determines that a proposed change may not be just and reasonable as required by NGA, then FERC may suspend such change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. Subsequent to any suspension period ordered by FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, FERC may, on its own motion or based on a complaint, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by FERC and Congress, especially in light of potential market power abuse by marketing affiliates of certain pipeline companies engaged in interstate commerce. In response to this issue, Congress, in the Energy Policy Act of 2005, or EPACT 2005, and FERC have implemented requirements to ensure that energy prices are not impacted by the exercise of market power or manipulative conduct. EPACT 2005 prohibits the use of any "manipulative or deceptive device or contrivance" in connection with the purchase or sale of natural gas, electric energy or transportation subject to FERC jurisdiction. In addition, EPACT 2005 gave FERC increased penalty authority for these violations. FERC may now issue civil penalties of up to $1 million per day per violation, and possible criminal penalties of up to $1 million per violation and five years in prison. FERC may also order disgorgement of profits obtained in violation of FERC rules. FERC adopted the Market Manipulation Rules and the Market Behavior Rules to implement the authority granted under EPACT 2005. These rules, which prohibit fraud and manipulation in wholesale energy markets, are subject to broad interpretation. In the past two years, FERC has relied on its EPACT 2005 enforcement authority in issuing a number of natural gas enforcement actions giving rise to the imposition of aggregate penalties of approximately $1 million and aggregate disgorgements of approximately $10 million. In addition, during 2014, FERC commenced a natural gas enforcement action against a third party involving a proposed penalty of $28 million and disgorgements of $800,000, which is pending litigation and resolution at FERC. These orders reflect FERC's view that it has broad latitude in determining whether specific behavior violates the rules. Given FERC's broad mandate granted in EPACT 2005, if energy prices are high, or exhibit what FERC deems to be "unusual" trading patterns, FERC will investigate energy markets to determine if behavior unduly impacted or "manipulated" energy prices.

Intrastate Natural Gas Pipeline Regulation

Intrastate natural gas pipeline operations are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate gas pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases. However, to the extent that an intrastate pipeline system transports natural gas in interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. Under Section 311, intrastate pipelines providing interstate service may avoid jurisdiction that would otherwise apply under the NGA. Section 311 regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by FERC at least once every five years. The rate review may, but does not necessarily, involve an administrative-type hearing before FERC staff panel and an administrative appellate review. Additionally, the terms and conditions of service set forth in the intrastate pipeline's Statement of Operating Conditions are subject to FERC approval. Failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved Statement of Operating Conditions could result in the assertion of federal NGA jurisdiction by FERC and/or the imposition of administrative, civil and criminal penalties. Among other matters, EPACT 2005 amends the NGPA to give FERC authority to impose civil penalties for violations of the NGPA up to $1 million per day per violation and possible criminal penalties of up to $1 million per violation and five years in prison for violations occurring after August 8, 2005. The Pelico, Cipco and EasTrans (part of our East Texas system) systems are subject to FERC jurisdiction under Section 311 of the NGPA.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We believe that our natural gas gathering facilities meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services continues to be a current issue in various FERC proceedings with respect to facilities that interconnect gathering and processing plants with nearby interstate pipelines, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

Our purchasing, gathering and intrastate transportation operations are subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase 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. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels where FERC has recognized a jurisdictional exemption for the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. 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. 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.

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission, or CFTC. Should we violate the anti-market manipulation laws and regulations, we could be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations.

Interstate NGL Pipeline Regulation

The Sand Hills, Southern Hills, Black Lake, Wattenberg and Front Range pipelines are interstate NGL pipelines subject to FERC regulation. FERC regulates interstate NGL pipelines under its Oil Pipeline Regulations, the Interstate Commerce Act of 1887, as amended, or ICA, and the Elkins Act of 1903, as amended. FERC requires that interstate NGL pipelines file tariffs containing all the rates, charges and other terms for services performed. The ICA requires that tariffs apply to the interstate movement of NGLs, as is the case with the Sand Hills, Southern Hills, Black Lake, Wattenberg and Front Range pipelines. Pursuant to the ICA, rates can be challenged at FERC either by protest when they are initially filed or increased or by complaint at any time they remain on file with FERC.

In October 1992, Congress passed EPACT, which among other things, required FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for pipelines regulated by FERC pursuant to the ICA. FERC responded to this mandate by issuing several orders, including Order No. 561. Beginning January 1, 1995, Order No. 561 enables petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. Specifically, the indexing methodology allows a pipeline to increase its rates annually by a percentage equal to the change in the producer price index for finished goods, PPI-FG, plus 2.65% to the new ceiling level. Rate increases made pursuant to the indexing methodology are subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the PPI-FG falls and the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling unless doing so would reduce a rate "grandfathered" by EPACT (see below) below the grandfathered level. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. FERC, however, retained cost-of-service ratemaking, market-based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. FERC's indexing methodology is subject to review every five years; the current methodology remains in place through June 30, 2016.

EPACT deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPACT that had not been subject to complaint, protest or investigation during that 365-day period to be just and reasonable under the ICA. Generally, complaints against such "grandfathered" rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPACT in either the economic circumstances of the petroleum pipeline, or in the nature of the services provided, that were a basis for the rate. EPACT places no such limit on challenges to a provision of a petroleum pipeline tariff as unduly discriminatory or preferential.

Intrastate NGL Pipeline Regulation

Intrastate NGL and other petroleum pipelines are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for gathering, compressing, treating, processing, transporting, fractionating, storing or selling natural gas, NGLs and other products is subject to stringent and complex federal, state and local laws and regulations governing the emission or discharge of materials into the environment or otherwise relating to the protection of the environment.

As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the acquisition of permits to conduct regulated activities and imposing obligations in those permits that reduce or limit impacts to the environment;
- restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining, or compelling changes to, the operations of facilities deemed not to be in compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining or affecting future operations. Certain environmental statutes impose strict liability or joint and several liability for costs required to clean up and restore sites where hazardous substances, or in some cases hydrocarbons, have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for property damage or possibly personal injury allegedly caused by the release of substances or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations, participate as applicable in the public process to ensure such new requirements are well founded and reasonable or to revise them if they are not, and to manage the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. Below is a discussion of the more significant environmental laws and regulations that relate to our business.

Impact of Climate Change and Air Quality Standards

A number of states have adopted or considered programs to reduce "greenhouse gases," or GHGs, and depending on the particular program or jurisdiction, we could be required to purchase and surrender allowances, either for GHG emissions resulting from our operations (e.g., compressor units) or from combustion of fuels (e.g., oil or natural gas) that we process. Also, the EPA has declared that GHGs "endanger" public health and welfare, and is regulating GHG emissions from mobile sources such as cars and trucks. According to the EPA, this final action on the GHG vehicle emission rule triggered regulation of carbon dioxide and other GHG emissions from stationary sources under certain Clean Air Act programs at both the federal and state levels, particularly the Prevention of Significant Deterioration program and Title V permitting. These requirements for stationary sources took effect on January 2, 2011; however, in June 2014 the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals decision upholding these rules and struck down the EPA's greenhouse gas permitting rules to the extent they impose a requirement to obtain a federal air permit based solely on emissions of greenhouse gases. Large sources of other air pollutants, such as volatile organic compounds or nitrogen oxides, could still be required to implement process or technology controls and obtain permits regarding emissions of greenhouse gases. The EPA has also published various rules relating to the mandatory reporting of GHG emissions, including mandatory reporting requirements of GHGs from petroleum and natural gas systems. In December 2014, the EPA proposed to amend and expand greenhouse gas reporting requirements to all segments of the oil and gas sector, with a final regulation expected to be effective by January 2016. In January 2015, the EPA announced that it would issue proposed new source performance standards for methane (a greenhouse gas) from new and modified oil and gas sector sources and finalize those standards in 2016. The EPA also indicated that it would issue Control Technology Guidelines for emissions of volatile organic compounds from oil and gas sector sources to be implemented or utilized by states in ozone nonattainment areas, with an expected co-benefit of reduced methane emissions, and in November 2014, proposed to reduce the ambient ozone standard from 75 parts per billion to between 65 and 70 parts per billion under the Clean Air Act by October 2015. The permitting, regulatory compliance and reporting programs taken as a whole increase the costs and complexity of operating oil and gas operations in compliance with these legal requirements, with resulting potential to adversely affect our cost of doing business, demand for the oil and gas we transport and may require us to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances or solid wastes, including petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste, and may impose strict liability or joint and several liability for the investigation and remediation of areas at a facility where hazardous substances, or in some cases hydrocarbons, may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible parties the costs the agency incurs. Despite the "petroleum exclusion" of CERCLA Section 101(14) that currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate solid wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as hazardous wastes and therefore be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease properties where petroleum hydrocarbons are being or have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these petroleum hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties may have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws or state laws that address hydrocarbon releases. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to the application of such requirements that could reasonably have a material impact on our operations or financial condition.

Water

The Federal Water Pollution Control Act of 1972, as amended, also referred to as the Clean Water Act, or CWA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state and federal waters. The CWA also requires implementation of spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of threshold quantities of oil. The CWA imposes substantial potential civil and criminal penalties for non-compliance. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater. The EPA has promulgated regulations that require us to have permits in order to discharge certain storm water. The EPA has entered into agreements with certain states in which we operate whereby the permits are issued and administered by the respective states. These permits may require us to monitor and sample the storm water discharges. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

The Oil Pollution Act of 1990, or OPA, addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities, including terminals, pipelines, and transfer facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages, and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in government penalties and civil liability. We are not currently aware of any facts, events or conditions relating to the application of such requirements that could reasonably have a material impact on our operations or financial condition.

Anti-Terrorism Measures

The federal Department of Homeland Security regulates the security of chemical and industrial facilities pursuant to regulations known as the Chemical Facility Anti-Terrorism Standards. These regulations apply to oil and gas facilities, among others, that are deemed to present "high levels of security risk." Pursuant to these regulations, certain of our facilities are required to comply with certain regulatory provisions, including requirements regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

Employees

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, or the General Partner, which is 100% owned by DCP Midstream, LLC. As of December 31, 2014, the General Partner or its affiliates employed 4 people directly and 649 people who provided direct support for our operations through DCP Midstream, LLC. Our executive management personnel are employees of DCP Midstream, LLC. In 2015, our chief executive officer and group vice president and chief financial officer are expected to devote approximately 40% of their time to our matters. Other executive management, including William S. Waldheim, our President, is expected to devote substantially all of his time to our matters, and Michael S. Richards, our Vice President, General Counsel and Secretary, is expected to devote approximately 75% of his time to our matters. See additional discussion in Item 10. "Directors, Executive Officers and Corporate Governance".

General

We make certain filings with the Securities and Exchange Commission, or SEC, including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports, which are available free of charge through our website, *www.dcppartners.com*, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the internet at *www.sec.gov*. Our annual reports to unitholders, press releases and recent analyst presentations are also available on our website. We have also posted our code of business ethics on our website.

Item 1A. *Risk Factors*

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. You should consider carefully the following risk factors together with all of the other information included in this annual report in evaluating an investment in our common units.

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment.

Risks Related to Our Business

Our cash flow is affected by natural gas, NGL and condensate prices.

Our business is affected by the level of natural gas, NGL and condensate prices. NGL and condensate prices generally fluctuate on a basis that relates to fluctuations in crude oil prices. In the past, the prices of natural gas and crude oil have been volatile, and we expect this volatility to continue. Prices of both commodities have seen recent significant declines.

The level of drilling activity is dependent on economic and business factors beyond our control. Among the factors that impact drilling decisions are commodity prices, the liquids content of the natural gas production, drilling requirements for producers to hold leases, the cost of finding and producing natural gas and crude oil and the general condition of the financial markets. Commodity prices have recently declined substantially and experienced significant volatility during the latter part of 2014, as illustrated by the following table:

	Year Ended December 31, 2014		Average For The Month Ended December 31, 2014
	Daily High	Daily Low	
Commodity:			
NYMEX Natural Gas ($/MMBtu)	$ 6.15	$ 2.89	$ 3.51
NGLs ($/Gallon)	$ 1.27	$ 0.45	$ 0.51
Crude Oil ($/Bbl)	$ 107.26	$ 53.27	$ 59.29

Crude oil prices have declined further in 2015 and natural gas liquids prices have softened in relation to crude prices. Natural gas and natural gas liquids prices are currently below levels seen in recent years due to increased supplies and higher inventory levels. If commodity prices remain weak for a sustained period, our natural gas throughput and NGL volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area, but in general, we have observed decreases in drilling activity with lower commodity prices.

Furthermore, a sustained decline in commodity prices could result in a decrease in exploration and development activities in the fields served by our gas gathering and residue gas and NGL pipeline transportation systems, and our natural gas treating and processing plants, which could lead to reduced utilization of these assets. During periods of natural gas price decline and/or if the price of NGLs and crude oil continues to decline, the level of drilling activity could decrease. When combined with a reduction of cash flow resulting from lower commodity prices, a reduction in our producers' borrowing base under reserve-based credit facilities and lack of availability of debt or equity financing for our producers may result in a significant reduction in our producers' spending for crude oil and natural gas drilling activity, which could result in lower volumes being transported on our pipeline systems. Other factors that impact production decisions include the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Because of these factors, even if new 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 natural gas to replace the declines resulting from reductions in drilling activity, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows and our ability to make cash distributions.

Market conditions, including commodity prices, may impact our earnings and cash flows.

The markets and prices for natural gas, NGLs, condensate and crude oil depend upon factors beyond our control and may not always have a close relationship. These factors include supply of and demand for these commodities, which fluctuate with changes in domestic and export markets and economic conditions and other factors, including:

- the level of domestic and offshore production;
- the availability of natural gas, NGLs and crude oil and the demand in the U.S. and globally for these commodities;
- a general downturn in economic conditions;
- the impact of weather, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively, or extreme weather that may disrupt our operations or related upstream or downstream operations;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems and condensate and NGL export facilities;
- the availability and marketing of competitive fuels; and
- the extent of governmental regulation and taxation.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. Under percent-of-proceeds arrangements, we generally purchase natural gas from producers for an agreed percentage of the proceeds from the sale of residue gas and/or NGLs resulting from our processing activities, and then sell the resulting residue gas and NGLs at market prices. Under these types of arrangements, our revenues and our cash flows increase or decrease, whichever is applicable, as the price of natural gas and NGLs fluctuate.

Our NGL pipelines could be adversely affected by any decrease in NGL prices relative to the price of natural gas.

The profitability of our NGL pipelines is dependent on the level of production of NGLs from processing plants. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost (principally that of natural gas as a feedstock and fuel) of separating the NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce the volume of natural gas processed at plants connected to our NGL pipelines, as well as reducing the amount of NGL extraction, which would reduce the volumes and gross margins attributable to our NGL pipelines and NGL storage facilities.

Our hedging activities and the application of fair value measurements may have a material adverse effect on our earnings, profitability, cash flows, liquidity and financial condition.

We are exposed to risks associated with fluctuations in commodity prices. The extent of our commodity price risk is related largely to the effectiveness and scope of our hedging activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. To mitigate a portion of our cash flow exposure to fluctuations in the price of natural gas and NGLs, we have entered into derivative financial instruments relating to the future price of natural gas and NGLs, as well as crude oil. If the price relationship between NGLs and crude oil declines, our commodity price risk will increase. Furthermore, we have entered into derivative transactions related to only a portion of the volume of our expected natural gas supply and production of NGLs and condensate from our processing plants; as a result, we will continue to have direct commodity price risk to the open portion. Our actual future production may be significantly higher or lower than we estimate at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimate, we will have greater commodity price risk 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 satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, reducing our liquidity.

We record all of our derivative financial instruments at fair value on our balance sheets primarily using information readily observable within the marketplace. In situations where market observable information is not available, we may use a variety of data points that are market observable, or in certain instances, develop our own expectation of fair value. We will continue to use market observable information as the basis for our fair value calculations; however, there is no assurance that such information will continue to be available in the future. In such instances, we may be required to exercise a higher level of judgment in developing our own expectation of fair value, which may be significantly different from the historical fair values, and may increase the volatility of our earnings.

We will continue to evaluate whether to enter into any new derivative arrangements, but there can be no assurance that we will enter into any new derivative arrangement or that our future derivative arrangements will be on terms similar to our existing derivative arrangements. We have entered into fixed price derivative instruments primarily with DCP Midstream, LLC, whereby DCP Midstream, LLC is the counterparty. A sustained decline or continued weakness in commodity prices, further lowering of DCP Midstream, LLC's or our credit ratings, could lessen our ability to enter into new derivative arrangements under acceptable terms, thereby impacting the ability to execute our long-term hedging strategy. Additionally, although we enter into derivative instruments to mitigate a portion of our commodity price and interest rate risk, we also forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

The third party counterparties to our derivative instruments may require us to post collateral in the event that our potential payment exposure exceeds a predetermined collateral threshold. Depending on the movement in commodity prices, the amount of collateral posted may increase, reducing our liquidity.

Our hedging activities may not be as effective as we intend and may actually increase the volatility of our earnings and cash flows. In addition, even though our management monitors our hedging activities, these activities can result in material losses. Such losses could occur under various circumstances, including if a counterparty does not or is unable to perform its obligations under the applicable derivative arrangement, the derivative arrangement is imperfect or ineffective, or our risk management policies and procedures are not properly followed or do not work as planned.

We could incur losses due to impairment in the carrying value of our goodwill or long-lived assets.

We periodically evaluate goodwill and long-lived assets for impairment. Our impairment analyses for long-lived assets require management to apply judgment in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. To perform the impairment assessment for goodwill, we primarily use a discounted cash flow analysis, supplemented by a market approach analysis. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to impairment charges. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect our results of operations and financial condition.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services.

Volumes of natural gas dedicated to our systems in the future may be less than we anticipate.

If the reserves connected to our gathering systems are less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas on our systems in the future could be less than we anticipate.

We depend on certain natural gas producer customers for a significant portion of our supply of natural gas and NGLs.

We identify as primary natural gas suppliers those suppliers individually representing 10% or more of our total natural gas supply. We had one natural gas supplier representing 10% or more of our total natural gas supply during the year ended December 31, 2014. In our NGL Logistics segment, our largest NGL supplier is DCP Midstream, LLC, who obtains NGLs from various third- party producer customers. While some of these customers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts on favorable terms, if at all. The loss of all or even a portion of the natural gas and NGL volumes supplied by these customers, as a result of competition or otherwise, could have a material adverse effect on our business.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of supplies of natural gas and NGLs.

Our gathering and transportation pipeline systems are connected to or dependent on the level of production from natural gas and crude wells, from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and NGL pipelines and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and NGLs, and to attract new customers to our assets include the level of successful drilling activity near these assets, the demand for natural gas, crude oil and NGLs, producers' desire and ability to obtain necessary permits in an efficient manner, natural gas field characteristics and production performance, surface access and infrastructure issues, and our ability to compete for volumes from successful new wells. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells or because of competition, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows, and our ability to make cash distributions.

Third party pipelines and other facilities interconnected to our natural gas and NGL pipelines and facilities may become unavailable to transport, process or produce natural gas and NGLs.

We depend upon third party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. Since we do not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our control and may become unavailable to transport, process or produce natural gas and NGLs.

We may not successfully balance our purchases and sales of natural gas and propane.

We purchase from producers and other customers a substantial amount of the natural gas that flows through our natural gas gathering, processing and transportation systems for resale to third parties, including natural gas marketers and end-users. In addition, in our wholesale propane logistics business, we purchase propane from a variety of sources and resell the propane to distributors. We may not be successful in balancing our purchases and sales. A producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales to be unbalanced. While we attempt to balance our purchases and sales, if our purchases and sales are unbalanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income and cash flows.

Our ability to manage and grow our business effectively could be adversely affected if we or DCP Midstream, LLC fail to attract and retain key management personnel and skilled employees.

We rely on our and DCP Midstream, LLC's executive management team to manage our day-to-day affairs and establish and execute our strategic business and operational plans. This executive management team has significant experience in the midstream energy industry. The loss of any of our or DCP Midstream, LLC's executives or failure to fill new positions created by expansion, turnover or retirement could adversely affect our ability to implement our business strategy. In addition, our operations require engineers, operational and field technicians and other highly skilled employees. Competition for experienced executives and skilled employees is intense and increases when the demand from other energy companies for such personnel is high. Our ability to execute on our business strategy and to grow or continue our level of service to our current customers may be impaired and our business may be adversely impacted if we or DCP Midstream, LLC are unable to attract, train and retain such personnel, which may have an adverse effect on our results of operations and ability to make cash distributions.

A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and independent third parties determine our credit ratings outside of our control.

The recent lowering of our credit rating below investment grade level will increase our cost of borrowing under our Amended and Restated Credit Agreement and could require us to post collateral with third parties, including our hedging arrangements, which could negatively impact our available liquidity and increase our cost of debt. As a result of this ratings action, we no longer have access to the Commercial Paper Program. Our available liquidity under the Commercial Paper Program will be replaced with borrowings under our Amended and Restated Credit Agreement. Additionally, as a result of this ratings action, interest rates and fees under our Amended and Restated Credit Agreement have increased. In addition, our ability to access capital markets could be limited by the recent downgrade or further downgrade of our credit or the credit rating of our general partner, DCP Midstream, LLC.

Rating agencies recently announced downgrades in the credit ratings of DCP Midstream, LLC's outstanding indebtedness. According to these rating agencies, the downgrades were taken in reflection of the significant deterioration in NGL prices, and our and DCP Midstream, LLC's exposure to those prices, given that DCP Midstream, LLC is the counterparty to a significant portion of our derivative instruments.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold our securities, although such credit ratings may affect the market value of our debt instruments. Ratings are subject to revision or withdrawal at any time by the ratings agencies.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

We continue to have the ability to incur additional debt, subject to limitations within our Amended and Restated Credit Agreement. Our level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- an increased amount of cash flow will be required to make interest payments on our debt;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our ability to obtain new debt funding or service our existing debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors. In addition, our ability to service debt under our Amended and Restated Credit Agreement will depend on market interest rates. If our operating results are not sufficient to service our current or future indebtedness, we may take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms, or at all.

Restrictions in our loan agreements may limit our ability to make distributions to unitholders and may limit our ability to capitalize on acquisitions and other business opportunities.

Our loan agreements contain covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates. Furthermore, our loan agreements contain covenants requiring us to maintain a certain leverage ratio and certain other tests. Any subsequent replacement of our loan agreements or any new indebtedness could have similar or greater restrictions. If our covenants are not met, whether as a result of reduced production levels of natural gas and NGLs as described above or otherwise, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

Changes in interest rates may adversely impact our ability to issue additional equity or incur debt, as well as the ability of exploration and production companies to finance new drilling programs around our systems.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related 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 impair our ability to issue additional equity or incur debt to make acquisitions, for other purposes. Increased interest costs could also inhibit the financing of new capital drilling programs by exploration and production companies served by our systems.

Our outstanding notes are senior unsecured obligations of our operating subsidiary, DCP Midstream Operating, LP, or DCP Operating, and are not guaranteed by any of our subsidiaries. As a result, our notes are effectively junior to DCP Operating's existing and future secured debt and to all debt and other liabilities of its subsidiaries.

Our 3.25% Senior Notes due 2015, 2.50% Senior Notes due 2017, 2.70% Senior Notes due 2019, 4.95% Senior Notes due 2022, 3.875% Senior Notes due 2023, and 5.60% Senior Notes due 2044, or our notes, are senior unsecured obligations of our indirect 100% owned subsidiary, DCP Operating, and rank equally in right of payment with all of its other existing and future senior unsecured debt. All of our operating assets are owned by our subsidiaries, and none of these subsidiaries guarantee DCP Operating's obligations with respect to the notes. Creditors of DCP Operating's subsidiaries may have claims with respect to the assets of those subsidiaries that rank effectively senior to the notes. In the event of any distribution or payment of assets of such subsidiaries in any dissolution, winding up, liquidation, reorganization or bankruptcy proceeding, the claims of those creditors would be satisfied prior to making any such distribution or payment to DCP Operating in respect of its direct or indirect equity interests in such subsidiaries. Consequently, after satisfaction of the claims of such creditors, there may be little or no amounts left available to make payments in respect of our notes. As of December 31, 2014, DCP Operating's subsidiaries had no debt for borrowed money owing to any unaffiliated third parties. However, such subsidiaries are not prohibited under the indenture governing the notes from incurring indebtedness in the future.

In addition, because our notes and our guarantees of our notes are unsecured, holders of any secured indebtedness of us would have claims with respect to the assets constituting collateral for such indebtedness that are senior to the claims of the holders of our notes. Currently, we do not have any secured indebtedness. Although the indenture governing our notes places some limitations on our ability to create liens securing debt, there are significant exceptions to these limitations that will allow us to secure significant amounts of indebtedness without equally and ratably securing the notes. If we incur secured indebtedness and such indebtedness is either accelerated or becomes subject to a bankruptcy, liquidation or reorganization, our assets would be used to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on our notes. Consequently, any such secured indebtedness would effectively be senior to our notes and our guarantee of our notes, to the extent of the value of the collateral securing the secured indebtedness. In that event, our noteholders may not be able to recover all the principal or interest due under our notes.

Our significant indebtedness and the restrictions in our debt agreements may adversely affect our future financial and operating flexibility.

As of December 31, 2014, our consolidated indebtedness was $2,325 million, which excludes $14 million in unamortized discount. Our significant indebtedness and the additional debt we may incur in the future for potential acquisitions may adversely affect our liquidity and therefore our ability to make interest payments on our notes.

Debt service obligations and restrictive covenants in our Amended and Restated Credit Agreement, and the indenture and commercial paper dealer agreements governing our notes may adversely affect our ability to finance future operations, pursue acquisitions and fund other capital needs as well as our ability to make cash distributions to our unitholders. In addition, this leverage may make our results of operations more susceptible to adverse economic or operating conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

If we incur any additional indebtedness, including trade payables, that ranks equally with our notes, the holders of that debt will be entitled to share ratably with the holders of our notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding up of us or DCP Operating. This may have the effect of reducing the amount of proceeds paid to our noteholders. If new debt is added to our current debt levels, the related risks that we now face could intensify.

The adoption of financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

We hedge a portion of our commodity risk and our interest rate risk. In its rulemaking under the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Act, the Commodities Futures Trading Commission, or CFTC, adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in Federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. The CFTC filed a notice of appeal with respect to this ruling but on October 29, 2013, voted to voluntarily dismiss the appeal. On November 5, 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC has extended the comment period for these new rules multiple times, with the most recent extension that ended on January 22, 2015. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. Under the rules adopted by the CFTC, we believe our hedging transactions will qualify for the non-financial, commercial end user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, and as a result, we do not expect our hedging activity to be subject to mandatory clearing. The Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Act may also require the counterparties to our derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and related regulations could significantly increase the cost of derivatives contracts for our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging as a result of the legislation and regulations, 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 and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

Future disruptions in the global credit markets may make equity and debt markets less accessible and capital markets more costly, create a shortage in the availability of credit and lead to credit market volatility, which could disrupt our financing plans and limit our ability to grow.

From time to time, public equity markets experience significant declines, and global credit markets experience a shortage in overall liquidity and a resulting disruption in the availability of credit. Future disruptions in the global financial marketplace, including the bankruptcy or restructuring of financial institutions, could make equity and debt markets inaccessible, and adversely affect the availability of credit already arranged and the availability and cost of credit in the future. We have availability under our Amended and Restated Credit Agreement to borrow additional capital, but our ability to borrow under that facility could be impaired if one or more of our lenders fails to honor its contractual obligation to lend to us.

As a publicly traded partnership, these developments could significantly impair our ability to make acquisitions or finance growth projects. We distribute all of our available cash, as defined in our partnership agreement, to our unitholders on a quarterly basis. We rely upon external financing sources, including the issuance of debt and equity securities and bank borrowings, to fund acquisitions or expansion capital expenditures or fund routine periodic working capital needs. Any limitations on our access to external capital, including limitations caused by illiquidity or volatility in the capital markets, may impair our ability to complete future acquisitions and construction projects on favorable terms, if at all. As a result, we may be at a competitive disadvantage as compared to businesses that reinvest all of their available cash to expand ongoing operations, particularly under adverse economic conditions.

Volatility in the capital markets may adversely impact our liquidity.

The capital markets may experience volatility, which may lead to financial uncertainty. Our access to funds under the Amended and Restated Credit Agreement is dependent on the ability of the lenders that are party to the Amended and Restated Credit Agreement to meet their funding obligations. Those lenders may not be able to meet their funding commitments if they experience shortages of capital and liquidity. If lenders under the Amended and Restated Credit Agreement were to fail to fund their share of the Amended and Restated Credit Agreement, our available borrowings could be further reduced. In addition, our borrowing capacity may be further limited by the Amended and Restated Credit Agreement's financial covenant requirements.

A significant downturn in the economy could adversely affect our results of operations, financial position or cash flows. In the event that our results were negatively impacted, we could require additional borrowings. A deterioration of the capital markets could adversely affect our ability to access funds on reasonable terms in a timely manner.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

The partnership is a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than equity in our subsidiaries and equity investees. As a result, our ability to make required payments on our notes depends on the performance of our subsidiaries and their ability to distribute funds to us.

The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit instruments, applicable state business organization laws and other laws and regulations. If our subsidiaries are prevented from distributing funds to us, we may be unable to pay all the principal and interest on the notes when due.

We may incur significant costs and liabilities resulting from implementing and administering pipeline and asset integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, the DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in "high consequence areas." The regulations require operators 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.

Pipeline safety legislation enacted in 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the Pipeline Safety and Job Creations Act, reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. New rules proposed by DOT's PHMSA, address many areas of this legislation. Extending the integrity management requirements to our gathering lines would impose additional obligations on us and could add material cost to our operations.

Although many of our natural gas facilities fall within a class that is not subject to current pipeline integrity requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with non-exempt pipelines. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, or new requirements that may be imposed as a result of the Pipeline Safety and Job Creation Act, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, we may be affected by the testing, maintenance and repair of pipeline facilities downstream from our own facilities. With the exception of our Wattenberg pipeline, our NGL pipelines are also subject to integrity management and other safety regulations imposed by the Texas Railroad Commission, or TRRC.

We currently estimate that we will incur between $4 million and $6 million between 2015 and 2019 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, or new requirements that may be imposed as a result of the Pipeline Safety and Job Creation Act, which costs could be substantial.

We currently transport NGLs produced at our processing plants on our owned and third party NGL pipelines. Accordingly, in the event that an owned or third party NGL pipeline becomes inoperable due to any necessary repairs resulting from integrity testing programs or for any other reason for any significant period of time, we would need to transport NGLs by other means. There can be no assurance that we will be able to enter into alternative transportation arrangements under comparable terms.

Any new or expanded pipeline integrity requirements or the adoption of other asset integrity requirements could also increase our cost of operation and impair our ability to provide service during the period in which assessments and repairs take place, adversely affecting our business. Further, execution of and compliance with such integrity programs may cause us to incur greater than expected capital and operating expenditures for repairs and upgrades that are necessary to ensure the continued safe and reliable operation of our assets.

State and local legislative and regulatory initiatives relating to oil and gas operations could adversely affect our third-party customers' production and, therefore, adversely impact our midstream operations.

Certain states in which we operate have adopted, and other states are considering adopting, measures that could impose new or more stringent requirements on oil and gas exploration and production activities. For example, in exchange for the withdrawal of several initiatives relating to statewide and local government curtailment of oil and gas operations proposed for inclusion on the Colorado state ballot in November 2014, the governor of Colorado created the Task Force on State and Local Regulation of Oil and Gas Operations to make recommendations regarding the responsible development of Colorado's oil and gas resources. It is possible that, as a result of the Task Force's recommendations, the Colorado state legislature could enact new legislation or Colorado state agencies could enact new regulations relating to oil and gas operations, including measures that would give local governments in Colorado greater authority to limit hydraulic fracturing and other oil and gas operations.

In the event state or local restrictions or prohibitions are adopted in our areas of operations, such as in the Wattenberg field, our customers may incur significant compliance costs or may experience delays or curtailment in the pursuit of their exploration, development, or production activities, and possibly be limited or precluded in the drilling of certain wells altogether. Any adverse impact on our customers' activities would have a corresponding negative impact on our throughput volumes. In addition, while conflicts associated with upstream development activities are the primary focus of the Task Force deliberations and the broader policy debate in Colorado generally, certain proposals may, if adopted, directly impact our ability to competitively locate, construct, maintain, and operate our own assets. Accordingly, such restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, cash flows and ability to make distributions to our unitholders.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances or hydrocarbons into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example, (1) the federal Clean Air Act and comparable state laws and regulations, including federal and state air permits, that impose obligations related to air emissions; (2) the federal RCRA and comparable state laws that impose requirements for the management, storage and disposal of hazardous and solid waste from our facilities; (3) the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, or CERCLA, also known as "Superfund," and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal; and (4) the Clean Water Act and the Oil Pollution Act, and comparable state laws that impose requirements on discharges to waters as well as requirements to prevent and respond to releases of hydrocarbons to Waters of the United States. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental regulations, including CERCLA and analogous state laws and regulations, impose strict liability or joint and several liability for costs required to clean up and restore sites where hazardous substances, and in some cases hydrocarbons, have been disposed or otherwise released.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas, NGLs and other petroleum products, air emissions related to our operations, and historical industry operations and waste management and disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, governmental claims for natural resource damages, or fines or penalties for related violations of environmental laws, permits or regulations. In addition, it is possible that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance or from indemnification from DCP Midstream, LLC.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets.

The majority of our natural gas gathering and intrastate transportation operations are exempt from FERC regulation under the NGA but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of regular litigation, so the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based on any reassessment by us of the jurisdictional status of our facilities or on future determinations by FERC and the courts.

In addition, the rates, terms and conditions of some of the transportation services we provide on our Cipco pipeline system, EasTrans Pipeline system, and Pelico pipeline system are subject to FERC regulation under Section 311 of the NGPA. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The Cipco and Pelico systems are currently charging rates for their Section 311 transportation services that were deemed fair and equitable under a rate settlement approved by FERC. The EasTrans system is currently charging rates for its Section 311 transportation services that were deemed fair and equitable under an order approved by the Railroad Commission of Texas. The Black Lake, Wattenberg, and Front Range pipelines are interstate transporters of NGLs and are subject to FERC jurisdiction under the Interstate Commerce Act and the Elkins Act.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPACT 2005, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1 million per day for each violation and possible criminal penalties of up to $1 million per violation and five years in prison.

Other state and local regulations also affect our business. Our non-proprietary gathering lines are subject to ratable take and common purchaser statutes in Louisiana. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural gas gathering access and rate discrimination. Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells. While our proprietary gathering lines are currently subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the proprietary status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

Discovery's interstate tariff rates are subject to review and possible adjustment by federal regulators. Moreover, because Discovery is a non-corporate entity, it may be disadvantaged in calculating its cost-of-service for rate-making purposes.

FERC, pursuant to the NGA, regulates many aspects of Discovery's interstate pipeline transportation service, including the rates that Discovery is permitted to charge for such service. Under the NGA, interstate transportation rates must be just and reasonable and not unduly discriminatory. If FERC fails to permit tariff rate increases requested by Discovery, or if FERC lowers the tariff rates Discovery is permitted to charge its customers, on its own initiative, or as a result of challenges raised by Discovery's customers or third parties, Discovery's tariff rates may be insufficient to recover the full cost of providing interstate transportation service. In certain circumstances, FERC also has the power to order refunds.

Under current policy, FERC permits pipelines to include, in the cost-of-service used as the basis for calculating the pipeline's regulated rates, a tax allowance reflecting the actual or potential income tax liability on public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. In a future rate case, Discovery may be required to demonstrate the extent to which inclusion of an income tax allowance in Discovery's cost-of-service is permitted under the current income tax allowance policy.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPACT 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and possible criminal penalties of up to $1 million per violation and five years in prison.

Spills and their aftermath could lead to additional governmental regulation of the offshore exploration and production industry, which may result in substantial cost increases or delays in our offshore natural gas gathering activities.

In April 2010, a deepwater exploration well located in the Gulf of Mexico, owned and operated by companies unrelated to us, sustained a blowout and subsequent explosion leading to the leaking of hydrocarbons. In response to this event, certain federal agencies and governmental officials ordered additional inspections of deepwater operations in the Gulf of Mexico. On May 28, 2010, a six-month federal moratorium was implemented on all offshore deepwater drilling projects. On October 12, 2010, the Department of the Interior announced it was lifting the deepwater drilling moratorium. Despite the fact that the drilling moratorium was lifted, this spill and its aftermath has led to additional governmental regulation of the offshore exploration and production industry and delays in the issuance of drilling permits, which may result in volume impacts, cost increases or delays in our offshore natural gas gathering activities, which could materially impact Discovery's operations, including Keathley Canyon, and our business, financial condition and results of operations.

Recently proposed or finalized rules imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

On August 16, 2012, the EPA issued final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards, or NSPS, to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from existing natural gas wells that are re-fractured, as well as newly-drilled and fractured wells through the use of reduced emission completions or "green completions" and well completion combustion devices, such as flaring, as of January 1, 2015. In addition, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with emissions reduction requirements for dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules further establish new requirements for detection and repair of leaks exceeding 500 parts per million in concentration at natural gas processing plants. In January 2013, the EPA stated that it intends to reconsider portions of the rule. On September 23, 2013, the EPA issued limited revisions to the rule regarding standards for storage tanks subject to the NSPS and on December 19, 2014, revised definitions related to the stages of well completion and amended storage tank requirements. The EPA has stated that it continues to review other issues raised in Petitions for Reconsideration; the rule is also the subject of Petitions for Review before the U.S. Circuit Court of Appeals for the District of Columbia. In addition, in January 2015, the EPA announced its intention to expand existing NSPS regulations for new or modified sources of VOCs and methane emissions, and institute Control Technology Guidelines for VOC emissions reductions related to ozone, as part of the EPA's strategy to reduce methane and ozone-forming VOC emissions from the oil and gas sector. These regulations and guidelines are intended to be instituted by the EPA over the course of 2015 to 2019. Relatedly, in November 2014, the EPA proposed to revise and lower the ambient air quality standard for ozone in the U.S. under the Clean Air Act, from 75 parts per billion to between 65 and 70 parts per billion, which is likely to result in more, and expanded, ozone non-attainment areas, which in turn will require states to adopt implementation plans to reduce emissions of ozone-forming pollutants, like VOCs and nitrogen oxides, that are emitted from, among others, the oil and gas sector. These regulations could require modifications to the operations of our natural gas exploration and production customers as well as our operations including the installation of new equipment and new emissions management practices, which could result in significant additional costs, both increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our customers could result in reduced production by those customers and thus translate into reduced demand for our services, which could in turn have an adverse effect on our business and cash available for distributions.

We may incur significant costs in the future associated with proposed climate change regulation and legislation.

The United States Congress and some states where we have operations may consider legislation related to greenhouse gas emissions, including compelling reductions of such emissions. In addition, there have recently been international conventions and efforts to establish standards for the reduction of greenhouse gases globally. Some of these proposals may include limitations, or caps, on the amount of greenhouse gas that can be emitted, as well as a system of emissions allowances. Legislation passed by the US House of Representatives in 2010, which was not taken up by the Senate, would have placed the entire burden of obtaining allowances for the carbon content of NGLs on the owners of NGLs at the point of fractionation. In June 2013, the President announced a climate action plan that targets methane emissions from the oil and gas sector as part of a comprehensive interagency methane reduction strategy, and in January 2015, the EPA announced that it would issue proposed new source performance standards for methane (a greenhouse gas) from new and modified oil and gas sector sources in 2015 and finalize those standards in 2016. The EPA also indicated that it would issue Control Technology Guidelines for emissions of VOCs from oil and gas sector sources in nonattainment areas, with an expected co-benefit of reduced methane emissions, and in November 2014, proposed to reduce the ambient ozone standard from 75 parts per billion to between 65 and 70 parts per billion under the Clean Air Act by October 2015. The EPA in 2011 issued permitting rules for sources of greenhouse gases; however, in June 2014 the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals decision upholding these rules and struck down the EPA's greenhouse gas permitting rules to the extent they impose a requirement to obtain a permit based solely on emissions of greenhouse gases. Large sources of other air pollutants, such as VOCs or nitrogen oxides, could still be required to implement process or technology controls and obtain permits regarding emissions of greenhouse gases. Further, the

EPA also has issued rules requiring reporting of greenhouse gas, on an annual basis, for certain onshore natural gas and oil production facilities and in December 2014, proposed to amend and expand greenhouse gas reporting requirements to all segments of the oil and gas sector, with a final regulation expected to be effective by January 2016. To the extent legislation is enacted or additional regulations are promulgated that regulate greenhouse gas emissions, it could significantly increase our costs to (i) acquire allowances; (ii) permit new large facilities; (iii) operate and maintain our facilities; (iv) install new emission controls or institute emission reduction; and (v) manage a greenhouse gas emissions program. If such legislation becomes law or additional rules are promulgated in the United States or any states in which we have operations and we are unable to pass these costs through as part of our services, it could have an adverse effect on our business and cash available for distributions.

Increased regulation of hydraulic fracturing could result in reductions, delays or increased costs in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas that we gather, process and transport.

Certain of our customers' natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand, and chemicals are injected under pressure into subsurface formations to stimulate hydrocarbon production. While the underground injection of fluids is regulated by the U.S. EPA under the Safe Drinking Water Act, or SDWA, fracturing is excluded from regulation unless the injection fluid is diesel fuel. The EPA has published an interpretive memorandum and permitting guidance related to regulation of fracturing fluids using this regulatory authority. The EPA is also considering various regulatory programs directed at hydraulic fracturing. For example, the EPA may propose regulations in 2015 under the federal Clean Water Act to further regulate wastewater discharges from hydraulic fracturing and other natural gas production. The EPA is also intending to expand existing Clean Air Act new source performance standards for new and modified air emissions sources, and institute Control Technology Guidelines for existing sources in ozone non-attainment areas, to reduce emissions of methane or VOCs from oil and gas sources, including drilling and production processes. The adoption of new federal laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult for our customers to complete oil and natural gas wells in shale formations and increase their costs of compliance. In addition, the U.S. EPA is currently studying the potential adverse impact that each stage of hydraulic fracturing may have on the environment. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely.

In addition, federal agencies have recently initiated certain other regulatory initiatives or reviews of certain aspects of hydraulic fracturing that could further increase our natural gas exploration and production customer's costs and decrease their levels of production. On May 11, 2012, the federal Bureau of Land Management, or BLM, announced draft rules that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon Native American Indian and other federal lands; a revised rule was released for public comment on May 25, 2013, and is under review by the Office of Management and Budget. The adoption and implementation of rules relating to hydraulic fracturing could result in increased expenditures for our natural gas exploration and production customers, which could cause them to reduce their production and thereby result in reduced demand for our services by these customers.

Construction of new assets is subject to regulatory, environmental, political, legal, economic and other risks that may adversely affect our financial results.

The construction of new midstream facilities or additions or modifications to our existing midstream asset systems or propane terminals involves numerous regulatory, environmental, political and legal and economic uncertainties beyond our control and may require the expenditure of significant amounts of capital. Construction expenditures may occur over an extended period of time, yet we will not receive any material increases in cash flow until the project is completed and fully operational. Moreover, our cash flow from a project may be delayed or may not meet our expectations. These projects may not be completed on schedule or within budgeted cost, or at all. We may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we often do not have access to third party estimates of potential reserves in an area prior to constructing facilities in such area. To the extent we rely on estimates of future production in our decision to construct new systems or additions to our systems, such estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, these facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. The construction of new systems or additions to our existing gathering, transportation and propane terminal assets may require us to obtain new rights-of-way prior to constructing these facilities. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines, expand our network of propane terminals, or capitalize on other attractive expansion opportunities. The construction of new systems or additions to our existing gathering, transportation and propane terminal assets may require us to rely on third parties downstream of our facilities to have available capacity for our delivered natural gas, NGLs, or propane. If such third party facilities are not constructed or operational at the time that the addition to our facilities is completed, we may experience adverse effects on our results of operations and financial condition. The construction of additional systems may require greater capital investment if the commodity prices of certain supplies such as steel increase. Construction also subjects us to risks related to the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control that could adversely affect results of operations, financial position or cash flows.

If we do not make acquisitions on economically acceptable terms, our future growth could be limited.

Our ability to make acquisitions that are accretive to our cash generated from operations per unit is based upon our ability to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them and obtain financing for these acquisitions on economically acceptable terms. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations per unit. Additionally, net assets contributed by DCP Midstream, LLC represent a transfer of net assets between entities under common control, and are recognized at DCP Midstream, LLC's basis in the net assets transferred. The amount of the purchase price in excess of DCP Midstream, LLC's basis in the net assets, if any, is recognized as a reduction to partners' equity. Conversely, the amount of the purchase price less than DCP Midstream's basis in the net assets, if any, is recognized as an increase to partners' equity.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, future contract terms with customers, revenues and costs, including synergies;
- an inability to successfully integrate the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- change in competitive landscape;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

In addition, any limitations on our access to substantial new capital to finance strategic acquisitions will impair our ability to execute this component of our growth strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of capital include market conditions and offering or borrowing costs such as interest rates or underwriting discounts.

We may not be able to grow or effectively manage our growth.

A principal focus of our strategy is to continue to grow the per unit distribution on our units by expanding our business. Our future growth will depend upon a number of factors, some of which we can control and some of which we cannot. These factors include our ability to:

- complete construction projects and consummate accretive acquisitions or joint ventures;
- identify businesses engaged in managing, operating or owning pipelines, processing and storage assets or other midstream assets for acquisitions, joint ventures and construction projects;
- participate in dropdown opportunities with DCP Midstream, LLC;
- appropriately identify liabilities associated with acquired businesses or assets;
- integrate acquired or constructed businesses or assets successfully with our existing operations and into our operating and financial systems and controls;
- hire, train and retain qualified personnel to manage and operate our growing business; and
- obtain required financing for our existing and new operations at reasonable rates.

A deficiency in any of these factors could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from acquisitions, joint ventures or construction projects. In addition, competition from other buyers could reduce our acquisition opportunities. DCP Midstream, LLC and its affiliates are not restricted from competing with us. DCP Midstream, LLC and its affiliates may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Furthermore, we have recently grown through a number of organic projects, dropdowns and acquisitions. If we fail to properly integrate these assets successfully with our existing operations, if the future performance of these assets does not meet our expectations, if we did not properly value the assets, or we did not identify significant liabilities associated with acquired assets, the anticipated benefits from these transactions may not be fully realized.

Dropdowns and acquisitions may not be beneficial to us.

Dropdowns and acquisitions involve numerous risks, including:

- the failure to realize expected profitability, growth or accretion;
- an increase in indebtedness and borrowing costs;
- potential environmental or regulatory compliance matters or liabilities;
- potential title issues;
- the incurrence of unanticipated liabilities and costs; and
- the temporary diversion of management's attention from managing the remainder of our assets to the process of integrating the acquired businesses.

Assets recently acquired will also be subject to many of the same risks as our existing assets. If any of these risks or unanticipated liabilities or costs were to materialize, any desired benefits of these acquisitions may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

If we are not able to purchase propane from our principal suppliers, or we are unable to secure transportation under our transportation arrangements, our results of operations in our wholesale propane logistics business would be adversely affected.

Most of our propane purchases are made under supply contracts that are annual or multi-year agreements and provide various index-based pricing formulas. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our four primary suppliers of propane, one of which is an affiliated entity, represented approximately 80% of our propane supplied during the year ended December 31, 2014. In the event that we are unable to purchase propane from our significant suppliers due to their failure to perform under contractual obligations or otherwise, replace terminated or expired supply contracts, or if there are domestic or international supply disruptions, our failure to obtain alternate sources of supply at competitive prices and on a timely basis would affect our ability to satisfy customer demand, reduce our revenues and adversely affect our results of operations. In addition, if we are unable to transport propane supply to our terminals, our ability to satisfy customer demand, our revenue and results of operations would be adversely affected.

Service at our propane terminals may be interrupted.

Historically, a substantial portion of the propane we purchase to support our wholesale propane logistics business is delivered at our rail terminals or by ship at our leased marine terminal in Providence, Rhode Island and at our owned marine terminal in Chesapeake, Virginia. We also rely on shipments of propane via TEPPCO Partners, LP's pipeline to open access terminals. Any significant interruption in the service at these terminals would adversely affect our ability to obtain propane, which could reduce the amount of propane that we distribute and impact our revenues or cash available for distribution.

Our operating results for our Wholesale Propane Logistics Segment fluctuate on a seasonal and quarterly basis.

Revenues from our Wholesale Propane Logistics Segment have seasonal characteristics. In many parts of the country, demand for propane and other fuels peaks during the winter months. As a result, our overall operating results fluctuate on a seasonal basis. Demand for propane and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and pipeline systems and the terms of our transportation arrangements relative to demand created by unusual weather patterns.

Our assets and operations can be affected by weather, weather-related conditions and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, tornadoes, wind, lightning, cold weather and other natural phenomena, which could impact our results of operations and make it more difficult for us to realize historic rates of return. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss and in some instances, we have been unable to obtain insurance on some of our assets on commercially reasonable terms, if at all. If we incur a significant disruption in our operations or a significant liability for which we were not fully insured, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to continue to make cash distributions to holders of our common units at our current distribution rate.

The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, level of production of, and demand for natural gas, condensate, NGLs and propane;
- the success of our commodity and interest rate hedging programs in mitigating fluctuations in commodity prices and interest rates;
- the volume and quality of natural gas we gather, compress, treat, process, transport and sell, and the volume of NGLs we process, transport, sell and store, and the volume of propane we transport, sell and store;
- the operational performance and efficiency of our assets, including our plants and equipment;
- the operational performance and efficiency of third-party processing, fractionation or other facilities that provide services to us;
- the relationship between natural gas, NGL and crude oil prices;
- the level of competition from other energy companies;
- the impact of weather conditions on the demand for natural gas, NGLs and propane;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;
- the cost and form of payment for acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets at reasonable rates;
- restrictions contained in our debt agreements;
- the timing of our producers' obligations to make volume deficiency payments to us;
- the amount of cash distributions we receive from our equity interests;
- the amount of cost reimbursements to our general partner;
- the amount of cash reserves established by our general partner; and
- new, additions to and changes in laws and regulations.

We have partial ownership interests in certain joint venture legal entities, including Southern Hills, Sand Hills, Discovery, the Mont Belvieu fractionators, Texas Express, CrossPoint, Front Range and Panola which could adversely affect our ability to operate and control these entities. In addition, we may be unable to control the amount of cash we will receive from the operation of these entities and we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.

Our inability, or limited ability, to control the operations and management of joint venture legal entities that we have a partial ownership interest in may mean that we will not receive the amount of cash we expect to be distributed to us. In addition, for entities in which we have a minority ownership interest, we will be unable to control ongoing operational decisions, including the incurrence of capital expenditures that we may be required to fund. Specifically,

- we have limited ability to control decisions with respect to the operations of these entities and their subsidiaries, including decisions with respect to incurrence of expenses and distributions to us;
- these entities may establish reserves for working capital, capital projects, environmental matters and legal proceedings which would otherwise reduce cash available for distribution to us;

- these entities may incur additional indebtedness, and principal and interest made on such indebtedness may reduce cash otherwise available for distribution to us; and
- these entities may require us to make additional capital contributions to fund working capital and capital expenditures, our funding of which could reduce the amount of cash otherwise available for distribution.

All of these items could significantly and adversely impact our ability to distribute cash to our unitholders.

The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flow and not solely on profitability.

Profitability may be significantly affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Competition from alternative energy sources, conservation efforts and energy efficiency and technological advances may reduce the demand for propane.

Competition from alternative energy sources, including natural gas and electricity, has been increasing as a result of reduced regulation of many utilities. In addition, propane competes with heating oil primarily in residential applications. Propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because natural gas is a less expensive source of energy than propane. The gradual expansion of natural gas distribution systems and availability of natural gas in the northeast, which has historically depended upon propane, could reduce the demand for propane, which could adversely affect the volumes of propane that we distribute. In addition, stricter conservation measures in the future or technological advances in heating, energy generation or other devices could reduce the demand for propane.

We do not own all of the land on which our pipelines, facilities and rail terminals are located, which may subject us to increased costs.

Upon contract lease renewal, we may be subject to more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights of way or if such rights of way lapse or terminate. Certain of our leases contain renewal provisions that allow for our continued use and access of the subject land and, although we review and renew our leases as a routine business matter, there may be instances where we may not be able to renew our contract leases on commercially reasonable terms or may have to commence eminent domain proceedings to establish our right to continue to use the land. We obtain the rights to construct and operate our pipelines, surface sites and rail terminals on land owned by third parties and governmental agencies for a specific period of time.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.

Our operations, and the operations of third parties, are subject to many hazards inherent in the gathering, compressing, treating, processing, storing, transporting and fractionating, as applicable, of natural gas, propane and NGLs, including:

- damage to pipelines, plants, terminals, storage facilities and related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, farm and utility equipment;
- leaks of natural gas, propane, NGLs and other hydrocarbons from our pipelines, plants, terminals, or storage facilities, or losses of natural gas, propane or NGLs as a result of the malfunction of equipment or facilities;
- contaminants in the pipeline system;
- fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks inherent to our business, including offshore wind. Although we insure most of our underground pipeline systems against property damage, certain of our gathering pipelines are not covered. We are not insured against all environmental accidents that might occur, which may include toxic tort claims, other than those considered to be sudden and accidental. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage, or may become prohibitively expensive, and we may elect not to carry such a policy.

Our business could be negatively impacted by security threats, including cybersecurity threats, terrorist attacks, the threat of terrorist attacks, sustained military campaigns and related disruptions.

We face cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable. Cybersecurity threats are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

We face the threat of future terrorist attacks on both our industry in general and on us, including the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. The increased security measures we have taken as a precaution against possible terrorist attacks have resulted in increased costs to our business. Any physical damage to facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our business and cash flows. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Due to our lack of industry diversification, adverse developments in our midstream operations or operating areas would reduce our ability to make distributions to our unitholders.

We rely on the cash flow generated from our midstream energy businesses, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas, propane, condensate and NGLs. Due to our lack of diversification in industry type, an adverse development in one of these businesses, like the current commodity price environment, may have a significant impact on our company.

We are exposed to the credit risks of our key producer customers and propane purchasers, and any material nonpayment or nonperformance by our key producer customers or our propane purchasers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our producer customers and propane purchasers. Any material nonpayment or nonperformance by our key producer customers or our propane purchasers could reduce our ability to make distributions to our unitholders. Furthermore, some of our producer customers or our propane purchasers may be highly leveraged and subject to their own operating and regulatory risks, which could increase the risk that they may default on their obligations to us. Additionally, a decline in the availability of credit to producers in and surrounding our geographic footprint could decrease the level of capital investment and growth that would otherwise bring new volumes to our existing assets and facilities.

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

The natural gas we gather, compress, treat, process, transport, sell and store is delivered into pipelines for further delivery to end-users. If these pipelines are capacity constrained and cannot, or will not, accept delivery of the gas due to downstream constraints on the pipeline or changes in interstate pipeline gas quality specifications, we may be forced to limit or stop the flow of gas through our pipelines and processing and treating facilities. In addition, interruption of pipeline service upstream of our processing facilities would limit or stop flow through our processing and fractionation facilities. Likewise, if the pipelines into which we deliver NGLs are interrupted, we may be limited in, or prevented from conducting, our NGL transportation operations. Any number of factors beyond our control could cause such interruptions or constraints on pipeline service, including necessary and scheduled maintenance, or unexpected damage to the pipelines. Because our revenues and net operating margins depend upon (i) the volumes of natural gas we process, gather and transmit, (ii) the throughput of NGLs through our transportation, fractionation and storage facilities and (iii) the volume of natural gas we gather and transport, any reduction of volumes could adversely affect our operations and cash flows available for distribution to our unitholders.

Risks Inherent in an Investment in Our Common Units

Conflicts of interest may exist between our individual unitholders and DCP Midstream, LLC, our general partner, which has sole responsibility for conducting our business and managing our operations.

DCP Midstream, LLC owns and controls our general partner. Some of our general partner's directors, and some of its executive officers, are directors or officers of DCP Midstream, LLC or its owners. Therefore, conflicts of interest may arise between DCP Midstream, LLC and its affiliates and our unitholders. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires DCP Midstream, LLC to pursue a business strategy that favors us. DCP Midstream, LLC's directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of DCP Midstream, LLC, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as DCP Midstream, LLC and its affiliates, in resolving conflicts of interest;
- DCP Midstream, LLC and its affiliates, including Phillips 66 and Spectra Energy, are not limited in their ability to compete with us. Please read "DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us" below;
- once certain requirements are met, our general partner may make a determination to receive a quantity of our Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights without the approval of the special committee of our general partner or our unitholders;
- some officers of DCP Midstream, LLC and DCP Midstream GP, LLC who provide services to us also will devote significant time to the business of DCP Midstream, LLC, and will be compensated by DCP Midstream, LLC for the services rendered to it;
- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.

Neither our partnership agreement nor the Services Agreement, as amended, between us, DCP Midstream, LLC and others will prohibit DCP Midstream, LLC and its affiliates, including Phillips 66 and Spectra Energy, from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, DCP Midstream, LLC and its affiliates, including Phillips 66 and Spectra Energy, may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Each of these entities is a large, established participant in the midstream energy business, and each has significantly greater resources and experience than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and cash available for distribution.

Cost reimbursements due to our general partner and its affiliates for services provided, which will be determined by our general partner, will be material.

Pursuant to the Services Agreement, as amended, we entered into with DCP Midstream, LLC, our general partner and others, DCP Midstream, LLC will receive reimbursement for the payment of operating expenses related to our operations and for the provision of various general and administrative services for our benefit. Payments for these services will be material. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. These factors may reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common units.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, DCP Midstream, LLC. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement permits our general partner to make a number of decisions either in its individual capacity, as opposed to in its capacity as our general partner or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include:

- the exercise of its right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, a number of Class B units that are convertible at any time following the first anniversary of the issuance of these Class B units into common units;
- its limited call right;
- its voting rights with respect to the units it owns;
- its registration rights; and
- its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder will agree to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

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

- 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, meaning it believed the decision was in the best interests of our partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the special committee of the board of directors of our general partner and not involving a vote of our unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be "fair and reasonable" to us, as determined by our general partner in good faith and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons 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.

Our general partner may elect to cause us to issue Class B 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 special committee of our general partner or holders of our common units. This may result in lower distributions to holders of our common units in certain situations.

Our general partner currently has the right to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election, or 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 amount. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, in certain situations, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

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. Our unitholders do not elect our general partner or its board of directors, and have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner are chosen by the members of our general partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our common units may experience price volatility.

Our common unit price has experienced volatility in the past, and volatility in the price of our common units may occur in the future as a result of any of the risk factors contained herein and the risks described in our other public filings with the SEC. For instance, our common units may experience price volatility as a result of changes in investor sentiment with respect to our competitors, our business partners and our industry in general, which may be influenced by volatility in prices for NGLs, natural gas and crude oil. In addition, the securities markets have from time to time experienced significant price and volume fluctuations that are unrelated to the operating performance of particular companies but affect the market price of their securities. These market fluctuations may also materially and adversely affect the market price of our common units.

Even if holders of our common units are dissatisfied, they may be unable to remove our general partner without its consent.

The unitholders may be unable to remove our general partner without its consent because our general partner and its affiliates own a significant percentage of our outstanding units. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the general partner. As of December 31, 2014, our general partner and its affiliates owned approximately 21.2% of our aggregate outstanding common units.

Our partnership agreement restricts the voting rights of our unitholders owning 20% or more of our common units.

Our unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% 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 our unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of management.

If we are deemed an "investment company" under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our assets include a 50% interest in CrossPoint Pipeline, LLC, a 40% interest in the Discovery system, a 33.33% interest in Front Range, a 33.33% interest in Southern Hills, a 33.33% interest in Sand Hills, a 28.5% interest in Web Duvall, a 20% interest in the Mont Belvieu 1 fractionator, a 15% interest in Panola, a 12.5% interest in the Mont Belvieu Enterprise fractionator and a 10% interest in Texas Express, which may be deemed to be "investment securities" within the meaning of the Investment Company Act of 1940. In the future, we may acquire additional minority owned interests in joint ventures that could be deemed "investment securities." If a sufficient amount of our assets are deemed to be "investment securities" within the meaning of the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events may have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes, and be subject to federal income tax at the corporate tax rate, significantly reducing the cash available for distributions. Additionally, distributions to our unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to our unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forego potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in any of our assets that are deemed to be "investment securities."

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

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from pledging, imposing a lien or transferring all or a portion of their respective ownership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

We may issue additional units without our unitholders' approval, which would dilute our unitholders' existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- 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 the common units may decline.

Our general partner including its affiliates may sell units in the public or private markets, which could reduce the market price of our outstanding common units.

If our general partner or its affiliates holding unregistered units were to dispose of a substantial portion of these units in the public market, whether in a single transaction or series of transactions, it could reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

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

If at any time our general partner and its affiliates own more than 80% of the 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, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Our unitholders may also incur a tax liability upon a sale of their units.

The liability of holders of limited partner interests 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 without 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 of the other states in which we do business. Holders of limited partner interests could be liable for any and all of our obligations as if such holder were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state’s partnership statute; or
- the right of holders of limited partner interests 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 liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our 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. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the 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.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our being subject to minimal entity-level taxation by individual states. If the Internal Revenue Service, or 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 regarding our status as a partnership.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we will be treated as a corporation, the IRS could disagree with the positions we take or 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 or otherwise subject us to taxation as an entity.

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%, and would likely pay state income tax at varying rates. Distributions to a unitholder would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to the unitholder. Because a tax would be imposed upon us as a corporation, our cash available for distribution to a unitholder would be substantially reduced. Therefore, treatment of us as a corporation for federal tax purposes would result in a material reduction in the anticipated cash flow and after-tax return to a unitholder, likely causing a substantial reduction in the value of our common units.

The partnership agreement provides that if a law is enacted or 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 levels will be adjusted to reflect the impact of that law on us.

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

The present 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. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception that allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our common units. For example, members of the U.S. Congress considered, and the President's Administration has proposed, substantive changes to the existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. As a specific example, the Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such change could negatively impact the value of an investment in our common units.

Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay the State of Texas a margin tax that is assessed at 0.95% of taxable margin apportioned to Texas. Imposition of such a tax on us by other states would reduce the cash available for distribution to a unitholder. The partnership agreement provides that if a law is enacted or 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 levels will be adjusted to reflect the impact of that law on us.

Changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, with respect to federal, state and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future.

If tax authorities contest the tax positions we take, the market for our common units may be adversely impacted, and the cost of any contest with a tax authority would reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. Tax authorities may adopt positions that differ from the conclusions of our counsel or from the positions we take, and the tax authority's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with a tax authority, and the outcome of any such contest, may increase a unitholder's tax liability and result in adjustment to items unrelated to us and could 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 any tax authority will be borne indirectly by our unitholders and our general partner because such costs will reduce our cash available for distribution.

Our unitholders may be required to pay taxes on income from us even if the unitholders do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income, which could be different in amount than the cash we distribute, 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 cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from that income.

Certain actions that we may take, such as issuing additional units, may increase the federal income tax liability of unitholders.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder's share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder's units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder's tax basis in its units.

In addition, the federal income tax liability of a unitholder could be increased if we dispose of assets or make a future offering of units and use the proceeds in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to our assets.

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

If a unitholder sells its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those common units. Because distributions to a unitholder in excess of the total net taxable income allocated to it for a common unit decreases its tax basis in that common unit, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than their tax basis in that common unit, even if the price is less than their 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 nonrecourse liabilities, if a unitholder sells its units, the unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

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

Investment in common units by tax-exempt entities, such as individual retirement accounts, or IRAs, other retirement plans 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, which may 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 United States federal tax returns and pay tax on their share of our taxable income. If a unitholder is a tax-exempt entity or a non-U.S. person, the unitholder should consult its tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, 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 the 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.

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 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 use of this proration method may not be permitted under existing Treasury Regulations. Although the U.S. Treasury Department 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 among transferor and transferee unitholders, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. Accordingly, our counsel is unable to opine as to the validity of this method. 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.

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

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and such unitholder may be required to 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 units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those 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 and lending their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the 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 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, 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, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the 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.

The sale or exchange of 50% 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 terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination, among other things, would 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 Schedule K-1s if relief from the IRS was not granted, as described below) for one calendar year. Our termination could also 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 result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Under current law, such a termination would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must 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 for publicly traded partnerships that terminate in this manner, whereby if a publicly traded partnership that has terminated requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year, notwithstanding two partnership tax years resulting from the termination.

Unitholders may be subject to state and local taxes and return filing requirements in states where they do not reside as a result of investing in our units.

In addition to federal income taxes, unitholders may be subject to other taxes, including foreign, 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, even if the unitholders do not live in any of those jurisdictions. Unitholders may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, the unitholder may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax or an entity level tax. It is each unitholder's responsibility to file all United States federal, foreign, state and local tax returns. Our outside tax counsel has not rendered an opinion on the state, local or non-U.S. tax consequences of an investment in our common units.

Some of the states in which we do business or own property may require us to, or we may elect to, withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding the amount of which may be greater or less than a particular unitholder's income tax liability to the state generally does not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

For details on our plants, fractionation and storage facilities, propane terminals and pipeline systems, please read "Business - Natural Gas Services Segment," "Business - NGL Logistics Segment" and "Business - Wholesale Propane Logistics Segment." We believe that our properties are generally in good condition, well maintained and are suitable and adequate to carry on our business at capacity for the foreseeable future.

Our real property falls into two categories: (1) parcels that we own in fee; and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to ground leases between us, as lessee, and the fee owner of the lands, as lessors. We, or our predecessors, have leased these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Our principal executive offices are located at 370 17th Street, Suite 2500, Denver, Colorado 80202, our telephone number is 303-633-2900 and our website address is www.dcppartners.com.

Item 3. ***Legal Proceedings***

We are not a party to any significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows. For more information, please read "Environmental Matters."

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

Market Information

Our common units have been listed on the New York Stock Exchange, or the NYSE, under the symbol "DPM" since December 2, 2005. The following table sets forth intra-day high and low sales prices of the common units, as reported by the NYSE, as well as the amount of cash distributions declared per quarter for 2014 and 2013.

Quarter Ended	High	Low	Distribution Per Common Unit
December 31, 2014	56.28	40.09	0.7800
September 30, 2014	57.96	51.27	0.7700
June 30, 2014	57.98	50.17	0.7575
March 31, 2014	51.14	46.88	0.7450
December 31, 2013	50.50	45.02	0.7325
September 30, 2013	58.50	46.14	0.7200
June 30, 2013	54.38	45.01	0.7100
March 31, 2013	46.93	40.44	0.7000

As of February 19, 2015, there were approximately 43 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities.

Distributions of Available Cash

General - Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date, as determined by our general partner.

Definition of Available Cash - Available Cash, for any quarter, consists of 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;
    - 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;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

Minimum Quarterly Distribution - The Minimum Quarterly Distribution, as set forth in the partnership agreement, is $0.35 per unit per quarter, or $1.40 per unit per year. Our current quarterly distribution is $0.78 per unit, or $3.12 per unit annualized. There is no guarantee that we will maintain our current distribution or pay the Minimum Quarterly Distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, 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. Please read "Management's Discussion and Analysis of Financial Condition and Results of

Operations - Capital Requirements - Description of Amended and Restated Credit Agreement" for a discussion of the restrictions included in our Amended and Restated Credit Agreement that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights - As of December 31, 2014, the general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 0.3% and limited partner interest of 1.7%. The 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 interest may 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 current general partner interest.

The incentive distribution rights held by our general partner entitle it to receive an increasing share of Available Cash as pre-defined distribution targets have been achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. Our general partner's incentive distribution rights were not reduced as a result of our recent common unit offerings, and will not be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest. Please read the *Distributions of Available Cash* section in Note 13 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

On January 29, 2015, we announced that the board of directors of DCP Midstream GP, LLC declared a quarterly distribution of $0.78 per unit, which was paid on February 13, 2015, to unitholders of record on February 9, 2015.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" contained herein.

Item 6. *Selected Financial Data*

The following table shows our selected financial data for the periods and as of the dates indicated, which is derived from the consolidated financial statements. The information contained herein should be read together with, and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this Form 10-K.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein to not be indicative of our future financial condition or results of operations. A discussion on our critical accounting estimates is included in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations".

The table should also be read together with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
	2014 (a)	2013 (a)	2012 (a)	2011 (a)	2010 (a)
	(Millions, except per unit amounts)				
Statements of Operations Data:					
Sales of natural gas, propane, NGLs and condensate	$ 3,143	$ 2,763	$ 2,520	$ 3,574	$ 3,118
Transportation, processing and other	345	271	234	208	163
Gains from commodity derivative activity, net (b) (c)	154	17	70	8	3
Total operating revenues	3,642	3,051	2,824	3,790	3,284
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	2,795	2,426	2,215	3,155	2,811
Operating and maintenance expense	216	215	197	192	158
Depreciation and amortization expense	110	95	91	135	117
General and administrative expense	64	63	75	76	67
Step acquisition - equity interest re-measurement gain	—	—	—	—	(9)
Other expense (income)	3	8	—	(1)	(2)
Other income - affiliates	—	—	—	—	(3)
Total operating costs and expenses	3,188	2,807	2,578	3,557	3,139
Operating income	454	244	246	233	145
Interest expense	(86)	(52)	(42)	(34)	(29)
Earnings from unconsolidated affiliates (d)	75	33	26	23	23
Income before income taxes	443	225	230	222	139
Income tax expense	(6)	(8)	(1)	(1)	(2)
Net income	437	217	229	221	137
Net income attributable to noncontrolling interests	(14)	(17)	(13)	(30)	(12)
Net income attributable to partners	$ 423	$ 200	$ 216	$ 191	$ 125
Less:					
Net income attributable to predecessor operations (e)	(6)	(25)	(51)	(91)	(77)
General partner interest in net income	(114)	(70)	(41)	(25)	(17)
Net income allocable to limited partners	$ 303	$ 105	$ 124	$ 75	$ 31
Net income per limited partner unit-basic	$ 2.84	$ 1.34	$ 2.28	$ 1.73	$ 0.86
Net income per limited partner unit-diluted	$ 2.84	$ 1.34	$ 2.28	$ 1.72	$ 0.86

	Year Ended December 31,				
	2014 (a)	2013 (a)	2012 (a)	2011 (a)	2010 (a)
	(Millions, except per unit amounts)				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 3,347	$ 3,046	$ 2,592	$ 2,157	$ 1,860
Total assets	$ 5,739	$ 4,567	$ 3,645	$ 2,955	$ 2,651
Accounts payable	$ 223	$ 275	$ 223	$ 414	$ 305
Long-term debt	$ 2,061	$ 1,590	$ 1,620	$ 747	$ 648
Partners' equity	$ 2,993	$ 1,985	$ 1,447	$ 1,299	$ 1,172
Noncontrolling interests	$ 33	$ 228	$ 189	$ 306	$ 288
Total equity	$ 3,026	$ 2,213	$ 1,636	$ 1,605	$ 1,460
Other Information:					
Cash distributions declared per unit	$ 3.0525	$ 2.8630	$ 2.7000	$ 2.5480	$ 2.4380
Cash distributions paid per unit	$ 3.0050	$ 2.8200	$ 2.6600	$ 2.5150	$ 2.4200

(a) Includes the effect of the following acquisitions prospectively from their respective dates of acquisition: (1) the Wattenberg pipeline acquired from Buckeye Partners, L.P. in January 2010; (2) an additional 5% interest in Collbran Valley Gas Gathering LLC, acquired from Delta Petroleum Company in February 2010; (3) the Raywood processing plant and Liberty gathering system acquired in June 2010; (4) an additional 50% interest in Black Lake Pipeline Company, or Black Lake, acquired from an affiliate of BP PLC in July 2010; (5) Atlantic Energy acquired from UGI

Corporation in July 2010; (6) Marysville Hydrocarbons Holdings, LLC acquired in December 2010; (7) the DJ Basin NGL fractionators acquired in March 2011; (8) our 100% owned Eagle Plant in August 2011; (9) the remaining 49.9% interest in East Texas acquired from DCP Midstream, LLC in January 2012; (10) a 10% ownership interest in the Texas Express Pipeline acquired from Enterprise Products Partners, L.P. in April 2012; (11) a 12.5% interest in the Enterprise fractionator and a 20% interest in the Mont Belvieu 1 fractionator, acquired from DCP Midstream, LLC in July 2012; (12) the Crossroads processing plant and 50% interest in CrossPoint Pipeline, LLC, acquired from Penn Virginia Resource Partners, L.P. in July 2012; (13) the O'Connor plant acquired from DCP Midstream, LLC in August 2013; (14) the Front Range pipeline acquired from DCP Midstream, LLC in August 2013 and (15) a 33.33% interest in each the Southern Hills and Sand Hills pipelines, acquired from DCP Midstream, LLC in March 2014.

(b) Includes the effect of the commodity derivative hedge instruments related to the Eagle Ford system, of which 33.33% was acquired from DCP Midstream, LLC in November 2012 and 46.67% was acquired in March 2013; the Goliad plant, of which 33.33% was acquired from DCP Midstream, LLC in December 2012 and 46.67% was acquired in March 2013 and the Southeast Texas storage business acquired from DCP Midstream, LLC in March 2012.

(c) Prior to the acquisition of the remaining 49.9% limited liability company interest in East Texas in January 2012, we hedged our proportionate ownership of East Texas. Results shown include the unhedged portion of East Texas owned by DCP Midstream, LLC. Our consolidated results depict 49.9% of East Texas unhedged in 2010 and 2011. Our consolidated results depict 100% of the Southeast Texas system unhedged in 2010 and 66.67% unhedged in 2011 and through March 2012 corresponding with DCP Midstream, LLC's ownership interest in Southeast Texas. Our consolidated results depict 100% of the Eagle Ford system unhedged in 2010 and through October 2012, and 66.67% from November 2012 through March 2013, and 20% from April 2013 through March 2014 corresponding with DCP Midstream, LLC's ownership interest in the Eagle Ford system.

(d) Includes our proportionate share of the earnings of our unconsolidated affiliates. Earnings include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities.

(e) Our consolidated financial statements include the historical assets, liabilities and results of operations of assets acquired from DCP Midstream, LLC, transactions between entities under common control, representing a change in reporting entity. Earnings for periods prior to these dropdowns are allocated to predecessor operations to derive net income allocable to limited partners. Accordingly, net income attributable to predecessor operations includes the net income attributable to the initial 33.33% interest in Southeast Texas prior to the date of our acquisition from DCP Midstream, LLC in January 2011; the remaining 66.67% interest in Southeast Texas and commodity derivative hedge instruments prior to the date of our acquisition from DCP Midstream, LLC in March 2012; the initial 33.33% interest in the Eagle Ford system prior to the date of our acquisition from DCP Midstream, LLC in November 2012; the additional 46.67% interest in the Eagle Ford system prior to the date of our acquisition from DCP Midstream, LLC in March 2013 and the Lucerne 1 plant prior to the date of our acquisition from DCP Midstream, LLC in March 2014.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our consolidated financial statements and notes included elsewhere in this annual report.

Overview

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

Our business is impacted by commodity prices, which we mitigate on an overall Partnership basis through a hedging program on volumes of throughput and sales of natural gas, NGLs and condensate through 2015. Various factors impact both commodity prices and volumes, and as indicated in Item 3. "Quantitative and Qualitative Disclosures about Market Risk," we have sensitivities to certain cash and non-cash changes in commodity prices. Commodity prices have recently declined substantially and experienced significant volatility during the latter part of 2014, as illustrated by the following table:

	Average For The Year Ended December 31,			Average For The Quarter Ended December 31,	Average For The Month Ended December 31,	Year Ended December 31, 2014	
	2012	2013	2014	2014	2014	Daily High	Daily Low
Commodity:							
NYMEX Natural Gas ($/MMBtu)	$ 2.82	$ 3.73	$ 4.26	$ 3.83	$ 3.51	$ 6.15	$ 2.89
NGLs ($/Gallon)	$ 1.02	$ 0.76	$ 0.89	$ 0.67	$ 0.51	$ 1.27	$ 0.45
Crude Oil ($/Bbl)	$ 94.16	$ 98.07	$ 93.03	$ 73.31	$ 59.29	$ 107.26	$ 53.27

The price of crude oil has continued to decline in the first part of 2015. If commodity prices remain weak for a sustained period, our natural gas throughput and NGL volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area, but in general, we have observed decreases in drilling activity with lower commodity prices. Despite recent short-term weakness, our long-term view is that commodity prices will be at levels that we believe will support continued growth in natural gas, condensate and NGL production.

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

Our direct commodity hedged positions mitigate a portion of our commodity price risk through 2017. Additionally, our fee-based business represents a significant portion of our estimated margins.

In addition to the U.S. financial markets, many businesses and investors continue to monitor global economic conditions. Uncertainty abroad may contribute to volatility in domestic financial and commodity markets.

Increased activity levels in liquids rich gas basins combined with access to capital markets at relatively low costs have historically enabled us to execute our multi-faceted growth strategy. Our multi-faceted growth strategy may take numerous forms such as organic build opportunities within our footprint, dropdown opportunities from DCP Midstream, LLC, joint venture opportunities, and third-party acquisitions. Dropdowns from DCP Midstream, LLC since the beginning of 2013 have totaled over $2 billion. In 2015, we will continue to prudently execute our multi-faceted growth strategy.

Some of our recent growth projects include the following:

- The Eagle Ford system completed construction of the Goliad 200 MMcf/d natural gas processing plant which was placed into service in February 2014.
- The Front Range pipeline, of which we own a 33.33% equity interest, was placed into service in February 2014.
- The O'Connor plant expansion to 160 MMcf/d was placed into service in March 2014.
- In March 2014, DCP Midstream, LLC contributed to us the Sand Hills pipeline, the Southern Hills pipeline and the remaining 20% interest in the Eagle Ford system, and we acquired from DCP Midstream, LLC the Lucerne 1 plant and the Lucerne 2 plant, which is currently under construction. These transactions are collectively referred to as the March 2014 Transactions.
- The expansion of Discovery's Keathley Canyon natural gas gathering pipeline system was placed into service in the first quarter of 2015.
- The construction of our Lucerne 2 plant is progressing on schedule and is expected to be completed in the second quarter of 2015.
- In January 2015, we acquired a 15% interest in the Panola intrastate NGL pipeline, an approximately 180-mile natural gas liquids pipeline system extending from points near Carthage, Texas to Mont Belvieu, Texas. The

pipeline is currently undergoing a 60-mile expansion to Lufkin, Texas, as well as construction of two additional pump stations, which is expected to be completed in the first quarter of 2016.

During the year ended December 31, 2014, we received net proceeds of $1,002 million from the issuance of our common units to the public and $712 million through public debt offerings of 30-year and five-year Senior Notes. Additionally, we issued $225 million of our common units to DCP Midstream, LLC as partial consideration for the March 2014 Transactions. In June 2014, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of $500 million, which became effective on July 11, 2014. The shelf registration statement allows us to issue additional common units from time to time under an equity distribution agreement we entered into in September 2014 with a group of financial institutions. During the year ended December 31, 2014, we had access to a Commercial Paper Program pursuant to which we had no amounts outstanding as of December 31, 2014. As of December 31, 2014, the unused capacity under the Amended and Restated Credit Agreement was $1,249 million, all of which was available for general working capital purposes, providing liquidity to continue to execute on our growth plans.

We raised our distribution for the fourth quarter of 2014 to $0.78 per unit, resulting in an approximately 6.5% increase in our quarterly distribution rate over the rate declared for the fourth quarter of 2013. The distribution reflects our business results as well as our recent execution on growth opportunities.

General Trends and Outlook

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

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

We expect to continue to pursue a multi-faceted growth strategy, capitalizing on organic expansion, maximizing dropdown opportunities provided by our partnership with DCP Midstream, LLC, and pursuing strategic third party acquisitions in order to grow our distributable cash flows.

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

Commodity Price Environment - Our business is impacted by commodity prices. If commodity prices remain weak for a sustained period, our natural gas throughput and NGL volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area, but in general, we have observed decreases in drilling activity with lower commodity prices. The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by drilling activity, which may be impacted by prevailing commodity prices. Commodity prices have declined substantially compared to historical periods and experienced significant volatility during the latter part of 2014, as illustrated in Item 1A. Risk Factors - “Current economic conditions may adversely affect producers’ drilling activity and transportation spending levels, which may in turn negatively impact our volumes and results of operations and our ability to make distributions to our unitholders.” Despite recent short-term weakness, our long-term view is that commodity prices will be at levels that we believe will support continued growth in natural gas, condensate and NGL production.

Natural Gas Gathering and Processing Margins - Except for our fee-based contracts, which may be impacted by throughput volumes, our natural gas gathering and processing profitability is dependent upon commodity prices, natural gas supply, and demand for natural gas, NGLs and condensate. Commodity prices, which are impacted by the balance between supply and demand, have historically been volatile. Throughput volumes could decline should commodity prices and drilling levels continue to experience weakness. Our long-term view is that as economic conditions improve, commodity prices should support continued natural gas production in the United States. During 2014, petrochemical demand remained stable for NGLs as NGLs were a lower cost feedstock when compared to crude oil derived feedstocks. We anticipate demand for NGLs by the petrochemical industry will continue in 2015 as chemical plants convert facilities from an oil-based feedstock to a NGL-based feedstock and as export facilities are brought into service. Although there can be, and has been, near-term volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to support increasing supply.

NGL Logistics - The volumes of NGLs transported on our pipelines, fractionated in our fractionation facilities and stored in our storage facility are dependent on the level of production of NGLs from processing plants connected to our assets. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the NGLs from the natural gas. As a result, we have experienced periods in the past, in which higher natural gas or lower NGL prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines, fractionation and storage facilities and, in turn, lower the NGL throughput on our assets.

Wholesale Propane Supply and Demand - Due to our multiple propane supply sources, propane supply contractual arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our propane distribution customers with reliable supplies of propane during peak demand periods of tight supply, usually in the winter months when their customers consume the most propane for heating.

Factors That May Significantly Affect Our Results

Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our consolidated financial statements have been adjusted to include the historical results of our Lucerne 1 plant, our initial 80% interest in the Eagle Ford system and the remaining 66.67% interest in Southeast Texas for all periods presented, similar to the pooling method. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity.

Natural Gas Services Segment

Our results of operations for our Natural Gas Services segment are impacted by (1) increases and decreases in the volume and quality of natural gas that we gather and transport through our systems, which we refer to as throughput, (2) the associated Btu content of our system throughput and our related processing volumes, (3) the prices of and relationship between commodities such as NGLs, crude oil and natural gas, (4) the operating efficiency and reliability of our processing facilities, (5) potential limitations on throughput volumes arising from downstream and infrastructure capacity constraints, (6) the terms of our processing contract arrangements with producers, and (7) increases and decreases in the volume, price and basis differentials of natural gas associated with our natural gas storage and pipeline assets, as well as our underlying derivatives associated with these assets. This is not a complete list of factors that may impact our results of operations but, rather, are those we believe are most likely to impact those results.

Throughput and operating efficiency generally are driven by wellhead production, plant recoveries, operating availability of our facilities, physical integrity and our competitive position on a regional basis, and more broadly by demand for natural gas, NGLs and condensate. Historical and current trends in the price changes of commodities may not be indicative of future trends. Throughput and prices are also driven by demand and take-away capacity for residue natural gas and NGLs.

Our processing contract arrangements can have a significant impact on our profitability and cash flow. Our actual contract terms are based upon a variety of factors, including natural gas quality, geographic location, the commodity pricing environment at the time the contract is executed, customer requirements and competition from other midstream service providers. Our gathering and processing contract mix and, accordingly, our exposure to natural gas, NGL and condensate prices, may change as a result of producer preferences, impacting our expansion in regions where certain types of contracts are more common as well as other market factors.

Our Natural Gas Services segment operating results are impacted by market conditions causing variability in natural gas, crude oil and NGL prices. The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by drilling activity, which may be impacted by prevailing commodity prices. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term, the growth and sustainability of our business depends on commodity prices being at levels sufficient to provide incentives and capital for producers to explore and produce natural gas.

The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close relationship. Due to our hedging program, changes in the relationship of the price of NGLs and crude oil may cause our commodity price exposure to vary, which we have attempted to capture in our commodity price sensitivities in "Quantitative and Qualitative Disclosures about Market Risk." Our results may also be impacted as a result of non-cash lower of cost or market inventory or imbalance adjustments, which occur when the market value of commodities decline below our carrying value.

The natural gas services business is highly competitive in our markets and includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport, store and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or natural gas liquids. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter in length of term and therefore must be renegotiated on a more frequent basis.

NGL Logistics Segment

Our NGL Logistics segment operating results are impacted by, among other things, the throughput volumes of the NGLs we transport on our NGL pipelines and the volumes of NGLs we fractionate and store. We transport, fractionate and store NGLs primarily on a fee basis. Throughput may be negatively impacted as a result of our customers operating their processing plants in ethane rejection mode, often as a result of low ethane prices relative to natural gas prices. Factors that impact the supply and demand of NGLs, as described above in our Natural Gas Services segment, may also impact the throughput and volume for our NGL Logistics segment.

Wholesale Propane Logistics Segment

Our Wholesale Propane Logistics segment operating results are impacted by our ability to provide our propane distribution customers with reliable supplies of propane. We use physical inventory, physical purchase agreements and financial derivative instruments, with DCP Midstream, LLC or third parties, which typically match the quantities of propane subject to fixed price sales agreements to mitigate our commodity price risk. Our results may also be impacted as a result of non-cash lower of cost or market inventory adjustments, which occur when the market value of propane declines below our carrying value. We generally recover lower of cost or market inventory adjustments in subsequent periods through the sale of inventory, or settlement of financial derivative instruments. There may be positive or negative impacts on sales volumes and gross margin from supply disruptions and weather conditions in the mid-Atlantic, upper midwestern and northeastern areas of the United States. Our annual sales volumes of propane may decline when these areas experience periods of milder weather in the winter months. Volumes may also be impacted by conservation and reduced demand in a recessionary environment. During times of reduced demand domestically, we may export propane.

The wholesale propane business is highly competitive in our market areas which include the mid-Atlantic, upper midwest and northeastern areas of the United States. Our competitors include major integrated oil and gas and energy companies, interstate and intrastate pipelines, as well as marketers and wholesalers.

Weather

The economic impact of severe weather may negatively affect the nation's short-term energy supply and demand, and may result in commodity price volatility. Additionally, severe weather may restrict or prevent us from fully utilizing our assets, by damaging our assets, interrupting utilities, and through possible NGL and natural gas curtailments downstream of our facilities, which restricts our production. These impacts may linger past the time of the actual weather event. Severe weather may also impact the supply availability and propane demand in our Wholesale Propane Logistics segment. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss in some instances, and in certain circumstances we have been unable to obtain insurance on commercially reasonable terms, if at all. We have recently experienced cold weather and freezing temperatures in certain regions where our assets are located but the effects did not have a material adverse impact on our operations.

Natural Gas Supply

The number of active oil and gas drilling rigs in the United States was 1,839 at December 31, 2014, compared to 1,756 at December 31, 2013. The number of active oil and gas drilling rigs in the United States has significantly decreased, from 1,930 at its recent peak in September 2014 to 1,542 as of January 30, 2015. (Source: Baker Hughes)

Capital Markets

Volatility in the capital markets may impact our business in multiple ways, including limiting our producers' ability to finance their drilling programs and limiting our ability to fund our operations through organic growth projects, dropdowns and acquisitions. These events may impact our counterparties' ability to perform under their credit or commercial obligations. Where possible, we have obtained additional collateral agreements, letters of credit from highly rated banks, or have managed credit lines to mitigate a portion of these risks.

Additionally, our access to the capital markets and our cost of doing business may be negatively impacted by the recent downgrade in our credit rating to below investment grade and may be impacted by further downgrades in our or DCP Midstream, LLC's credit ratings. See Item 1A. "Risk Factors" - "A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and independent third parties determine our credit ratings outside of our control."

Impact of Inflation

Inflation has been relatively low in the United States in recent years. However, the inflation rates impacting our business fluctuate throughout the broad economic and energy business cycles. Consequently, our costs for chemicals, utilities, materials and supplies, labor and major equipment purchases may increase during periods of general business inflation or periods of relatively high energy commodity prices.

Other

The above factors, including sustained deterioration in commodity prices and volumes, other market declines or a decline in our unit price, may negatively impact our results of operations, and may increase the likelihood of a non-cash impairment charge or non-cash lower of cost or market inventory adjustments.

Recent Events

On January 29, 2015, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.78 per unit, payable on February 13, 2015 to unitholders of record on February 9, 2015.

In January 2015, we entered into an agreement with an affiliate of Enterprise Products Partners L.P., or Enterprise, to acquire a 15% ownership interest in Panola Pipeline Company, LLC, or Panola. The anticipated total consideration of approximately $26 million includes our proportionate share in construction costs for an anticipated expansion of the existing Panola NGL pipeline. Originating near Carthage, Texas, the 10-inch diameter expansion will extend approximately 60 miles to Lufkin, Texas and will have an initial capacity of approximately 50 MBbls/d, with expansion to 100 MBbls/d possible following installation of additional pump stations. We, WGR Asset Holding Company LLC, which is an affiliate of Anadarko Petroleum Corporation, and MarkWest Panola Pipeline L.L.C. will each own a 15% interest in Panola. Enterprise will own a 55% interest in Panola and will construct and operate the expansion, which is expected to be in service in the first quarter of 2016.

On February 10, 2015, we, along with Williams Partners L.P., announced that the new extended Discovery natural gas gathering pipeline system is now flowing natural gas. The Keathley Canyon Connector, a 20-inch diameter, 209-mile subsea natural gas gathering pipeline is capable of gathering more than 400 MMcf/d of natural gas, and originates in the southeast portion of the Keathley Canyon protraction area of the Gulf of Mexico, and terminates into Discovery's 30-inch diameter mainline near South Timbalier Block 283.

Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, we no longer have access to the Commercial Paper Program. Our available liquidity under the Commercial Paper Program will be replaced with borrowings under our Amended and Restated Credit Agreement. Additionally, as a result of this ratings action, interest rates and fees under our Amended and Restated Credit Agreement have increased.

Subsequent to December 31, 2014, DCP Midstream, LLC's credit rating has been lowered below investment grade. As a result of this ratings action, DCP Midstream, LLC no longer has access to its Commercial Paper Program. DCP Midstream, LLC's available liquidity under its Commercial Paper Program will be replaced with borrowings under its Amended and Restated Revolving Credit Agreement. As a result of this ratings action, interest rates and fees under DCP Midstream, LLC's Amended and Restated Revolving Credit Agreement have increased.

In January 2015, DCP Midstream, LLC announced a reduction in force affecting approximately 20 percent of its corporate staff functions. With this corporate restructuring, DCP Midstream, LLC will also close or reduce the workforce of certain regional offices.

Our Operations

We manage our business and analyze and report our results of operations on a segment basis. Our operations are divided into our Natural Gas Services segment, our NGL Logistics segment and our Wholesale Propane Logistics segment.

Natural Gas Services Segment

Results of operations from our Natural Gas Services segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported, stored and sold through our gathering, processing and pipeline systems; the volumes of NGLs and condensate sold; and the level of our realized natural gas, NGL and condensate prices. We generate our revenues and our gross margin for our Natural Gas Services segment principally from contracts that contain a combination of the following arrangements:

- *Fee-based arrangements* - Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, transporting or storing natural gas. Our fee-based arrangements include natural gas arrangements pursuant to which we obtain natural gas at the wellhead or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.

- *Percent-of-proceeds/liquids arrangements* - Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas, NGLs and condensate based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas, NGLs and condensate, regardless of the actual amount of the sales proceeds we receive. We keep the difference between the proceeds received and the amount remitted back to the producer. Under percent-of-liquids arrangements, we do not keep any amounts related to residue natural gas proceeds and only keep amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. Certain of these arrangements may also result in the producer retaining title to all or a portion of the residue natural gas and/or the NGLs, in lieu of us returning sales proceeds to the producer. Additionally, these arrangements may include fee-based components. Our revenues under percent-of-proceeds arrangements relate directly with the price of natural gas, NGLs and condensate. Our revenues under percent-of-liquids arrangements relate directly to the price of NGLs and condensate.

In addition to the above contract types, we have keep-whole arrangements, which are estimated to generate an insignificant portion of our gross margin. Discovery, in which we have a 40% interest, also has keep-whole arrangements. Under the terms of a keep-whole processing contract, natural gas is gathered from the producer for processing, the NGLs and condensate are sold and the residue natural gas is returned to the producer with a Btu content equivalent to the Btu content of the natural gas gathered. This arrangement keeps the producer whole to the thermal value of the natural gas received. Under this type of contract, we are exposed to the frac spread. The frac spread is the difference between the value of the NGLs and condensate extracted from processing and the value of the Btu equivalent of the residue natural gas. We benefit in periods when NGL and condensate prices are higher relative to natural gas prices when that frac spread exceeds our operating costs. Fluctuations in commodity prices are expected to continue to impact the operating costs of these entities.

The natural gas supply for our gathering pipelines and processing plants is derived primarily from natural gas wells located in Arkansas, Colorado, Louisiana, Michigan, Oklahoma, Texas, Wyoming and the Gulf of Mexico. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. We had one supplier of natural gas representing 10% or more of our total natural gas supply during the year ended December 31, 2014. We actively seek new supplies of natural gas, both to offset natural declines in the production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage, or by obtaining natural gas that has been directly received or released from other gathering systems.

We sell natural gas to marketing affiliates of natural gas pipelines, integrated oil companies, DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. The NGLs extracted from the natural gas at our processing plants are sold at market index prices to DCP Midstream, LLC or its affiliates, or to third parties. In addition, under our merchant arrangements, various DCP Midstream LLC affiliates purchase natural gas from third parties at wellheads, pipeline interconnect and pooling points, as well as residue gas from our processing plants, and then resell the aggregated natural gas to third parties.

We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. As a service to our customers, we may enter into physical fixed price natural gas purchases and sales, utilizing financial derivatives to swap this fixed price risk back to market index. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage.

NGL Logistics Segment

Our pipelines, fractionation facilities and storage facility provide transportation, fractionation and storage services for customers, primarily on a fee basis. We have entered into contractual arrangements with DCP Midstream, LLC and others that generally require customers to pay us to transport or store NGLs pursuant to a fee-based rate that is applied to volumes. These contractual arrangements may require our customers to commit a minimum level of volumes to our pipelines and facilities, thereby mitigating our exposure to volume risk. However, the results of operations for this business segment are generally dependent upon the volume of product transported, fractionated or stored and the level of fees charged to customers. We do not take title to the products transported on our NGL pipelines, fractionated in our fractionation facilities or stored in our storage facility; rather, the customer retains title and the associated commodity price risk. DCP Midstream, LLC provides 100% of volumes transported on the Wattenberg and Seabreeze pipelines. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the NGLs from the natural gas. As a result, we have experienced periods in the past, in which higher natural gas or lower NGL prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines and, in turn, lower the NGL throughput on our assets. DCP Midstream, LLC, the largest gatherer and processor in the DJ Basin, delivers NGLs to our fractionation facilities under a long-term fractionation agreement. Our storage facility in Marysville, Michigan provides storage and related services primarily to regional refining and petrochemical companies and NGL marketers operating in the liquid hydrocarbons industry.

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the mid-Atlantic, upper midwest and northeastern United States. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the mid-Atlantic, midwest and the northeastern areas of the United States. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our four primary suppliers of propane, one of which is an affiliated entity, represented approximately 80% of our propane supplied during the year ended December 31, 2014. We primarily sell propane on a wholesale basis to propane distributors who in turn resell propane to their customers.

Due to our multiple propane supply sources, annual and long-term propane supply purchase arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our propane distribution customers with reliable supplies of propane during periods of tight supply, such as the winter months when their customers generally consume the most propane for home heating. In particular, we generally offer our customers the ability to obtain propane supply volumes from us in the winter months that are generally significantly greater than their purchases of propane from us in the summer. We believe these factors allow us to maintain our generally favorable relationships with our customers.

We manage our wholesale propane margins by selling propane to propane distributors under annual sales agreements negotiated each spring which specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. Our portfolio of multiple supply sources and storage capabilities allows us to actively manage our propane supply purchases and to lower the aggregate cost of supplies. Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may continue to periodically recognize non-cash lower of cost or market inventory adjustments. In addition, we may use financial derivatives to manage the value of our propane inventories.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) volumes; (2) gross margin and segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) adjusted EBITDA, (5) adjusted segment EBITDA; and (6) distributable cash flow. Gross margin, segment gross margin, adjusted EBITDA, adjusted segment EBITDA, and distributable cash flow are not measures under accounting principles generally accepted in the United States of America, or GAAP. To the extent permitted, we present certain non-GAAP measures and reconciliations of those measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. These non-GAAP measures may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

Volumes - We view throughput and storage volumes for our Natural Gas Services segment and our NGL Logistics segment, and sales volumes for our Wholesale Propane Logistics segment as important factors affecting our profitability. We gather and transport some of the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of our natural gas processing plants, we must continually obtain new supplies of natural gas and NGLs. Our ability to maintain existing supplies of natural gas and NGLs and obtain new supplies are impacted by: (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines; and (2) our ability to compete for volumes from successful new wells in other areas. The throughput volumes of NGLs and gas on our pipelines are substantially dependent upon the quantities of NGLs and gas produced at our processing plants, as well as NGLs and gas produced at other processing plants that have pipeline connections with our NGL and gas pipelines. We regularly monitor producer activity in the areas we serve and in which our pipelines are located, and pursue opportunities to connect new supply to these pipelines. We also monitor our inventory in our NGL and gas storage facilities, as well as overall demand for storage based on seasonal patterns and other market factors such as weather and overall demand.

Reconciliation of Non-GAAP Measures

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

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

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

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

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

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

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

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

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

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

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

Reconciliation of Non-GAAP Measures	Year Ended December 31, 2014	2013	2012
		(Millions)	
Reconciliation of net income attributable to partners to gross margin:			
Net income attributable to partners	$ 423	$ 200	$ 216
Interest expense	86	52	42
Income tax expense	6	8	1
Operating and maintenance expense	216	215	197
Depreciation and amortization expense	110	95	91
General and administrative expense	64	63	75
Other expense	3	8	—
Earnings from unconsolidated affiliates	(75)	(33)	(26)
Net income attributable to noncontrolling interests	14	17	13
Gross margin	$ 847	$ 625	$ 609
Non-cash commodity derivative mark-to-market (a)	$ 86	$ (37)	$ 21
Reconciliation of segment net income attributable to partners to segment gross margin:			
Natural Gas Services segment:			
Segment net income attributable to partners	$ 455	$ 213	$ 256
Operating and maintenance expense	189	184	166
Depreciation and amortization expense	101	87	83
Other expense	2	1	—
Earnings from unconsolidated affiliates	(5)	(1)	(15)
Net income attributable to noncontrolling interests	14	17	13
Segment gross margin	$ 756	$ 501	$ 503
Non-cash commodity derivative mark-to-market (a)	$ 89	$ (36)	$ 20
NGL Logistics segment:			
Segment net income attributable to partners	$ 119	$ 79	$ 53
Operating and maintenance expense	16	16	16
Depreciation and amortization expense	7	6	6
Other expense	1	3	—
Earnings from unconsolidated affiliates	(70)	(32)	(11)
Segment gross margin	$ 73	$ 72	$ 64
Wholesale Propane Logistics segment:			
Segment net income attributable to partners	$ 5	$ 31	$ 25
Operating and maintenance expense	11	15	15
Depreciation and amortization expense	2	2	2
Other expense	—	4	—
Segment gross margin	$ 18	$ 52	$ 42
Non-cash commodity derivative mark-to-market (a)	$ (3)	$ (1)	$ 1

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

	Year Ended December 31,		
	2014	2013	2012
		(Millions)	
Reconciliation of net income attributable to partners to adjusted segment EBITDA:			
Natural Gas Services segment:			
Segment net income attributable to partners (a)	$ 455	$ 213	$ 256
Non-cash commodity derivative mark-to-market	(89)	36	(20)
Depreciation and amortization expense	101	87	83
Noncontrolling interest on depreciation and income tax	(3)	(6)	(7)
Adjusted Segment EBITDA	$ 464	$ 330	$ 312
NGL Logistics segment:			
Segment net income attributable to partners	$ 119	$ 79	$ 53
Depreciation and amortization expense	7	6	6
Adjusted Segment EBITDA	$ 126	$ 85	$ 59
Wholesale Propane Logistics segment:			
Segment net income attributable to partners (b)	$ 5	$ 31	$ 25
Non-cash commodity derivative mark-to-market	3	1	(1)
Depreciation and amortization expense	2	2	2
Adjusted Segment EBITDA	$ 10	$ 34	$ 26

(a) Includes $11 million, $2 million, and $4 million in lower of cost or market adjustments for the years ended December 31, 2014, 2013 and 2012, respectively.
(b) Includes $13 million, $2 million, and $15 million in lower of cost or market adjustments for the years ended December 31, 2014, 2013 and 2012, respectively.

Operating and Maintenance and General and Administrative Expense - Operating and maintenance expenses are costs associated with the operation of a specific asset and are primarily comprised of direct labor, ad valorem taxes, repairs and maintenance, lease expenses, utilities and contract services. These expenses fluctuate depending on the activities performed during a specific period. General and administrative expenses are as follows:

	Year Ended December 31,		
	2014	2013	2012
		(Millions)	
General and administrative expense	$ 17	$ 17	$ 17
General and administrative expense - affiliate:			
Services/Omnibus Agreement	41	29	26
Other - DCP Midstream, LLC	6	17	32
Total affiliate	47	46	58
Total	$ 64	$ 63	$ 75

We have entered into a services agreement, as amended, or the Services Agreement, with DCP Midstream, LLC. Under the Services Agreement, which replaced the Omnibus Agreement on February 14, 2013, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee under the Services Agreement for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. Except with respect to the annual fee, there is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for other expenses and expenditures incurred or payments made on our behalf. In the event we acquire assets or our business otherwise expands, the annual fee under the Services Agreement is subject to adjustment based on the nature and extent of general and administrative services performed by DCP Midstream, LLC, as well as an annual adjustment based on changes to the Consumer Price Index.

On March 31, 2014, the annual fee payable under the Services Agreement was increased by approximately $15 million, prorated for the remainder of the calendar year, to $44 million. The increase was predominantly attributable to additional general and administrative expenses previously incurred directly by the Eagle Ford system being reallocated to the Services Agreement in connection with the contribution of the remaining 20% interest in the Eagle Ford system to us, bringing our ownership to 100%.

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

In addition to the fees paid pursuant to the Services Agreement, we incurred allocated expenses, including executive compensation, insurance and internal audit fees with DCP Midstream, LLC of $2 million, $2 million and $1 million for the years ended December 31, 2014, 2013 and 2012, respectively. The Lucerne 1 plant incurred $1 million in general and administrative expenses directly from DCP Midstream, LLC for the years ended December 31, 2013, and 2012. The Eagle Ford system incurred $4 million, $14 million and $27 million in general and administrative expenses directly from DCP Midstream, LLC for the years ended December 31, 2014, 2013 and 2012, respectively, before the reallocation of the Eagle Ford system to the Services Agreement on March 31, 2014. For the year ended December 31, 2012, Southeast Texas incurred $3 million in general and administrative expenses directly from DCP Midstream, LLC, before the addition of Southeast Texas to the Omnibus Agreement in March 2012.

We also incurred third party general and administrative expenses, which were primarily related to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, due diligence and acquisition costs, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and director compensation.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2014, 2013 and 2012. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Year Ended December 31,			Variance 2014 vs. 2013		Variance 2013 vs. 2012	
	2014 (a)	2013 (a)(b)	2012 (a)(b)(c)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues (d):							
Natural Gas Services	$ 3,163	$ 2,598	$ 2,345	$ 565	22 %	$ 253	11 %
NGL Logistics	73	73	64	—	— %	9	14 %
Wholesale Propane Logistics	406	380	415	26	7 %	(35)	(8)%
Total operating revenues	3,642	3,051	2,824	591	19 %	227	8 %
Gross margin (e):							
Natural Gas Services	756	501	503	255	51 %	(2)	— %
NGL Logistics	73	72	64	1	1 %	8	13 %
Wholesale Propane Logistics	18	52	42	(34)	(65)%	10	24 %
Total gross margin	847	625	609	222	36 %	16	3 %
Operating and maintenance expense	(216)	(215)	(197)	1	— %	18	9 %
Depreciation and amortization expense	(110)	(95)	(91)	15	16 %	4	4 %
General and administrative expense	(64)	(63)	(75)	1	2 %	(12)	(16)%
Other expense	(3)	(8)	—	(5)	(63)%	8	100 %
Earnings from unconsolidated affiliates (f)	75	33	26	42	127 %	7	27 %
Interest expense	(86)	(52)	(42)	34	65 %	10	24 %
Income tax expense	(6)	(8)	(1)	(2)	(25)%	7	700 %
Net income attributable to noncontrolling interests	(14)	(17)	(13)	(3)	(18)%	4	31 %
Net income attributable to partners	$ 423	$ 200	$ 216	$ 223	112 %	$ (16)	(7)%
Other data:							
Non-cash commodity derivative mark-to-market	$ 86	$ (37)	$ 21	$ 123	332 %	$ (58)	(276)%
Natural gas throughput (MMcf/d) (g)	2,604	2,307	2,359	297	13 %	(52)	(2)%
NGL gross production (Bbls/d) (g)	157,722	121,970	115,945	35,752	29 %	6,025	5 %
NGL pipelines throughput (Bbls/d) (g)	184,706	89,361	78,508	95,345	107 %	10,853	14 %
Propane sales volume (Bbls/d)	18,335	19,553	19,111	(1,218)	(6)%	442	2 %

(a) Includes the results of our Lucerne 1 plant, retrospectively adjusted, which we acquired on March 28, 2014.
(b) Includes the results of an 80% interest in the Eagle Ford system, retrospectively adjusted. We acquired a 46.67% interest on March 28, 2013 and a 33.33% interest on November 2, 2012.
(c) Includes our 100% interest in Southeast Texas, retrospectively adjusted. We acquired the remaining 66.67% interest on March 30, 2012.
(d) Operating revenues include the impact of commodity derivative activity.
(e) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs. Segment gross margin for each segment consists of total operating revenues for that segment, including commodity derivative activity, less commodity purchases for that segment. Please read “Reconciliation of Non-GAAP Measures” above.
(f) Includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 40% ownership of Discovery, our 33.33% ownership of each of the Sand Hills, Southern Hills and Front Range NGL

pipelines, 20% ownership of the Mont Belvieu 1 fractionator, 12.5% ownership of the Mont Belvieu Enterprise fractionator and 10% ownership of the Texas Express NGL pipeline. Earnings for Discovery, Sand Hills, Southern Hills, Front Range, Mont Belvieu 1 and Texas Express include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities.

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

Year Ended December 31, 2014 vs. Year Ended December 31, 2013

Total Operating Revenues — Total operating revenues increased $591 million in 2014 compared to 2013 as a result of the following:

- $565 million increase for our Natural Gas Services segment primarily due to higher volumes and improved NGL recoveries at our Eagle Ford system, an increase as a result of commodity derivative activity, increased commodity prices and an increase in fee revenue, partially offset by lower volumes across certain assets; and

- $26 million increase for our Wholesale Propane Logistics segment primarily due to higher propane prices throughout the year and a new storage agreement, partially offset by lower volumes and a decrease as a result of commodity derivative activity.

- Total operating revenues for our NGL Logistics segment remained constant in 2014 compared to 2013.

Gross Margin — Gross margin increased $222 million in 2014 compared to 2013, primarily as a result of the following:

- $255 million increase for our Natural Gas Services segment, primarily related to an increase as a result of commodity derivative activity, the operation of our O'Connor plant in our DJ Basin system, higher volumes, improved NGL recoveries and greater efficiencies at our Eagle Ford system, a favorable contractual producer settlement and higher unit margins on our storage assets; partially offset by an increase in non-cash lower of cost or market inventory adjustments, lower volumes across certain assets and a change in the contract structure at our Lucerne 1 plant.

  This increase was partially offset by:

- $34 million decrease for our Wholesale Propane Logistics segment primarily due to an increase in non-cash lower of cost or market inventory adjustments, decreased unit margins, a decrease in volumes and a decrease as a result of commodity derivative activity.

- Gross margin for our NGL Logistics segment remained relatively constant as a result of increased throughput on certain of our pipelines, offset by lower customer inventory and related fees at our NGL storage facility.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2014 compared to 2013 primarily as a result of growth, in part due to the operation of the O'Connor and Goliad plants, in our Natural Gas Services segment, partially offset by a change in the structure of our marine terminal lease in our Wholesale Propane Logistics segment.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2014 compared to 2013 primarily as a result of growth in our operations.

General and Administrative Expense — General and administrative expense remained relatively constant in 2014 compared to 2013.

Other Expense — Other expense in 2014 and 2013 represents a write off of construction work in progress due to discontinued projects.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2014 compared to 2013 primarily as a result of the March 2014 contribution of Sand Hills and Southern Hills and increased volumes at Front Range and Texas Express due to the amount of time in service in our NGL Logistics segment and changes in contract mix at Discovery in our Natural Gas Services segment, partially offset by lower volumes due to maintenance and unfavorable location pricing at our Mont Belvieu fractionators in our NGL Logistics segment.

Interest Expense — Interest expense increased in 2014 compared to 2013 as a result of higher outstanding debt balances associated with the growth in our operations.

Income Tax Expense — Income tax expense decreased in 2014 compared to 2013 primarily due to higher expense in 2013 attributable to an increase in the ownership of certain assets.

Net Income Attributable to Noncontrolling Interests — Net income attributable to noncontrolling interests decreased in 2014 compared to 2013 primarily as a result of the contribution of the remaining 20% interest in the Eagle Ford system in March 2014, partially offset by favorable cumulative producer settlements, higher volumes and improved NGL recoveries at our Eagle Ford system prior to the March transaction.

Year Ended December 31, 2013 vs. Year Ended December 31, 2012

Total Operating Revenues — Total operating revenues increased $227 million in 2013 compared to 2012 as a result of the following:

- $253 million increase for our Natural Gas Services segment primarily due to higher volumes, an increase attributable to commodity prices and an increase in fee revenue, partially offset by a decrease in commodity derivative activity related to hedge settlement timing on our natural gas storage and pipeline assets; and
- $9 million increase for our NGL Logistics segment primarily due to increased throughput on certain of our pipelines and increased activity at our NGL storage facility.

These increases were partially offset by:

- $35 million decrease for our Wholesale Propane Logistics segment primarily due to lower propane prices and commodity derivative activity related to favorable hedge settlement timing in 2012, partially offset by increased volumes.

Gross Margin — Gross margin increased $16 million in 2013 compared to 2012, primarily as a result of the following.

- $10 million increase for our Wholesale Propane Logistics segment, primarily due to increased unit margins and exporting of propane, partially offset by a decrease related to commodity derivative activity. 2012 results reflect a non-cash lower of cost or market inventory adjustment and reduced demand; and
- $8 million increase for our NGL Logistics segment as a result of increased throughput on certain of our pipelines and increased activity at our NGL storage facility.

These increases were partially offset by:

- $2 million decrease for our Natural Gas Services segment, primarily related to decreased commodity derivative activity, lower commodity prices and lower volumes across certain assets, partially offset by improved NGL recoveries and an annual minimum volume commitment fee at our Eagle Ford system, a decrease in a lower of cost or market adjustment recognized in 2013 and extensive turnaround activity at our East Texas system in 2012.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2013 compared to 2012 primarily as a result of growth and asset reliability expenditures.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2013 compared to 2012 primarily as a result of growth in our business, partially offset by a change in the estimated depreciable lives of our fixed assets in the second quarter of 2012. The key contributing factors to the change in depreciable lives was an increase in the producers' estimated remaining economically recoverable reserves, resulting from widespread application of techniques, such as hydraulic fracturing and horizontal drilling, that improve commodity production in the regions our assets serve. Advances in extraction processes, along with improved technology used to locate commodity reserves, is giving producers greater access to unconventional commodities.

General and Administrative Expense — General and administrative expense decreased in 2013 compared to 2012 primarily due to the difference in the Eagle Ford system's ownership structure in each period.

Other Expense — Other expense represents a write off of approximately $8 million in construction work in progress in 2013 due to discontinued projects.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2013 compared to 2012 primarily as a result of increased volumes in our NGL Logistics segment, in part due to the acquisition of the Mont Belvieu fractionators in July 2012. 2012 results for the Mont Belvieu 1 fractionator reflect lower margin and higher operating expenses. This increase was partially offset by lower NGL prices and volumes, a non-cash write off of fixed assets, a third party outage and higher operating expenses at Discovery. 2012 results for Discovery reflect the favorable settlement of commercial disputes.

Interest Expense — Interest expense increased in 2013 compared to 2012 as a result of higher outstanding debt balances.

Income Tax Expense — Income tax expense increased in 2013 compared to 2012 primarily due to growth in our business.

Net Income Attributable to Noncontrolling Interests — Net income attributable to noncontrolling interests increased in 2013 compared to 2012, primarily as a result of higher volumes, improved NGL recoveries and an annual minimum volume commitment fee at our Eagle Ford system.

Results of Operations — Natural Gas Services Segment

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

	Year Ended December 31,			Variance 2014 vs. 2013		Variance 2013 vs. 2012	
	2014 (a)	2013 (a)(b)	2012 (a)(b)(c)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of natural gas, NGLs and condensate	$ 2,737	$ 2,383	$ 2,123	$ 354	15 %	$ 260	12 %
Transportation, processing and other	269	199	170	70	35 %	29	17 %
Gains from commodity derivative activity	157	16	52	141	881 %	(36)	(69)%
Total operating revenues	3,163	2,598	2,345	565	22 %	253	11 %
Purchases of natural gas and NGLs	(2,407)	(2,097)	(1,842)	310	15 %	255	14 %
Segment gross margin (d)	756	501	503	255	51 %	(2)	— %
Operating and maintenance expense	(189)	(184)	(166)	5	3 %	18	11 %
Depreciation and amortization expense	(101)	(87)	(83)	14	16 %	4	5 %
Other expense	(2)	(1)	—	1	100 %	1	100 %
Earnings from unconsolidated affiliates (e)	5	1	15	4	400 %	(14)	(93)%
Segment net income	469	230	269	239	104 %	(39)	(14)%
Segment net income attributable to noncontrolling interests	(14)	(17)	(13)	(3)	(18)%	4	31 %
Segment net income attributable to partners	$ 455	$ 213	$ 256	$ 242	114 %	$ (43)	(17)%
Other data:							
Non-cash commodity derivative mark-to-market	$ 89	$ (36)	$ 20	$ 125	347 %	$ (56)	(280)%
Natural gas throughput (MMcf/d) (f)	2,604	2,307	2,359	297	13 %	(52)	(2)%
NGL gross production (Bbls/d) (f)	157,722	121,970	115,945	35,752	29 %	6,025	5 %

(a) Includes the results of our Lucerne 1 plant, retrospectively adjusted, which we acquired on March 28, 2014.
(b) Includes the results of an 80% interest in the Eagle Ford system, retrospectively adjusted. We acquired a 46.67% interest on March 28, 2013 and a 33.33% interest on November 2, 2012.
(c) Includes our 100% interest in Southeast Texas, retrospectively adjusted. We acquired the remaining 66.67% interest on March 30, 2012.
(d) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas and NGLs. Please read "Reconciliation of Non-GAAP Measures" above.
(e) Includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 40% ownership of Discovery. Earnings for Discovery include the amortization of the net difference between the carrying amount of our investment and the underlying equity of the entity.
(f) Includes our share, based on our ownership percentage, of the throughput volumes and NGL production of

unconsolidated affiliates.

Year Ended December 31, 2014 vs. Year Ended December 31, 2013

Total Operating Revenues — Total operating revenues increased $565 million in 2014 compared to 2013, primarily as a result of the following:

- $246 million increase primarily attributable to higher volumes and improved NGL recoveries at our Eagle Ford system, in part due to the operation of our Eagle and Goliad plants. This increase was partially offset by lower volumes across certain assets;
- $141 million increase as a result of commodity derivative activity attributable to unrealized commodity derivative gains in 2014 compared to unrealized commodity derivative losses in 2013 for a net increase of $125 million due to movements in forward prices of commodities, and an increase in realized cash settlement gains in 2014 compared to 2013 of $16 million;
- $137 million increase attributable to increased commodity prices, which impact both sales and purchases, before the impact of commodity derivative activity;
- $73 million increase attributable to increased prices related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems; and
- $70 million increase in fee revenue primarily attributable to higher volumes at our Eagle Ford system, as well as the operation of our O'Connor plant in our DJ Basin system and a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation.

These increases were partially offset by:

- $53 million decrease attributable to a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation; and
- $49 million decrease attributable to decreased volumes related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $310 million in 2014 compared to 2013 primarily as a result of increased commodity prices, increased volumes at our Eagle Ford system and an increase in non-cash lower of cost or market inventory adjustments to $11 million in 2014 from $2 million in 2013. These increases were partially offset by decreased volumes at our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems, lower volumes across certain assets and a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation.

Segment Gross Margin — Segment gross margin increased $255 million in 2014 compared to 2013, primarily as a result of the following:

- $141 million increase as a result of commodity derivative activity as discussed above;
- $105 million increase attributable to the operation of our O'Connor plant in our DJ Basin system, higher volumes, improved NGL recoveries and greater efficiencies at our Eagle Ford system, and a favorable contractual producer settlement; partially offset by lower volumes across certain assets and a change in the contract structure at our Lucerne 1 plant; and
- $18 million increase attributable to higher unit margins on our storage assets.

These increases were partially offset by:

- $9 million decrease due to an increase in non-cash lower of cost or market inventory adjustments to $11 million in 2014 from $2 million in 2013.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2014 compared to 2013 primarily as a result of growth in our operations, in part due to the operation of our O'Connor and Goliad plants.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2014 compared to 2013 primarily as a result of growth in our operations.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2014 compared to 2013 primarily as a result of changes in contract mix at Discovery.

Segment Net Income Attributable to Noncontrolling Interests - Segment net income attributable to noncontrolling interests decreased in 2014 compared to 2013, primarily as a result of the contribution of the remaining 20% interest in the Eagle Ford system in March 2014, partially offset by favorable cumulative producer settlements, higher volumes and improved NGL recoveries at our Eagle Ford system prior to the March transaction.

Natural Gas Throughput - Natural gas throughput increased in 2014 compared to 2013 primarily as a result of higher volumes at our Eagle Ford system in part due to the operation of our Goliad plant, and our DJ Basin system in part due to the operation of our O'Connor plant. This increase was partially offset by lower volumes across certain assets.

NGL Gross Production - NGL production increased in 2014 compared to 2013 primarily as a result of higher volumes at our Eagle Ford system in part due to the operation of our Goliad plant, and our DJ Basin system in part due to the operation of our O'Connor plant. This increase was partially offset by lower volumes across certain assets.

Year Ended December 31, 2013 vs. Year Ended December 31, 2012

Total Operating Revenues — Total operating revenues increased $253 million in 2013 compared to 2012, primarily as a result of the following:

- $209 million increase primarily attributable to higher volumes and improved NGL recoveries at our Eagle Ford and East Texas systems, partially offset by lower volumes across certain assets, primarily our Southeast Texas system, and a plant turnaround at our Eagle Ford system. 2012 results reflect extensive turnaround activity at our East Texas system**;**
- $183 million increase attributable to increased natural gas prices;
- $83 million increase attributable to increased prices related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems; and
- $29 million increase in fee revenue primarily attributable to higher volumes at our Eagle Ford and East Texas systems, and the operation of our O'Connor plant.

These increases were partially offset by:

- $145 million decrease attributable to decreased NGL prices;
- $70 million decrease attributable to decreased volumes related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems; and
- $36 million decrease related to commodity derivative activity. This includes unrealized commodity derivative losses in 2013 compared to gains in 2012 due to movements in forward prices of commodities for a net impact of $56 million, partially offset by an increase in realized cash settlement gains in 2013 compared to 2012 of $20 million.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $255 million in 2013 compared to 2012 primarily as a result of higher natural gas prices, increased volumes at our Eagle Ford and East Texas systems and extensive turnaround activity at our East Texas system in 2012, partially offset by decreased NGL prices, decreased volumes related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems, lower volumes across certain gathering and processing assets, primarily our Southeast Texas system, and a plant turnaround at our Eagle Ford system.

Segment Gross Margin — Segment gross margin decreased $2 million in 2013 compared to 2012, primarily as a result of the following:

- $36 million decrease related to commodity derivative activity as discussed above;

- $24 million decrease as a result of lower NGL prices, which primarily reflects the unhedged portion of the Eagle Ford system associated with DCP Midstream, LLC's ownership during the year ended December 31, 2013; and
- $2 million decrease attributable to lower volumes associated with our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems; partially offset by a decrease in the lower of cost or market adjustment recognized in 2013 as compared to 2012.

These decreases were partially offset by:

- $60 million increase as a result of growth from the operation of our fee-based O'Connor plant, higher volumes and improved NGL recoveries at our Eagle Ford and East Texas systems and an annual minimum volume commitment fee at our Eagle Ford system, partially offset by lower volumes across certain assets. 2012 results reflected extensive turnaround activity at our East Texas system.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2013 compared to 2012 primarily as a result of growth and asset reliability expenditures.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2013 compared to 2012 primarily as a result of growth in our business, offset by a change in the estimated depreciable lives of our fixed assets in the second quarter of 2012. The key contributing factors to the change in depreciable lives was an increase in the producers' estimated remaining economically recoverable reserves, resulting from widespread application of techniques, such as hydraulic fracturing and horizontal drilling, that improve commodity production in the regions our assets serve. Advances in extraction processes, along with improved technology used to locate commodity reserves, is giving producers greater access to unconventional commodities.

Other Expense — Other expense represents a write off of approximately $1 million in construction work in progress in 2013 due to discontinued projects.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, primarily representing our 40% ownership of Discovery, decreased in 2013 compared to 2012 as a result of lower NGL prices, reduced throughput volumes, a non-cash write off of fixed assets, a third party outage and higher operating expenses, partially offset by a foreign currency translation gain related to the Keathley Canyon project. 2012 results reflect the favorable settlement of commercial disputes. Commodity derivative activity associated with our exposure on our unconsolidated affiliates is included in segment gross margin.

Segment Net Income Attributable to Noncontrolling Interests - Segment net income attributable to noncontrolling interests increased in 2013 compared to 2012, primarily as a result of higher volumes, improved NGL recoveries and an annual minimum volume commitment fee at our Eagle Ford system.

Natural Gas Throughput - Natural gas throughput decreased slightly in 2013 compared to 2012 primarily as a result of lower volumes across certain assets, partially offset by higher volumes due to the operation of our 100% owned Eagle and O'Connor plants in 2013, and extensive turnaround activity at our East Texas system in 2012.

NGL Gross Production - NGL production increased in 2013 compared to 2012 primarily as a result of higher volumes due to the operation of our 100% owned Eagle and O'Connor plants, and improved NGL recoveries at our Eagle Ford and East Texas systems, partially offset by lower volumes across certain assets. 2012 results reflect lower volumes as certain of our assets were required to curtail NGL production due to a downstream outage and extensive turnaround activity at our East Texas system.

Results of Operations — NGL Logistics Segment

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

	Year Ended December 31,			Variance 2014 vs. 2013		Variance 2013 vs. 2012	
	2014	2013	2012	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of NGLs	$ —	$ 1	$ —	$ (1)	(100)%	$ 1	100%
Transportation, processing and other	73	72	64	1	1 %	8	13%
Total operating revenues	73	73	64	—	— %	9	14%
Purchases of NGLs	—	(1)	—	(1)	(100)%	1	100%
Segment gross margin (a)	73	72	64	1	1 %	8	13%
Operating and maintenance expense	(16)	(16)	(16)	—	— %	—	—%
Depreciation and amortization expense	(7)	(6)	(6)	1	17 %	—	—%
Other expense	(1)	(3)	—	(2)	(67)%	3	100%
Earnings from unconsolidated affiliates (b)	70	32	11	38	119 %	21	191%
Segment net income attributable to partners	$ 119	$ 79	$ 53	$ 40	51 %	$ 26	49%
Other data:							
NGL pipelines throughput (Bbls/d) (c)	184,706	89,361	78,508	95,345	107 %	10,853	14%

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

(b) Includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 33.33% ownership in each of the Sand Hills and Southern Hills pipelines, which were contributed to us in March 2014, 33.33% ownership of the Front Range pipeline, which commenced operations in February 2014, 20% ownership of the Mont Belvieu 1 fractionator, 12.5% ownership of the Mont Belvieu Enterprise fractionator and 10% ownership of the Texas Express pipeline, which commenced operations in October 2013. Earnings for Sand Hills, Southern Hills, Front Range, Mont Belvieu 1 and Texas Express include the amortization of the net difference between the carrying amount of our investments and the underlying equity of the entities.

(c) Includes our share, based on our ownership percentage, of the throughput volumes of unconsolidated affiliates.

Year Ended December 31, 2014 vs. Year Ended December 31, 2013

Total Operating Revenues and Segment Gross Margin — Total operating revenues and segment gross margin remained relatively constant in 2014 compared to 2013.

Operating and Maintenance Expense — Operating and maintenance expense remained constant in 2014 compared to 2013.

Depreciation and Amortization Expense — Depreciation and amortization expense remained relatively constant in 2014 compared to 2013.

Other Expense — Other expense represents a write off of construction work in progress due to discontinued projects.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2014 compared to 2013 primarily as a result of the contribution of Sand Hills and Southern Hills in March 2014 and increased volumes at Front Range and Texas Express due to the amount of time in service; partially offset by lower volumes due to maintenance and unfavorable location pricing at our Mont Belvieu fractionators.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2014 compared to 2013 as a result of volume growth on certain of our pipelines, including Sand Hills and Southern Hills which were contributed to us in March 2014, Front Range which commenced operations in February 2014, Texas Express which commenced operations in October 2013 and Black Lake.

Year Ended December 31, 2013 vs. Year Ended December 31, 2012

Total Operating Revenues — Total operating revenues increased in 2013 compared to 2012 as result of increased throughput on certain of our pipelines and increased activity at our NGL storage facility.

Segment Gross Margin — Segment gross margin increased in 2013 compared to 2012 as result of increased throughput on certain of our pipelines and increased activity at our NGL storage facility.

Operating and Maintenance Expense — Operating and maintenance expense remained constant in 2013 compared to 2012.

Depreciation and Amortization Expense — Depreciation and amortization remained constant in 2013 compared to 2012.

Other Expense — Other expense represents a write off of approximately $3 million in construction work in progress in 2013 due to a discontinued project.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing 20% ownership of the Mont Belvieu 1 fractionator, 12.5% ownership of the Mont Belvieu Enterprise fractionator and 10% ownership of Texas Express, increased in 2013 compared to 2012 primarily as a result of the acquisition of the Mont Belvieu fractionators in July 2012 and the Mont Belvieu Enterprise fractionator de-bottleneck project in the third quarter of 2013. 2012 results for the Mont Belvieu 1 fractionator reflect lower margin and higher operating expenses related to a planned turnaround.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2013 compared to 2012 as a result of volume growth on our pipelines.

Results of Operations — Wholesale Propane Logistics Segment

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

	Year Ended December 31,			Variance 2014 vs. 2013		Variance 2013 vs. 2012	
	2014	2013	2012	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of propane	$ 406	$ 379	$ 397	$ 27	7 %	$ (18)	(5)%
Transportation, processing and other	3	—	—	$ 3	100 %	$ —	— %
(Losses) gains from commodity derivative activity	(3)	1	18	(4)	(400)%	(17)	(94)%
Total operating revenues	406	380	415	26	7 %	(35)	(8)%
Purchases of propane	(388)	(328)	(373)	60	18 %	(45)	(12)%
Segment gross margin (a)	18	52	42	(34)	(65)%	10	24 %
Operating and maintenance expense	(11)	(15)	(15)	(4)	(27)%	—	— %
Depreciation and amortization expense	(2)	(2)	(2)	—	— %	—	— %
Other expense	—	(4)	—	(4)	(100)%	4	100 %
Segment net income attributable to partners	$ 5	$ 31	$ 25	$ (26)	(84)%	$ 6	24 %
Other data:							
Non-cash commodity derivative mark-to-market	$ (3)	$ (1)	$ 1	$ (2)	(200)%	$ (2)	(200)%
Propane sales volume (Bbls/d)	18,335	19,553	19,111	(1,218)	(6)%	442	2 %

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

Year Ended December 31, 2014 vs. Year Ended December 31, 2013

Total Operating Revenues — Total operating revenues increased by $26 million in 2014 compared to 2013, primarily as a result of the following:

- $51 million increase attributable to higher propane prices throughout the year; and
- $3 million increase attributable to a new storage agreement with an existing customer.

This increase was partially offset by:

- $24 million decrease attributable to decreased volumes as discussed below; and
- $4 million decrease as a result of commodity derivative activity attributable to a decrease in realized cash settlement gains in 2014 compared to 2013 and an increase in unrealized commodity derivative losses in 2014 compared to 2013 due to movements in forward prices of commodities.

Purchases of Propane — Purchases of propane increased in 2014 compared to 2013 primarily due to an increase in non-cash lower of cost or market inventory adjustments to $13 million in 2014 from $2 million in 2013 and higher propane prices throughout the year, which impact both sales and purchases. These increases were partially offset by lower volumes.

Segment Gross Margin — Segment gross margin decreased in 2014 compared to 2013 primarily due to an increase in non-cash lower of cost or market inventory adjustments to $13 million in 2014 from $2 million in 2013, decreased unit margins, a decrease in volumes as discussed below, and a $4 million decrease related to commodity derivative activities as discussed above.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2014 compared to 2013 primarily as a result of a change in the structure of our marine terminal lease.

Depreciation and Amortization Expense — Depreciation and amortization expense remained constant in 2014 compared to 2013.

Other Expense — Other expense in 2013 represents a write off of approximately $4 million in construction work in progress due to a discontinued project.

Propane Sales Volume — Propane sales volumes decreased in 2014 compared to 2013 primarily due to lower inventory resulting from the conversion of certain of our assets to a storage facility, reduced shipments and decreases across certain of our assets; partially offset by new agreements and increased activity as result of a change in the structure of our marine terminal lease.

Year Ended December 31, 2013 vs. Year Ended December 31, 2012

Total Operating Revenues — Total operating revenues decreased by $35 million in 2013 compared to 2012, primarily as a result of the following:

- $25 million decrease attributable to lower propane prices; and
- $17 million decrease related to commodity derivative activity. This includes a decrease in realized cash settlement gains in 2013 compared to 2012 of $16 million, and unrealized commodity derivative losses in 2013 of $1 million due to movements in forward prices of commodities.

These decreases were partially offset by:

- $7 million increase attributable to increased volumes in part due to the export of propane from our Chesapeake terminal in the first quarter of 2013. 2012 results reflect a lack of demand due to the industry's excess inventory resulting from near record warm weather.

Purchases of Propane — Purchases of propane decreased in 2013 compared to 2012 primarily due to lower propane prices, which impacts both sales and purchases, a 2012 non-cash lower of cost or market inventory adjustment of $15 million, partially offset by increased volumes due to the export of propane from our Chesapeake terminal in the first quarter of 2013 and reduced demand in 2012 due to the industry's excess inventory resulting from near record warm weather.

Segment Gross Margin — Segment gross margin increased in 2013 compared to 2012 primarily due to increased unit margins and exporting propane from our Chesapeake terminal in the first quarter of 2013, partially offset by a $17 million decrease related to commodity derivative activities as discussed above. 2012 results reflect a non-cash lower of cost or market inventory adjustment of $15 million and reduced demand due to the industry's excess inventory resulting from near record warm weather.

Operating and Maintenance Expense — Operating and maintenance expense remained constant in 2013 compared to 2012.

Depreciation and Amortization Expense — Depreciation and amortization expense remained constant in 2013 compared to 2012.

Other Expense — Other expense represents a write off of approximately $4 million in construction work in progress in 2013 due to a discontinued project.

Propane Sales Volume — Propane sales volumes increased in 2013 compared to 2012 due to the export of propane from our Chesapeake terminal in the first quarter. 2012 results reflect a lack of demand due to the industry's excess inventory resulting from near record warm weather.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- issuance of additional common units, including issuances we may make to DCP Midstream, LLC;

- debt offerings;
- cash distributions from our unconsolidated affiliates;
- borrowings under our revolving Amended and Restated Credit Agreement;
- borrowings under term loans; and
- letters of credit.

We anticipate our more significant uses of resources to include:

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

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

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

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

In May 2014, we entered into a $1.25 billion amended and restated senior unsecured revolving credit agreement that matures on May 1, 2019, or the Amended and Restated Credit Agreement, which replaced our previous $1 billion Credit Agreement scheduled to mature on November 10, 2016. Our borrowing capacity may be limited by the Amended and Restated Credit Agreement's financial covenant requirements. Except in the case of a default, which would make the borrowings under the Amended and Restated Credit Agreement fully callable, amounts borrowed under the Amended and Restated Credit Agreement will not mature prior to the May 1, 2019 maturity date. Further, our cost of borrowing under the Amended and Restated Credit Agreement is determined by a ratings-based pricing grid. As of December 31, 2014, there was no outstanding balance on the revolving credit facility under the Amended and Restated Credit Agreement. We had unused revolver capacity of $1,249 million, net of letters of credit, under the Amended and Restated Credit Agreement. The recent lowering of our credit rating below investment grade will increase our cost of borrowings under the revolving credit facility. As of February 19, 2015, we had $94 million of credit facility borrowings outstanding and had approximately $1,155 million of unused capacity under the Amended and Restated Credit Agreement.

Our Commercial Paper Program may serve as an alternative source of funding, and does not increase our current overall borrowing capacity. Amounts available under the Commercial Paper Program may be borrowed, repaid, and re-borrowed from time to time with the maximum aggregate principal amount of notes outstanding, combined with the amount outstanding under our Amended and Restated Credit Agreement, not to exceed $1.25 billion in the aggregate. The recent lowering of our credit rating below investment grade has eliminated our ability to utilize our Commercial Paper Program.

In March 2014, we issued $325 million of 2.70% five-year Senior Notes due April 1, 2019 and $400 million of 5.60% 30-year Senior Notes due April 1, 2044. We received proceeds of $320 million, and $392 million, net of underwriters' fees, related expenses and unamortized discounts which we used to pay a portion of the consideration for the March 2014 Transactions. Interest on the notes is paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2014. The notes will mature on April 1, 2019 and April 1, 2044, unless redeemed prior to maturity.

In March 2013, we issued $500 million of 3.875% 10-year Senior Notes due March 15, 2023. We received proceeds of $490 million, net of underwriters' fees, related expenses and unamortized discounts, which we used to fund a portion of the acquisition of an additional 46.67% interest in the Eagle Ford system.

In June 2014, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of $500 million, which became effective on July 11, 2014. The shelf registration statement allows us to issue additional common units. In September 2014, we entered into an equity distribution agreement, or the 2014 equity distribution agreement, with a group of financial institutions as sales agents. The 2014 equity distribution agreement provides for the offer and sale from time to time, through our sales agents, of common units having an aggregate offering amount of up to $500 million. During the year ended December 31, 2014, we issued 2,256,066 of our common units pursuant to the 2014 equity distribution agreement and received proceeds of $119 million, net of commissions and accrued offering costs of $1 million, which were used to finance growth opportunities and for general partnership purposes. As of December 31, 2014, approximately $380 million remained available for sale pursuant to the 2014 equity distribution agreement.

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

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

In November 2013, we entered into an equity distribution agreement, or the 2013 equity distribution agreement, with a group of financial institutions as sales agents. The 2013 equity distribution agreement provided for the offer and sale from time to time, through our sales agents, of common units having an aggregate offering amount of up to $300 million. During the year ended December 31, 2014, we issued 3,769,635 common units pursuant to the 2013 equity distribution agreement and received proceeds of $206 million, which is net of commissions and offering costs of $2 million. During the year ended December 31, 2013, we issued 1,839,430 of our common units pursuant to the 2013 equity distribution agreement and received proceeds of $87 million, net of commissions and offering costs of $1 million. The proceeds were used to finance growth opportunities and for general partnership purposes. In connection with our entry into the 2014 equity distribution agreement, we terminated the 2013 equity distribution agreement in September 2014. In October 2014, we de-registered the common units that remained unsold under the 2013 equity distribution agreement at the time of its termination.

In August 2011, we entered into an equity distribution agreement with a financial institution, as sales agent. The agreement provides for the offer and sale from time to time, through our sales agent, of common units having an aggregate offering amount of up to $150 million. During the year ended December 31, 2013, we issued 1,408,547 of our common units pursuant to this equity distribution agreement and received proceeds of $67 million, net of commissions and accrued offering costs of $2 million, which were used to finance growth opportunities and for general partnership purposes. In September 2013, we de-registered the common units that remained unsold under this equity distribution agreement.

In August 2013, we issued 9,000,000 common units at $50.04 per unit. We received proceeds of $434 million, net of offering costs.

In March 2013, we issued 12,650,000 common units at $40.63 per unit. We received proceeds of $494 million, net of offering costs.

In March 2013, we issued 2,789,739 common units to DCP Midstream, LLC as partial consideration for the additional 46.67% interest in the Eagle Ford system.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through 2017 with fixed price commodity swaps. For additional information regarding our derivative activities, please read Item 7A. "Quantitative and Qualitative Disclosures about Market Risk" contained herein.

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

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

We had working capital deficits of $11 million and $220 million, as of December 31, 2014 and 2013, respectively. The change in working capital is primarily attributable to net derivative working capital of $187 million as of December 31, 2014 as compared to $51 million as of December 31, 2013, the repayment of our short-term borrowings, and the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

As of December 31, 2014, we had $25 million in cash and cash equivalents. Of this balance, $1 million was held by consolidated subsidiaries we do not wholly own. Other than the cash held by these subsidiaries, this cash balance was available for general partnership purposes.

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

	Year Ended December 31,		
	2014	2013	2012
		(Millions)	
Net cash provided by operating activities	$ 524	$ 345	$ 102
Net cash used in investing activities	$ (1,236)	$ (1,387)	$ (1,384)
Net cash provided by financing activities	$ 725	$ 1,052	$ 1,276

Year Ended December 31, 2014 vs. Year Ended December 31, 2013

Operating Activities — Net cash provided by operating activities increased $179 million in 2014 compared to 2013 primarily as a result of the following:

- $81 million increase in cash distributions from unconsolidated affiliates primarily due to a one-time distribution and increased earnings. Distributions exceeded earnings by $45 million for the year ended December 31, 2014. For additional information regarding fluctuations in our earnings from unconsolidated affiliates, please read "Results of Operations" within Item 7A. "Management's Discussion and Analysis of Financial Condition and Results of Operations";

- $66 million increase in cash attributable to higher income, after adjusting our $220 million increase in net income for non-cash items; and

- $32 million increase in cash attributable to the timing of cash receipts and disbursements related to operations, including the receipt of $68 million for our net hedge cash settlements for the year ended December 31, 2014.

Investing Activities — Net cash used in investing activities decreased $151 million in 2014 compared to 2013 primarily as a result of the following:

- $594 million decrease attributable to our acquisition of the Lucerne 1 and Lucerne 2 plants for $102 million in 2014 as compared to our acquisition of the additional 46.67% interest in the Eagle Ford system for $486 million and the O'Connor plant for $210 million in 2013;

- $91 million decrease in cash contributions to our unconsolidated affiliates primarily due to progress on the Keathley Canyon project at Discovery, which commenced construction in January 2012 and was placed into service in the first quarter of 2015, and completion of the Texas Express pipeline in the fourth quarter of 2013; partially offset by expansion projects at our Sand Hills pipeline, which was contributed to us in March 2014;

- $28 million decrease attributable to cash received from the sale of assets in 2014. The sales were primarily due to a pipeline that we sold to Front Range Pipeline LLC, as well as assets sold out of our Eagle Ford and Northern Louisiana systems; and

• $25 million decrease in capital expenditures primarily attributable to the completion of the Goliad plant in the first quarter of 2014, partially offset by construction of the Lucerne 2 plant starting in April 2014.

These decreases were partially offset by:

• $587 million increase in the acquisition of unconsolidated affiliates attributable to the contribution of 33.33% interests in each of the Sand Hills and Southern Hills pipelines for $673 million in 2014 as compared to the acquisition of Front Range for $86 million in 2013.

Financing Activities — Net cash provided by financing activities decreased $327 million in 2014 compared to 2013 primarily as a result of the following:

• $198 million in cash outflows related to our acquisition of the remaining 20% interest in the Eagle Ford system in 2014;

• $143 million increase in cash distributions to our limited and general partners primarily attributable to the issuance of 4,497,158 common units to DCP Midstream, LLC as partial consideration for the March 2014 Transactions;

• $82 million decrease in proceeds from the issuance of common units to the public. We issued approximately 20 million common units to the public in 2014 as compared to approximately 25 million units in 2013;

• $33 million decrease in net contributions from noncontrolling interests primarily due to our acquisition of the remaining 20% interest in the Eagle Ford system in 2014;

• $17 million decrease attributable to the net change in advances to our predecessor operations from DCP Midstream, LLC primarily as a result of the March 2014 Transactions; and

• $1 million decrease primarily attributable to an increase in deferred financing costs; partially offset by a decrease in distributions to DCP Midstream, LLC;

These decreases were partially offset by:

• $80 million increase in net debt borrowings; and

• $67 million increase related to a decrease in the excess purchase price over our acquired interests. In 2014, we paid $18 million over DCP Midstream, LLC's basis in the net assets acquired in the March 2014 transactions as compared $85 million over its basis in an additional 46.67% interest in the Eagle Ford system in 2013.

The weighted-average indebtedness outstanding under the Commercial Paper Program was $259 million, $26 million, $4 million and $10 million for the first, second, third and fourth quarters of 2014. As of December 31, 2014, we had no commercial paper outstanding.

Years Ended December 31, 2013 and 2012

Net Cash Provided by Operating Activities — We received $54 million for our net hedge cash settlements for the year ended December 31, 2013, of which less than $1 million was associated with rebalancing our portfolio, and approximately $49 million for the year ended December 31, 2012.

We received cash distributions from unconsolidated affiliates of $39 million and $24 million during the years ended December 31, 2013 and 2012, respectively. Distributions exceeded earnings by $6 million for the year ended December 31, 2013.

Net Cash Used in Investing Activities — Net cash used in investing activities during the year ended December 31, 2013 was comprised of: (1) acquisition expenditures of $782 million related to our acquisition of the additional 46.67% interest in the Eagle Ford system for $486 million, the O'Connor plant for $210 million and Front Range for $86 million; (2) capital expenditures of $363 million (our portion of which was $325 million and the noncontrolling interests portion was $38 million) consisting of construction of the Goliad plant, construction and expansion of the O'Connor plant, expansion and upgrades to our Southeast Texas complex, expansion of the Marysville NGL storage facility, expansion of our Chesapeake facility and other projects; and (3) investments in unconsolidated affiliates of $242 million consisting of $133 million to Discovery, $55 million to Texas Express, $48 million to Front Range and $6 million to Mont Belvieu Enterprise Fractionator.

Net cash used in investing activities during 2012 was comprised of: (1) acquisition expenditures of $745 million, of which $282 million is related to our acquisition of the initial 33.33% interest in the Eagle Ford system, $193 million is related to our acquisition of the remaining 66.67% interest in Southeast Texas, $120 million related to our acquisition of the remaining 49.9% interest in East Texas, $63 million related to our acquisition of Crossroads, $57 million related to the acquisition of the Goliad plant by the Eagle Ford system, and $30 million related to our acquisition of the Mont Belvieu fractionators; (2) capital expenditures of $484 million (of which our portion was $411 million and the noncontrolling interest holders' portion and the reimbursable projects portion was $73 million); and (3) investments in unconsolidated affiliates of $158 million; partially offset by (4) proceeds from sales of assets of $2 million; and (5) a return of investment from unconsolidated affiliate of $1 million.

Net Cash Provided by Financing Activities — Net cash provided by financing activities during 2013 was comprised of: (1) proceeds from long-term debt of $1,957 million, offset by payments of $1,988 million, for net repayment of long-term debt of $31 million; (2) proceeds from the issuance of commercial paper of $335 million; (3) proceeds from the issuance of common units, net of offering costs, of $1,083 million; (4) contributions from noncontrolling interests of $46 million; (5) net change in advances to predecessor from DCP Midstream, LLC of $11 million; and (6) contributions from DCP Midstream, LLC of $1 million; partially offset by (7) distributions to our limited partners and general partner of $277 million; (8) excess purchase price over acquired interests and commodity hedges of $85 million; (9) distributions to noncontrolling interests of $24 million; (10) payment of deferred financing costs of $4 million; and (11) distributions to DCP Midstream, LLC of $3 million relating to capital expenditures for reimbursable projects.

During the year ended December 31, 2013, total outstanding indebtedness under our $1 billion Credit Agreement, which includes borrowings under our revolving credit facility and letters of credit issued under the Credit Agreement, was not less than $1 million and did not exceed $607 million. The weighted-average indebtedness outstanding under the revolving credit facility was $429 million, $201 million, $265 million and $130 million for the first, second, third and fourth quarters of 2013, respectively.

The weighted-average indebtedness outstanding under the Commercial Paper Program was $273 million for the fourth quarter of 2013.

As of December 31, 2013, we had unused capacity under the revolving credit facility of $664 million, all of which was available for general working capital purposes.

During the year ended December 31, 2013, we had the following movements on our revolving credit facility:

- $494 million repayment financed by the issuance of 12,650,000 common units in March 2013;
- $434 million repayment financed by the issuance of 9,000,000 common units in August 2013; and
- $335 million repayment financed by borrowings under our Commercial Paper Program; partially offset by
- $209 million borrowings to fund the acquisition of the O'Connor plant;
- $363 million net borrowings for general working capital purposes;
- $86 million borrowings to fund the acquisition of the Front Range pipeline; and
- $80 million borrowings primarily to reimburse DCP Midstream, LLC for its proportionate share of the capital spent to date, at closing, by the Eagle Ford system for the construction of the Goliad plant and for preformation capital expenditures.

Net cash provided by financing activities during 2012 was comprised of: (1) proceeds from long-term debt of $2,665 million, offset by payments of $1,792 million, for net borrowing of long-term debt of $873 million; (2) proceeds from the issuance of common units net of offering costs of $455 million; (3) net change in advances to predecessor from DCP Midstream, LLC of $336 million; (4) contributions from noncontrolling interest of $25 million; (5) contributions from DCP Midstream, LLC of $10 million; partially offset by (6) distributions to our limited partners and general partner of $181 million; (7) excess purchase price over acquired interests of $225 million (8) distributions to noncontrolling interests of $9 million; and (9) payment of deferred financing costs of $8 million.

During 2012, total outstanding indebtedness under our $1 billion Credit Agreement, which includes borrowings under our revolving credit facility and letters of credit issued under the Credit Agreement, was not less than $268 million and did not exceed $576 million. The weighted-average indebtedness outstanding under the Credit Agreement was $496 million, $369 million, $321 million and $455 million for the first, second, third and fourth quarters of 2012, respectively.

We had unused capacity, which is available for commitments under the Credit Agreement, of $732 million, $649 million, $699 million and $474 million at the end of the first, second, third and fourth quarters of 2012, respectively.

During 2012, we had the following movements on our revolving credit facility:

- $63 million borrowing to fund the acquisition of the Crossroads system; and
- $199 million net borrowings for general working capital purposes; partially offset by
- $234 million repayment with proceeds from the issuance of 5,148,500 common units in March 2012.

We expect to continue to use cash provided by operating activities for the payment of distributions to our unitholders and general partner. See Note 13. "Partnership Equity and Distributions" in the Notes to Consolidated Financial Statements in Item 8. “Financial Statements.”

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

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

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

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

	Year Ended December 31, 2014			Year Ended December 31, 2013		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)					
Our portion	$ 38	$ 299	$ 337	$ 23	$ 302	$ 325
Noncontrolling interest portion and reimbursable projects (a)	(4)	5	1	2	36	38
Total	$ 34	$ 304	$ 338	$ 25	$ 338	$ 363

	Year Ended December 31, 2012		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)		
Our portion	$ 23	$ 388	$ 411
Noncontrolling interest portion and reimbursable projects (a)	8	65	73
Total	$ 31	$ 453	$ 484

(a) Represents the noncontrolling interest and reimbursable portion of our capital expenditures. In conjunction with our acquisitions of our East Texas and Southeast Texas systems, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse us for certain expenditures on capital projects. These reimbursements are for certain capital projects which commenced within three years from the respective acquisition dates. We have also entered into agreements with third parties whereby we will be reimbursed for certain expenditures. Depending on the timing of these payments, we may be reimbursed prior to incurring the capital expenditure.

In addition, we invested cash in unconsolidated affiliates of $151 million, $242 million and $158 million, net of returns, during the years ended December 31, 2014, 2013 and 2012, respectively, to fund our share of capital expansion projects.

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

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

Cash Distributions to Unitholders — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders and general partner of $420 million, $277 million and $181 million during the years ended December 31, 2014, 2013 and 2012, respectively. We intend to continue making quarterly distribution payments to our unitholders and general partner to the extent we have sufficient cash from operations after the establishment of reserves.

Amended and Restated Credit Agreement — On May 1, 2014, we entered into a $1.25 billion amended and restated senior unsecured revolving credit agreement that matures on May 1, 2019, or the Amended and Restated Credit Agreement, which replaced our previous $1 billion Credit Agreement scheduled to mature on November 10, 2016.

As of December 31, 2014, there was no outstanding balance on the revolving credit facility under the Amended and Restated Credit Agreement. We had unused revolver capacity of $1,249 million, net of letters of credit.

Our obligations under the revolving credit facility are unsecured. The unused portion of the revolving credit facility may be used for letters of credit up to a maximum of $500 million of outstanding letters of credit. At December 31, 2014 and December 31, 2013, we had $1 million outstanding letters of credit issued under the Amended and Restated Credit Agreement.

Amounts undrawn under the revolving credit facility are available to repay amounts borrowed under our Commercial Paper Program, if necessary.

We may prepay all loans at any time without penalty, subject to the reimbursement of lender breakage costs in the case of prepayment of London Interbank Offered Rate, or LIBOR, borrowings. As of December 31, 2014, indebtedness under the Amended and Restated Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.275% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.275% based on our current credit rating. The revolving credit facility incurs an annual facility fee of 0.225% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $1.25 billion revolving credit facility.

The Amended and Restated Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended and Restated Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.5 to 1.0. Further, our cost of borrowing under the Amended and Restated Credit Agreement is determined by a ratings-based pricing grid. A downgrade in our credit ratings will increase our cost of borrowings under the revolving credit facility.

Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, interest rates and fees under the DCP Partners Amended and Restated Credit Agreement have increased.

Commercial Paper Program – We have a Commercial Paper Program under which we may issue unsecured commercial paper notes, or the Notes. The Commercial Paper Program may serve as an alternative source of funding and does not increase our current overall borrowing capacity. Amounts available under the Commercial Paper Program may be borrowed, repaid, and re-borrowed from time to time with the maximum aggregate principal amount of Notes outstanding, combined with the amount outstanding under our Amended and Restated Credit Agreement, not to exceed $1.25 billion in the aggregate. Amounts undrawn under our Amended and Restated Credit Agreement are available to repay the Notes, if necessary. The maturities of the Notes will vary, but may not exceed 397 days from the date of issue. The Notes will be sold under customary terms in the commercial paper market and may be issued at a discount from par, or, alternatively, may be sold at par and bear varying interest rates on a fixed or floating basis. The proceeds of the issuances of the Notes are expected to be used for capital expenditures and other general partnership purposes. As of December 31, 2014, we had no commercial paper outstanding.

Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, we longer have access to the Commercial Paper Program. Our available liquidity under the Commercial Paper Program will be replaced with borrowings under the DCP Partners Amended and Restated Credit Agreement.

Debt Securities – In March 2014, we issued $325 million of 2.70% five-year Senior Notes due April 1, 2019 and $400 million of 5.60% 30-year Senior Notes due April 1, 2044. We received proceeds of $320 million and $392 million, net of underwriters' fees, related expenses and unamortized discounts which we used to pay a portion of the consideration for the March 2014 Transactions. Interest on the notes is paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2014. The notes will mature on April 1, 2019 and April 1, 2044, respectively, unless redeemed prior to maturity.

In March 2013, we issued $500 million of 3.875% 10-year Senior Notes due March 15, 2023. We received proceeds of $490 million, net of underwriters' fees, related expenses and unamortized discounts, which we used to fund the cash portion of the purchase price for the acquisition of an additional 46.67% interest in the Eagle Ford system. Interest on the notes is paid semi-annually on March 15 and September 15 of each year, commencing September 15, 2013. The notes will mature on March 15, 2023, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

The series of notes are senior unsecured obligations, ranking equally in right of payment with our existing unsecured indebtedness, including indebtedness under our Amended and Restated Credit Agreement. We are not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at our option.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of December 31, 2014, is as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
			(Millions)		
Debt (a)	$ 3,367	$ 340	$ 661	$ 456	$ 1,910
Operating lease obligations (b)	81	15	23	17	26
Purchase obligations (c)	146	138	5	—	3
Other long-term liabilities (d)	34	—	1	—	33
Total	$ 3,628	$ 493	$ 690	$ 473	$ 1,972

(a) Includes interest payments on debt securities that have been issued. These interest payments are $90 million, $161 million, $131 million, and $660 million for less than one year, one to three years, three to five years, and thereafter, respectively.

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

(c) Our purchase obligations are contractual obligations and include purchase orders and non-cancelable construction agreements for capital expenditures, various non-cancelable commitments to purchase physical quantities of propane supply for our Wholesale Propane Logistics business and other items. For contracts where the price paid is based on an index or other market-based rates, the amount is based on the forward market prices or current market rates as of December 31, 2014. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in the consolidated balance sheet, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities of the underlying commodity. In addition, many of our gas purchase contracts include short and long-term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(d) Other long-term liabilities include $27 million of asset retirement obligations of which an insignificant amount may be settled within the next five years, $4 million of gas purchase liability, $2 million of right of way liability and $1 million of environmental reserves recognized in the December 31, 2014 consolidated balance sheet. In addition, $13 million of deferred state income taxes were excluded from the table above as the amount and timing of any payments are not subject to reasonable estimation.

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

Critical Accounting Policies and Estimates

Our financial statements reflect the selection and application of accounting policies that require management to make estimates and assumptions. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations. These accounting policies are described further in Note 2 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Impairment of Goodwill		
We evaluate goodwill for impairment annually in the third quarter, 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.	We determine fair value using widely accepted valuation techniques, namely discounted cash flow and market multiple analyses. These techniques are also used when assigning the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. 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.	We primarily use a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If our assumptions are not appropriate, or future events indicate that our goodwill is impaired, our net income would be impacted by the amount by which the carrying value exceeds the fair value of the reporting unit, to the extent of the balance of goodwill. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill impairment for reporting units due to the potential impact on our operations and cash flows. We have not recorded any impairment charges on goodwill during the year ended December 31, 2014.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Impairment of Long-Lived Assets		
We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections expected to be realized over the remaining useful life of the primary asset. The carrying amount is not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value.	Our impairment analyses require management to apply judgment in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. If the carrying value is not recoverable, we assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models.	Using the impairment review methodology described herein, we have not recorded any impairment charges on long-lived assets during the year ended December 31, 2014. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.
Impairment of Investments in Unconsolidated Affiliates		
We evaluate our investments in unconsolidated affiliates 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 loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred.	Our impairment analyses require management to apply judgment in estimating future cash flows and asset fair values, including forecasting useful lives of the assets, assessing the probability of differing estimated outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. When there is evidence of loss in value, we assess the fair value of our unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models.	Using the impairment review methodology described herein, we have not recorded any impairment charges on investments in unconsolidated affiliates during the year ended December 31, 2014. If the estimated fair value of our unconsolidated affiliates is less than the carrying value, we would recognize an impairment loss for the excess of the carrying value over the estimated fair value. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Accounting for Risk Management Activities and Financial Instruments		
Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on derivative instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments at fair value until the contractual settlement period impacts earnings. Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions.	When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical information and the expected relationship with quoted market prices.	If our estimates of fair value are inaccurate, we may be exposed to losses or gains that could be material. A 10% difference in our estimated fair value of derivatives at December 31, 2014 would have affected net income by approximately $23 million based on our net derivative position for the year ended December 31, 2014.
Accounting for Asset Retirement Obligations		
Asset retirement obligations associated with tangible long-lived assets 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 accretes due to the passage of time based on the time value of money until the obligation is settled.	Estimating the fair value of asset retirement obligations requires management to apply judgment to evaluate the necessary retirement activities, estimate the costs to perform those activities, including the timing and duration of potential future retirement activities, and estimate the risk free interest rate. When making these assumptions, we consider a number of factors, including historical retirement costs, the location and complexity of the asset and general economic conditions.	If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may experience material changes in our asset retirement obligations. Establishing an asset retirement obligation has no initial impact on net income. A 10% change in depreciation and accretion expense associated with our asset retirement obligations during the year ended December 31, 2014 would have less than a $1 million impact on our net income.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

Market risk is the risk of loss arising from adverse changes in market prices and rates. We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as forward contracts, swaps and futures to mitigate a portion of the effects of identified risks. In general, we attempt to mitigate a portion of the risks related to the variability of future earnings and cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements.

Risk Management Policy

We have established a comprehensive risk management policy, or Risk Management Policy, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. Our Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of counterparty credit risk and commodity price risk, including monitoring exposure limits.

See Note 12, Risk Management and Hedging Activities, of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" for further discussion of the accounting for derivative contracts.

Credit Risk

Our principal customers in the Natural Gas Services segment are large, natural gas marketers and industrial end-users. In the NGL Logistics Segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Our principal customers in the Wholesale Propane Logistics segment are primarily propane distributors. Substantially all of our natural gas, propane and NGL sales are made at market-based prices. This concentration of credit risk may affect our overall credit risk, as these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC's corporate credit policy. DCP Midstream, LLC's corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC's credit policy. Our standard agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Interest Rate Risk

Interest rates on future credit agreement draws and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances. We may mitigate a portion of our future interest rate risk with interest rate swaps that reduce our exposure to market rate fluctuations by converting variable interest rates on our debt to fixed interest rates and locking in rates on our anticipated future fixed-rate debt, respectively.

We had interest rate swap agreements through June 2014 with notional values totaling $150 million, which are accounted for under the mark-to-market method of accounting and reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we paid fixed-rates ranging from 2.94% to 2.99%, and received interest payments based on the one-month LIBOR. Prior to August of 2013, these interest rate swaps were designated as cash flow hedges whereby the effective portions of changes in fair value were recognized in AOCI in the consolidated balance sheets.

At December 31, 2014, the effective weighted-average interest rate on our outstanding debt was 3.83%.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering services, we receive fees or commodities from producers to bring the natural gas from the wellhead to the processing plant. For processing and storage services, we either receive fees or commodities as payment for these services, depending on the types of contracts. We employ established policies and procedures to manage our risks associated with these market fluctuations using various commodity derivatives, including forward contracts, swaps, costless collars and futures.

Commodity Cash Flow Protection Activities - We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various fixed price swaps and costless collar arrangements to mitigate a portion of the effect pricing fluctuations may have on the value of our assets and operations. Depending on our risk management objectives, we may periodically settle a portion of these instruments prior to their maturity.

We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices, however there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. During 2014, the relationship of NGLs to crude oil has been lower than historical relationships, however a significant amount of our NGL hedges from 2015 through 2016 are direct product hedges. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps.

Commodity prices have declined substantially compared to historical periods and experienced significant volatility during the latter part of 2014, as illustrated in Item 1A. Risk Factors - "Current economic conditions may adversely affect producers' drilling activity and transportation spending levels, which may in turn negatively impact our volumes and results of operations and our ability to make distributions to our unitholders." If commodity prices remain weak for a sustained period, our natural gas throughput and NGL volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Furthermore, a sustained decline in commodity prices could result in a decrease in exploration and development activities in the fields served by our gas gathering and residue gas and NGL pipeline transportation systems, and our natural gas treating and processing plants, which could lead to reduced utilization of these assets.

The derivative financial instruments we have entered into are typically referred to as "swap" contracts. The swap contracts entitle us to receive payment at settlement from the counterparty to the contract to the extent that the reference price is below the swap price stated in the contract, and we are required to make payment at settlement to the counterparty to the extent that the reference price is higher than the swap price stated in the contract.

We use the mark-to-market method of accounting for all commodity cash flow protection activities, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on derivative activity.

The following tables set forth additional information about our fixed price swaps used to mitigate a portion of our natural gas and NGL price risk associated with our percent-of-proceeds arrangements and our condensate price risk associated with our gathering operations. As noted in the table below, the majority of our positions extend through 2015 with a limited amount settling in 2016 and 2107. Our positions as of February 19, 2015 are as follows:

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions		Reference Price	Price Range
January 2015 — December 2015	Natural Gas	(24,738) MMBtu/d	(f)	IFERC Monthly Index Price for Houston Ship Channel (c)	$4.50/MMBtu
January 2016 — March 2016	Natural Gas	(16,163) MMBtu/d	(f)	IFERC Monthly Index Price for Houston Ship Channel (c)	$4.50/MMBtu
January 2015 — December 2015	Natural Gas	(8,677) MMBtu/d	(f)	IFERC Monthly Index Price for Henry Hub (d)	$4.50/MMBtu
January 2016 — March 2016	Natural Gas	(4,041) MMBtu/d	(f)	IFERC Monthly Index Price for Henry Hub (d)	$4.50/MMBtu
January 2016 — December 2016	Natural Gas	(5,000) MMBtu/d	(f)	NYMEX Final Settlement Price (e)	$4.18/MMBtu
January 2017 — December 2017	Natural Gas	(17,500) MMBtu/d	(f)	NYMEX Final Settlement Price (e)	$4.17 - $4.27/MMBtu
January 2015 — March 2015	NGLs	(16,893) Bbls/d	(f)	Mt.Belvieu Non-TET (b)	$0.64 - $2.60/Gal
April 2015 — December 2015	NGLs	(15,168) Bbls/d	(f)	Mt.Belvieu Non-TET (b)	$0.64 - $1.89/Gal
January 2016 — March 2016	NGLs	(8,937) Bbls/d	(f)	Mt.Belvieu Non-TET (b)	$0.64 - $1.89/Gal
January 2015 — December 2015	Crude Oil	(1,800) Bbls/d	(g)	Asian-pricing of NYMEX crude oil futures (a)	$87.60 - $100.04/Bbl
January 2015 — December 2015	Crude Oil	(243) Bbls/d	(f)	Asian-pricing of NYMEX crude oil futures (a)	$95.00/Bbl
January 2016 — December 2016	Crude Oil	(1,500) Bbls/d	(g)	Asian-pricing of NYMEX crude oil futures (a)	$85.15 - $101.30/Bbl
January 2016 — March 2016	Crude Oil	(142) Bbls/d	(f)	Asian-pricing of NYMEX crude oil futures (a)	$95.00/Bbl
January 2015 — December 2015	Natural Gas	7,500 MMBtu/d	(g)	NYMEX Final Settlement Price (e)	$4.15 - $4.22/MMBtu

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

(g) Represents a position in which the counterparty is a third party.

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

Commodity Sensitivities Excluding Non-Cash Mark-To Market

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

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

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

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

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income Attributable to Partners)
			(Millions)
Natural gas prices	$ 0.10	MMBtu	$ 2
Crude oil prices	$ 1.00	Barrel	$ 1
NGL prices	$ 0.01	Gallon	$ 3

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

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

Based on historical trends, we generally expect NGL prices to directionally follow changes in crude oil prices over the long-term. However, the pricing relationship between NGLs and crude oil may vary, as we believe crude oil prices will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy, whereas NGL prices are more correlated to supply and U.S. petrochemical demand. However, the level of NGL exports has increased in recent years. We believe that future natural gas prices will be influenced by North American supply deliverability, the severity of winter and summer weather, the level of North American production and drilling activity of exploration and production companies and the balance of trade between imports and exports of liquid natural gas and NGLs. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would reduce natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall relative to demand levels.

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

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

The following tables set forth additional information about our derivative instruments used to mitigate a portion of our natural gas price risk associated with our Southeast Texas storage operations, as of December 31, 2014:

Inventory

Period ended	Commodity	Notional Volume - Long Positions	Fair Value (millions)	Weighted Average Price
December 31, 2014	Natural Gas	11,080,668 MMBtu	$ 34	$3.04/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Fair Value (millions)	Price Range
January 2015-January 2016	Natural Gas	(49,337,500) MMBtu	$ 47	$3.52 - $4.25/MMBtu
January 2015-December 2015	Natural Gas	37,397,500 MMBtu	$ (36)	$3.04 - $4.62/MMBtu

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. Occasionally, we may enter into fixed price sales agreements in the event that a propane distributor desires to purchase propane from us on a fixed price basis. We manage this risk with both physical and financial transactions, sometimes using non-trading derivative instruments, which generally allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

We manage our commodity derivative activities in accordance with our Risk Management Policy which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

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

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

The fair value of our interest rate swaps and commodity non-trading derivatives is expected to be realized in future periods, as detailed in the following table. The amount of cash ultimately realized for these contracts will differ from the amounts shown in the following table due to factors such as market volatility, counterparty default and other unforeseen events that could impact the amount and/or realization of these values.

	Fair Value of Contracts as of December 31, 2014		
Sources of Fair Value	**Total**	**Maturity in 2015**	**Maturity in 2016-2017**
		(Millions)	
Prices supported by quoted market prices and other external sources	$ 70	$ 49	$ 21
Prices based on models or other valuation techniques	156	138	18
Total	$ 226	$ 187	$ 39

The "prices supported by quoted market prices and other external sources" category includes our interest rate swaps, our New York Mercantile Exchange, or NYMEX, positions in natural gas, NGLs and crude oil. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes "strip" transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate.

The "prices based on models and other valuation methods" category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point.

Item 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS

DCP MIDSTREAM PARTNERS, LP CONSOLIDATED FINANCIAL STATEMENTS:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
DCP Midstream GP, LLC
Denver, Colorado

We have audited the accompanying consolidated balance sheets of DCP Midstream Partners, LP and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 25, 2015

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 25	$ 12
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $1 million	106	130
Affiliates	164	212
Inventories	63	67
Unrealized gains on derivative instruments	230	79
Other	2	3
Total current assets	590	503
Property, plant and equipment, net	3,347	3,046
Goodwill	154	154
Intangible assets, net	120	129
Investments in unconsolidated affiliates	1,459	627
Unrealized gains on derivative instruments	39	87
Other long-term assets	30	21
Total assets	$ 5,739	$ 4,567
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 196	$ 232
Affiliates	27	43
Short-term borrowings	—	335
Current maturities of long-term debt	250	—
Unrealized losses on derivative instruments	43	28
Other	85	85
Total current liabilities	601	723
Long-term debt	2,061	1,590
Unrealized losses on derivative instruments	—	1
Other long-term liabilities	51	40
Total liabilities	2,713	2,354
Commitments and contingent liabilities		
Equity:		
Predecessor equity	—	40
Limited partners (113,949,868 and 89,045,139 common units issued and outstanding, respectively)	2,984	1,948
General partner	18	8
Accumulated other comprehensive loss	(9)	(11)
Total partners' equity	2,993	1,985
Noncontrolling interests	33	228
Total equity	3,026	2,213
Total liabilities and equity	$ 5,739	$ 4,567

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2014	2013	2012
	(Millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 963	$ 932	$ 820
Sales of natural gas, propane, NGLs and condensate to affiliates	2,180	1,831	1,700
Transportation, processing and other	239	211	179
Transportation, processing and other to affiliates	106	60	55
Gains (losses) from commodity derivative activity, net	36	(5)	17
Gains from commodity derivative activity, net — affiliates	118	22	53
Total operating revenues	3,642	3,051	2,824
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	2,524	2,159	1,807
Purchases of natural gas, propane and NGLs from affiliates	271	267	408
Operating and maintenance expense	216	215	197
Depreciation and amortization expense	110	95	91
General and administrative expense	17	17	17
General and administrative expense — affiliates	47	46	58
Other expense	3	8	—
Total operating costs and expenses	3,188	2,807	2,578
Operating income	454	244	246
Interest expense	(86)	(52)	(42)
Earnings from unconsolidated affiliates	75	33	26
Income before income taxes	443	225	230
Income tax expense	(6)	(8)	(1)
Net income	437	217	229
Net income attributable to noncontrolling interests	(14)	(17)	(13)
Net income attributable to partners	423	200	216
Net income attributable to predecessor operations	(6)	(25)	(51)
General partner's interest in net income	(114)	(70)	(41)
Net income allocable to limited partners	$ 303	$ 105	$ 124
Net income per limited partner unit — basic and diluted	$ 2.84	$ 1.34	$ 2.28
Weighted-average limited partner units outstanding — basic and diluted	106.6	78.4	54.5

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2014	2013	2012
		(Millions)	
Net income	$ 437	$ 217	$ 229
Other comprehensive income:			
Reclassification of cash flow hedge losses into earnings	2	4	10
Net unrealized losses on cash flow hedges - predecessor operations	—	—	(1)
Total other comprehensive income	2	4	9
Total comprehensive income	439	221	238
Total comprehensive income attributable to noncontrolling interests	(14)	(17)	(13)
Total comprehensive income attributable to partners	$ 425	$ 204	$ 225

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Partners' Equity					
	Predecessor Equity	Limited Partners	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
			(Millions)			
Balance, January 1, 2014	$ 40	$ 1,948	$ 8	$ (11)	$ 228	$ 2,213
Net income	6	303	114	—	14	437
Other comprehensive income	—	—	—	2	—	2
Net change in parent advances	(6)	—	—	—	—	(6)
Acquisition of Lucerne 1 plant	(40)	—	—	—	—	(40)
Issuance of 4,497,158 units to DCP Midstream, LLC and affiliates	—	225	—	—	—	225
Excess purchase price over carrying value of interests acquired in March 2014 Transactions	—	(178)	—	—	—	(178)
Issuance of 20,407,571 common units to the public	—	1,002	—	—	—	1,002
Distributions to limited partners and general partner	—	(316)	(104)	—	—	(420)
Distributions to noncontrolling interests	—	—	—	—	(14)	(14)
Contributions from noncontrolling interests	—	—	—	—	3	3
Purchase of additional interest in a subsidiary	—	—	—	—	(198)	(198)
Balance, December 31, 2014	$ —	$ 2,984	$ 18	$ (9)	$ 33	$ 3,026

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Partners' Equity					
	Predecessor Equity	Limited Partners	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(Millions)					
Balance, January 1, 2013	$ 399	$ 1,063	$ —	$ (15)	$ 189	$ 1,636
Net income	25	105	70	—	17	217
Other comprehensive income	—	—	—	4	—	4
Net change in parent advances	11	—	—	—	—	11
Acquisition of additional 46.67% interest in the Eagle Ford system	(395)	—	—	—	—	(395)
Issuance of units for the Eagle Ford system	—	125	—	—	—	125
Excess purchase price over carrying value of acquired investment of 33.33% interest in the Eagle Ford system and NGL hedge	—	(7)	—	—	—	(7)
Excess purchase price over carrying value of acquired investment of 46.67% interest in the Eagle Ford system and commodity hedge	—	(203)	—	—	—	(203)
Issuance of 24,897,977 common units	—	1,082	—	—	—	1,082
Distributions to limited partners and general partner	—	(215)	(62)	—	—	(277)
Distributions to noncontrolling interests	—	—	—	—	(24)	(24)
Contributions from noncontrolling interests	—	—	—	—	46	46
Contributions from DCP Midstream, LLC	—	1	—	—	—	1
Distributions to DCP Midstream, LLC	—	(3)	—	—	—	(3)
Balance, December 31, 2013	$ 40	$ 1,948	$ 8	$ (11)	$ 228	$ 2,213

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Partners' Equity					
	Predecessor Equity	Limited Partners	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
			(Millions)			
Balance, January 1, 2012	$ 671	$ 654	$ (5)	$ (21)	$ 306	$ 1,605
Net income	51	124	41	—	13	229
Other comprehensive (loss) income	(1)	—	—	10	—	9
Net change in advances to predecessor from DCP Midstream, LLC	181	—	—	—	40	221
Acquisition of 33.33% interest in the Eagle Ford system	(232)	—	—	—	—	(232)
Acquisition of additional 66.67% interest in Southeast Texas and NGL Hedge	(248)	40	—	—	—	(208)
Acquisition of additional 49.9% interest in East Texas	—	—	—	—	(176)	(176)
Issuance of units for Southeast Texas	—	48	—	—	—	48
Issuance of units for East Texas	—	33	—	—	—	33
Issuance of units for Mont Belvieu fractionators	—	60	—	—	—	60
Issuance of units for 33.33% interest in the Eagle Ford system	—	88	—	—	—	88
Deficit purchase price under carrying value of acquired net assets for Southeast Texas and East Texas	—	36	—	(4)	—	32
Excess purchase price over carrying value of acquired investments in Mont Belvieu fractionators	—	(175)	—	—	—	(175)
Excess purchase price over carrying value of acquired investment of 33.33% interest in the Eagle Ford system and NGL Hedge	—	(156)	—	—	—	(156)
Excess purchase price over carrying value of acquired net assets by the Eagle Ford system for Goliad and NGL Hedge	(23)	(9)	—	—	(10)	(42)
Issuance of 11,285,956 common units	—	455	—	—	—	455
Distributions to limited partners and general partner	—	(145)	(36)	—	—	(181)
Distributions to noncontrolling interests	—	—	—	—	(9)	(9)
Contributions from noncontrolling interests	—	—	—	—	25	25
Contributions from DCP Midstream, LLC	—	10	—	—	—	10
Balance, December 31, 2012	$ 399	$ 1,063	$ —	$ (15)	$ 189	$ 1,636

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2014	2013	2012
		(Millions)	
OPERATING ACTIVITIES:			
Net income	$ 437	$ 217	$ 229
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	110	95	91
Earnings from unconsolidated affiliates	(75)	(33)	(26)
Distributions from unconsolidated affiliates	120	39	24
Net unrealized (gains) losses on derivative instruments	(86)	36	(21)
Other, net	14	19	3
Change in operating assets and liabilities, which provided (used) cash, net of effects of acquisitions:			
Accounts receivable	68	(89)	(11)
Inventories	4	9	14
Accounts payable	(67)	51	(194)
Accrued interest	8	5	5
Other current assets and liabilities	(5)	(2)	(4)
Other long-term assets and liabilities	(4)	(2)	(8)
Net cash provided by operating activities	524	345	102
INVESTING ACTIVITIES:			
Capital expenditures	(338)	(363)	(484)
Acquisitions, net of cash acquired	(102)	(696)	(433)
Acquisition of unconsolidated affiliates	(673)	(86)	(312)
Investments in unconsolidated affiliates	(151)	(242)	(158)
Return of investment from unconsolidated affiliate	—	—	1
Proceeds from sales of assets	28	—	2
Net cash used in investing activities	(1,236)	(1,387)	(1,384)
FINANCING ACTIVITIES:			
Proceeds from long-term debt	719	1,957	2,665
Payments of long-term debt	—	(1,988)	(1,792)
(Payments) proceeds of commercial paper, net	(335)	335	—
Payments of deferred financing costs	(7)	(4)	(8)
Excess purchase price over acquired interests and commodity hedges	(18)	(85)	(225)
Proceeds from issuance of common units, net of offering costs	1,001	1,083	455
Net change in advances to predecessor from DCP Midstream, LLC	(6)	11	336
Distributions to limited partners and general partner	(420)	(277)	(181)
Distributions to noncontrolling interests	(14)	(24)	(9)
Purchase of additional interest in a subsidiary	(198)	—	—
Contributions from noncontrolling interests	3	46	25
Distributions to DCP Midstream, LLC	—	(3)	—
Contributions from DCP Midstream, LLC	—	1	10
Net cash provided by financing activities	725	1,052	1,276
Net change in cash and cash equivalents	13	10	(6)
Cash and cash equivalents, beginning of period	12	2	8
Cash and cash equivalents, end of period	$ 25	$ 12	$ 2

See accompanying notes to consolidated financial statements.

1. Description of Business and Basis of Presentation

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

We are a Delaware limited partnership that was formed in August 2005. Our partnership includes our Natural Gas Services, NGL Logistics and Wholesale Propane Logistics segments. For additional information regarding these segments, see Note 18 - Business Segments.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, and is 100% owned by DCP Midstream, LLC. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Phillips 66 and 50% by Spectra Energy Corp and its affiliates, or Spectra Energy. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC's employees provide administrative support to us and operate most of our assets. DCP Midstream, LLC owns approximately 21.5% of us, including its limited partner and general partner interests.

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

Our predecessor results consist of the Lucerne 1 plant, which we acquired from DCP Midstream, LLC in March 2014, an 80% interest in the Eagle Ford system, of which we acquired 46.67% and 33.33% from DCP Midstream, LLC in March 2013 and November 2012, respectively, and a 66.67% interest in the Southeast Texas system, which we acquired from DCP Midstream, LLC in March 2012. Prior to our acquisition of the additional 46.67% interest in the Eagle Ford system in March 2013, we accounted for our initial 33.33% interest as an unconsolidated affiliate using the equity method. Subsequent to the March 2013 transaction, but prior to the acquisition of the remaining 20% interest in March 2014, we owned 80% of the Eagle Ford system which we accounted for as a consolidated subsidiary. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information, similar to the pooling method. Accordingly, our consolidated financial statements include the historical results of our Lucerne 1 plant, our initial 80% interest in the Eagle Ford system and the remaining 66.67% interest in the Southeast Texas system for all periods presented. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC's basis in the net assets contributed. The amount of the purchase price in excess or in deficit of DCP Midstream, LLC's basis in the net assets is recognized as a reduction or an addition to limited partners' equity. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity. In addition, the results of operations for acquisitions accounted for as business combinations have been included in the consolidated financial statements since their respective acquisition dates.

2. Summary of Significant Accounting Policies

Use of Estimates - Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could differ from those estimates.

Cash and Cash Equivalents - We consider investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less and temporary investments of cash in short-term money market securities to be cash equivalents.

Allowance for Doubtful Accounts - Management estimates the amount of required allowances for the potential non-collectability of accounts receivable generally based upon the number of days past due, past collection experience and consideration of other relevant factors. However, past experience may not be indicative of future collections and therefore additional charges could be incurred in the future to reflect differences between estimated and actual collections.

Inventories - Inventories, which consist primarily of NGLs and natural gas, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Accounting for Risk Management Activities and Financial Instruments - Non-trading energy commodity derivatives are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales. The remaining non-trading derivatives, which are related to asset-based activities for which the normal purchase or normal sale exception is not elected, are recorded at fair value in the consolidated balance sheets as unrealized gains or unrealized losses in derivative instruments, with changes in the fair value recognized in the consolidated statements of operations. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Cash Flow Hedge	Hedge method (a)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge	Hedge method (a)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method (b)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale
Other Non-Trading Derivative Activity	Mark-to-market method (c)	Net basis in gains and losses from commodity derivative activity

(a) Hedge method - An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery impacts earnings. For fair value hedges, the change in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations in the same category as the related hedged item.
(b) Accrual method - An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery impacts earnings.
(c) Mark-to-market method - An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations in gains and losses from commodity derivative activity during the current period.

Cash Flow and Fair Value Hedges - For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedging relationship and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. The change in fair value of the effective portion of a derivative designated as a cash flow hedge is recorded in partners' equity in accumulated other comprehensive income, or AOCI, and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same line item as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on derivative instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the results of operations.

Valuation - When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical relationships with quoted market prices and the expected relationship with quoted market prices.

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

Property, Plant and Equipment - Property, plant and equipment are recorded at historical cost. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Capitalized Interest - We capitalize interest during construction of major projects. Interest is calculated on the monthly outstanding capital balance and ceases in the month that the asset is placed into service. We also capitalize interest on our equity method investments which are devoting substantially all efforts to establishing a new business and have not yet begun planned principal operations. Capitalization ceases when the investee commences planned principal operations. The rates used to calculate capitalized interest are the weighted-average cost of debt, including the impact of interest rate swaps.

Asset Retirement Obligations - Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We adjust our asset retirement obligation each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Asset retirement obligations associated with tangible long-lived assets 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 accretes due to the passage of time based on the time value of money until the obligation is settled.

Goodwill and Intangible Assets - Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We perform an annual impairment test of goodwill at the reporting unit level during the third quarter, and update the test during interim periods when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of a reporting unit. We primarily use a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill and intangible assets impairment due to the potential impact on our operations and cash flows.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit. Intangible assets are removed from the gross carrying amount and the total of accumulated amortization in the period in which they become fully amortized.

Investments in Unconsolidated Affiliates - We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When there is evidence of loss in value that is other than temporary, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Long-Lived Assets - We periodically evaluate whether the carrying value of long-lived assets, including intangible assets, has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- significant adverse change in legal factors or business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management's intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

Unamortized Debt Discount and Expense - Discounts and expenses incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. The discounts are recorded on the consolidated balance sheets within the carrying amount of long-term debt. The unamortized expenses are recorded on the consolidated balance sheet as other long-term assets.

Noncontrolling Interest - Noncontrolling interest represents any third party or affiliate interest in non-wholly owned entities that we consolidate. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party or affiliate interest in our consolidated balance sheet amounts shown as noncontrolling interest in equity. Distributions to and contributions from noncontrolling interests represent cash payments to and cash contributions from, respectively, such third party and affiliate investors.

Revenue Recognition - We generate the majority of our revenues from gathering, compressing, treating, processing, transporting, storing and selling of natural gas, and producing, fractionating, transporting, storing and selling NGLs and recovering and selling condensate. Once natural gas is produced from wells, producers then seek to deliver the natural gas and its components to end-use markets. We realize revenues either by selling the residue natural gas, NGLs and condensate, or by receiving fees. We also generate revenue from transporting, storing and selling propane.

We obtain access to commodities and provide our midstream services principally under contracts that contain a combination of one or more of the following arrangements:

- *Fee-based arrangements* - Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, transporting or storing natural gas; and fractionating, storing and transporting NGLs. Our fee-based arrangements include natural gas arrangements pursuant to which we obtain natural gas at the wellhead or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.
- *Percent-of-proceeds/liquids arrangements* - Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas, NGLs and condensate based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas, NGLs

and condensate, regardless of the actual amount of the sales proceeds we receive. We keep the difference between the proceeds received and the amount remitted back to the producer. Under percent-of-liquids arrangements, we do not keep any amounts related to residue natural gas proceeds and only keep amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. Certain of these arrangements may also result in the producer retaining title to all or a portion of the residue natural gas and/or the NGLs, in lieu of us returning sales proceeds to the producer. Additionally, these arrangements may include fee-based components. Our revenues under percent-of-proceeds arrangements relate directly with the price of natural gas, NGLs and condensate. Our revenues under percent-of-liquids arrangements relate directly with the price of NGLs and condensate.

- *Propane sales arrangements* - Under propane sales arrangements, we generally purchase propane from natural gas processing plants and fractionation facilities, and crude oil refineries. We sell propane on a wholesale basis to propane distributors, who in turn resell to their customers. Our sales of propane are not contingent upon the resale of propane by propane distributors to their customers.

Our marketing of natural gas and NGLs consists of physical purchases and sales, as well as positions in derivative instruments.

We recognize revenues for sales and services under the four revenue recognition criteria, as follows:

- *Persuasive evidence of an arrangement exists* - Our customary practice is to enter into a written contract.
- *Delivery* - Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.
- *The fee is fixed or determinable* - We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.
- *Collectability is reasonably assured* - Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (for example, credit metrics, liquidity and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is not recognized until the cash is collected.

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody to the product, and incur the risks and rewards of ownership. We recognize revenues for non-trading commodity derivative activity net in the consolidated statements of operations as gains and losses from commodity derivative activity. These activities include mark-to-market gains and losses on energy trading contracts and the settlement of financial and physical energy trading contracts.

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as accounts receivable or accounts payable using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash.

Significant Customers - There were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2014, 2013 and 2012. We had significant transactions with affiliates.

Environmental Expenditures - Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations and that do not generate current or future revenue are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Environmental liabilities included in the consolidated balance sheets as other current liabilities was $1 million, and other long-term liabilities was $1 million at both December 31, 2014 and 2013.

Income Taxes - We are structured as a master limited partnership which is a pass-through entity for federal income tax purposes. Our income tax expense includes certain jurisdictions, including state, local, franchise and margin taxes of the master limited partnership and subsidiaries. We follow the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is proportionately included in the federal returns of each partner.

Net Income or Loss per Limited Partner Unit - Basic and diluted net income or loss per limited partner unit, or LPU, is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding LPUs during the period. Diluted net income or loss per limited partner unit is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method.

3. New Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2014-09 "Revenue from Contracts with Customers (Topic 606)," **or ASU 2014-09** - In May 2014, the FASB issued ASU 2014-09, which supersedes the revenue recognition requirements of Accounting Standards Codification, or ASC, Topic 605 "Revenue Recognition." This ASU is effective for annual reporting periods beginning after December 15, 2016 and we are currently assessing the impact of adoption on our consolidated results of operations, cash flows and financial position.

4. Acquisitions

On March 31, 2014, DCP Midstream, LLC and its affiliates contributed to us: (i) a 33.33% membership interest in DCP Sand Hills Pipeline, LLC, which owns the Sand Hills pipeline; (ii) a 33.33% membership interest in DCP Southern Hills Pipeline, LLC, which owns the Southern Hills pipeline; and (iii) the remaining 20% interest in DCP SC Texas GP, or the Eagle Ford system. The Sand Hills pipeline is engaged in the business of transporting NGLs and consists of approximately 1,025 miles of pipe, with a capacity of 200 MBbls/d, and possible further capacity increases with the installation of additional pump stations. The Sand Hills pipeline provides NGL takeaway service from the Permian and Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and at the Mont Belvieu, Texas market hub. The Sand Hills pipeline began taking flows in the fourth quarter of 2012 and was placed into service in June 2013. The Southern Hills pipeline is also engaged in the business of transporting NGLs and consists of approximately 940 miles of pipe, with a capacity of 175 MBbls/d. The Southern Hills pipeline provides NGL takeaway service from the Midcontinent to fractionation facilities at the Mont Belvieu, Texas market hub. The Southern Hills pipeline began taking flows in the first quarter of 2013 and was placed into service in June 2013.

On March 28, 2014, we acquired from DCP Midstream, LLC and its affiliates (i) a 35 MMcf/d cryogenic natural gas processing plant located in Weld County, Colorado, or the Lucerne 1 plant; and (ii) a 200 MMcf/d cryogenic natural gas processing plant also located in Weld County, Colorado, or the Lucerne 2 plant, which is currently under construction. The Lucerne 1 plant and Lucerne 2 plant, along with our O'Connor plant, comprises our DJ Basin system. In conjunction with our acquisition of the Lucerne 1 plant, we entered into a long-term fee-based processing agreement with DCP Midstream, LLC pursuant to which DCP Midstream, LLC agreed to pay us (i) a fixed demand charge of 75% of the plant's capacity, and (ii) a throughput fee on all volumes processed for DCP Midstream, LLC at the Lucerne 1 plant. The Lucerne 2 plant is expected to be completed in the second quarter of 2015 and we have assumed all of the remaining costs to complete this project. In addition, we entered into a ten-year, fee-based natural gas processing agreement with DCP Midstream, LLC that is effective once the Lucerne 2 plant is placed into service. At that time, the processing agreement with Lucerne 1 will be terminated. The new processing agreement initially provided a fixed demand charge on 75% of the capacity of and a throughput fee on all volumes processed at both plants once the Lucerne 2 plant is placed into service. In December 2014, we amended the agreement to provide a fixed demand charge on 43% of the capacity of both plants from the time that the Lucerne 2 plant is placed into service through the remainder of 2015 which was the original intent of the parties. Thereafter, the agreement will resume a fixed demand charge on 75% of the capacity of both plants. Except with respect to the fixed demand charge, there were no other changes to the agreement as a result of the December 2014 amendment. Together with the contribution of the interests in the Sand Hills and Southern Hills pipelines and the remaining 20% interest in the Eagle Ford system, the acquisition of the Lucerne 1 and 2 plants are collectively referred to hereafter as the March 2014 Transactions.

Total consideration for the March 2014 Transactions at closing was $1,220 million, less customary working capital and other adjustments. $225 million of the consideration was funded by the issuance at closing of 2,098,674 of our common units to DCP Midstream, LLC, 1,399,116 of our common units to DCP LP Holdings, LLC, and 999,368 of our common units to DCP Midstream GP, LP. The remainder of the consideration was financed by a portion of the issuance of 14,375,000 common units to the public and the proceeds from our 5.60% 30-year Senior Notes and 2.70% five-year Senior Notes offering. The total consideration over the carrying value of the net assets of the Sand Hills and Southern Hills pipelines, the remaining 20% of the Eagle Ford system, and the Lucerne 1 and Lucerne 2 plants resulted in an excess purchase price of $178 million which was recorded as a decrease in limited partners' equity in the consolidated statement of changes in equity.

The acquisition of the Lucerne 2 plant and contribution of the interests in the Sand Hills pipeline, the Southern Hills pipeline and the remaining 20% interest in the Eagle Ford system represent a transfer of assets between entities under common control. The results for these entities are included prospectively from the date of acquisition or contribution. The acquisition of the Lucerne 1 plant represents a transaction between entities under common control and a change in reporting entity. Accordingly, our consolidated financial statements have been adjusted to retrospectively include the historical results of the Lucerne 1 plant for all periods presented, similar to the pooling method. The results of the Sand Hills and Southern Hills pipelines are included in our NGL Logistics segment, and the remaining 20% interest in the Eagle Ford system and the Lucerne 1 and 2 plants are included in our Natural Gas Services segment.

The assets and liabilities of the Lucerne 1 plant are included in the consolidated balance sheets as of December 31, 2014 and December 31, 2013. The following table presents the previously reported December 31, 2013 consolidated balance sheet, condensed and adjusted for the acquisition of the Lucerne 1 plant from DCP Midstream, LLC:

As of December 31, 2013

	DCP Midstream Partners, LP (as previously reported on Form 10-K filed on 2/26/14)	Consolidate Lucerne 1 Plant	Consolidated DCP Midstream Partners, LP (As currently reported)
		(Millions)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 12	$ —	$ 12
Accounts receivable	342	—	342
Inventories	67	—	67
Other	82	—	82
Total current assets	503	—	503
Property, plant and equipment, net	3,005	41	3,046
Goodwill and intangible assets, net	283	—	283
Investments in unconsolidated affiliates	627	—	627
Other non-current assets	108	—	108
Total assets	$ 4,526	$ 41	$ 4,567
LIABILITIES AND EQUITY			
Accounts payable and other current liabilities	$ 722	$ 1	$ 723
Long-term debt	1,590	—	1,590
Other long-term liabilities	41	—	41
Total liabilities	2,353	1	2,354
Commitments and contingent liabilities			
Equity:			
Partners' equity			
Net equity	1,956	40	1,996
Accumulated other comprehensive loss	(11)	—	(11)
Total partners' equity	1,945	40	1,985
Noncontrolling interests	228	—	228
Total equity	2,173	40	2,213
Total liabilities and equity	$ 4,526	$ 41	$ 4,567

The results of the Lucerne 1 plant are included in the consolidated statements of operations for the years ended December 31, 2014, 2013 and 2012. The following tables present the previously reported consolidated statements of operations for the years ended December 31, 2013 and 2012, condensed and adjusted for the acquisition of the Lucerne 1 plant from DCP Midstream, LLC:

Year Ended December 31, 2013

	DCP Midstream Partners, LP (As previously reported on Form 10-K filed on 2/26/14)	Consolidate Lucerne 1 Plant	Consolidated DCP Midstream Partners, LP (As currently reported)
		(Millions)	
Sales of natural gas, propane, NGLs and condensate	$ 2,695	$ 68	$ 2,763
Transportation, processing and other	268	3	271
Gains from commodity derivative activity, net	17	—	17
Total operating revenues	2,980	71	3,051
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	2,381	45	2,426
Operating and maintenance expense	211	4	215
Depreciation and amortization expense	93	2	95
General and administrative expense	62	1	63
Other operating expense	8	—	8
Total operating costs and expenses	2,755	52	2,807
Operating income	225	19	244
Interest expense	(52)	—	(52)
Earnings from unconsolidated affiliates	33	—	33
Income before income taxes	206	19	225
Income tax expense	(8)	—	(8)
Net income	198	19	217
Net income attributable to noncontrolling interests	(17)	—	(17)
Net income attributable to partners	$ 181	$ 19	$ 200

Year Ended December 31, 2012

	DCP Midstream Partners, LP (As previously reported on Form 10-K filed on 2/26/14)	Consolidate Lucerne 1 plant	Consolidated DCP Midstream Partners, LP (As currently reported)
		(Millions)	
Sales of natural gas, propane, NGLs and condensate	$ 2,459	$ 61	$ 2,520
Transportation, processing and other	232	2	234
Losses from commodity derivative activity, net	70	—	70
Total operating revenues	2,761	63	2,824
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	2,177	38	2,215
Operating and maintenance expense	193	4	197
Depreciation and amortization expense	89	2	91
General and administrative expense	74	1	75
Total operating costs and expenses	2,533	45	2,578
Operating income	228	18	246
Interest expense	(42)	—	(42)
Earnings from unconsolidated affiliates	26	—	26
Income before income taxes	212	18	230
Income tax expense	(1)	—	(1)
Net income	211	18	229
Net income attributable to noncontrolling interests	(13)	—	(13)
Net income attributable to partners	$ 198	$ 18	$ 216

On July 3, 2012, we acquired the Crossroads processing plant and associated gathering system from Penn Virginia Resource Partners, L.P. for $63 million. The acquisition was financed at closing with borrowings under our revolving credit facility. The Crossroads system, located in the southeastern portion of Harrison County in East Texas, includes approximately 8 miles of gas gathering pipeline, an 80 MMcf/d cryogenic processing plant, approximately 20 miles of NGL pipeline and a 50% ownership interest in an approximately 11-mile residue gas pipeline, or CrossPoint Pipeline, LLC, which we accounted for as an unconsolidated affiliate using the equity method. The Crossroads system is a part of our East Texas system, which is included in our Natural Gas Services segment.

We accounted for the Crossroads business combination based on estimates of the fair value of assets acquired and liabilities assumed, including: property, plant and equipment; the equity investment in CrossPoint Pipeline, LLC; a liability for a firm transportation agreement which expires in 2015; and a gas purchase agreement under which a portion of those firm transportation payments are recoverable. Expected cash payments and receipts were recorded at their estimated fair value and are included in other current liabilities, other long-term liabilities, and accounts receivable as of the acquisition date. The following table summarizes the aggregate consideration and fair value of the identifiable assets acquired and liabilities assumed in the acquisition of Crossroads as of the acquisition date:

	July 3, 2012
	(Millions)
Aggregate consideration	$ 63
Accounts receivable	$ 4
Property, plant and equipment	63
Investments in unconsolidated affiliates	6
Other current liabilities	(4)
Other long-term liabilities	(6)
Total	$ 63

The results of operations for acquisitions accounted for as a business combination are included in our results subsequent to the date of acquisition. Accordingly, total operating revenues of $22 million and net income of $1 million associated with Crossroads from the acquisition date to December 31, 2012 are included in our consolidated statement of operations for the year ended December 31, 2012.

Supplemental pro forma information is presented for comparative periods prior to the date of acquisition; however, comparative periods in the consolidated financial statements are not adjusted to include the results of the acquisition. The following table presents unaudited supplemental pro forma information for the consolidated statement of operations for the year ended December 31, 2012, as if the acquisition of Crossroads had occurred at the beginning of the year.

	Year Ended December 31, 2012		
	DCP Midstream Partners, LP	Acquisition of Crossroads (a)	DCP Midstream Partners, LP Pro Forma
		(Millions)	
Total operating revenues	$ 2,824	$ 27	$ 2,851
Net income attributable to partners	$ 216	$ 2	$ 218
Less:			
Net income attributable to predecessor operations	(51)	—	(51)
General partner's interest in net income	(41)	—	(41)
Net income allocable to limited partners	$ 124	$ 2	$ 126
Net income per limited partner unit - basic and diluted	$ 2.28	$ 0.03	$ 2.31

(a) The year ended December 31, 2012 includes the financial results of Crossroads for the period from January 1, 2012 through July 2, 2012.

The supplemental pro forma total operating revenues for the year ended December 31, 2012 was adjusted to eliminate $5 million related to a contractual gas processing arrangement between us and Crossroads during the period.

The supplemental pro forma information is not intended to reflect actual results that would have occurred if the acquired business had been combined during the periods presented, nor is it intended to be indicative of the results of operations that may be achieved by us in the future.

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Services Agreement and Other General and Administrative Charges

We have entered into a services agreement, as amended, or the Services Agreement, with DCP Midstream, LLC. Under the Services Agreement, which replaced the Omnibus Agreement on February 14, 2013, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee under the Services Agreement for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. Except with respect to the annual fee, there is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for other expenses and expenditures incurred or payments made on our behalf. In the event we acquire assets or our business otherwise expands, the annual fee under the Services Agreement is subject to adjustment based on the nature and extent of general and administrative services performed by DCP Midstream, LLC, as well as an annual adjustment based on changes to the Consumer Price Index.

On March 31, 2014, the annual fee payable under the Services Agreement was increased by approximately $15 million, prorated for the remainder of the calendar year, to $44 million. The increase was predominantly attributable to additional general and administrative expenses previously incurred directly by the Eagle Ford system being reallocated to the Services Agreement in connection with the contribution of the remaining 20% interest in the Eagle Ford system to us, bringing our ownership to 100%.

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

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

	Year Ended December 31,		
	2014	2013	2012
		(Millions)	
Services/Omnibus Agreement	$ 41	$ 29	$ 26
Other fees — DCP Midstream, LLC	6	17	32
Total — DCP Midstream, LLC	$ 47	$ 46	$ 58

In addition to the fees paid pursuant to the Services Agreement, we incurred allocated expenses, including executive compensation, insurance and internal audit fees with DCP Midstream, LLC of $2 million, $2 million and $1 million for the years ended December 31, 2014, 2013 and 2012, respectively. The Lucerne 1 plant incurred $1 million in general and administrative expenses directly from DCP Midstream, LLC for the years ended December 31, 2013 and 2012. The Eagle Ford system incurred $4 million, $14 million and $27 million in general and administrative expenses directly from DCP Midstream, LLC for the years ended December 31, 2014, 2013 and 2012, respectively, before the reallocation of the Eagle Ford system to the Services Agreement on March 31, 2014. For the year ended December 31, 2012, Southeast Texas incurred $3 million in general and administrative expenses directly from DCP Midstream, LLC, before the addition of Southeast Texas to the Omnibus Agreement in March 2012.

Competition

None of DCP Midstream, LLC, or any of its affiliates, including Phillips 66 and Spectra Energy, is restricted, under either the partnership agreement or the Services Agreement, from competing with us. DCP Midstream, LLC and any of its affiliates, including Phillips 66 and Spectra Energy, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Other Agreements and Transactions with DCP Midstream, LLC

DCP Midstream, LLC was a significant customer during the years ended December 31, 2014, 2013 and 2012. We sell a portion of our residue gas, NGLs and condensate to, purchase natural gas and other petroleum products from, and provide gathering and transportation services for, DCP Midstream, LLC. We anticipate continuing to purchase from and sell commodities and services to DCP Midstream, LLC in the ordinary course of business. In addition, DCP Midstream, LLC conducts derivative activities on our behalf. We have and may continue to enter into derivative transactions directly with DCP Midstream, LLC, whereby DCP Midstream, LLC is the counterparty.

We have a contractual arrangement with DCP Midstream, LLC, through March 2022, in which we pay DCP Midstream, LLC a fee for processing services associated with the gas we gather on our Southern Oklahoma system, which is part of our Natural Gas Services segment. In addition, we have an agreement with DCP Midstream, LLC providing for adjustments to those fees based upon plant efficiencies related to our portion of volumes from the Southern Oklahoma system being processed at DCP Midstream, LLC’s plant through March 2022. We generally report fees associated with these activities in the consolidated statements of operations as purchases of natural gas, propane and NGLs from affiliates. In addition, as part of this arrangement, DCP Midstream, LLC pays us a fee for certain gathering services. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system, included in our Northern Louisiana system, which is part of our Natural Gas Services segment, that are periodically used for the benefit of Pelico. DCP Midstream, LLC is able to source natural gas upstream of Pelico and deliver it to us and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. We purchase natural gas from DCP Midstream, LLC upstream of Pelico and transport it to Pelico under an interruptible transportation agreement with an affiliate. Our purchases from DCP Midstream, LLC are at DCP Midstream, LLC’s actual acquisition cost plus any transportation service charges. Volumes that exceed our on-system demand are sold to DCP Midstream, LLC at an index-based price, less contractually agreed upon marketing fees. Revenues associated with these activities are reported gross in our consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates.

In our Natural Gas Services segment, we sell NGLs processed at certain of our plants, and sell condensate removed from the gas gathering systems that deliver to certain of our systems under contracts to a subsidiary of DCP Midstream, LLC equal to that subsidiary’s net weighted-average sales price, adjusted for transportation, processing and other charges from the tailgate of the respective asset. In conjunction with our acquisitions of our East Texas and Southeast Texas systems, which are part of our Natural Gas Services segment, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse us for certain expenditures on East Texas and Southeast Texas capital projects. These reimbursements are for specific capital projects which have commenced within three years from the respective acquisition dates. DCP Midstream, LLC made capital contributions to East Texas for capital projects of $1 million and $5 million for the years ended December 31, 2013 and 2012 respectively. DCP Midstream, LLC made capital contributions to Southeast Texas for capital projects of $5 million for the year ended December 31, 2012. We made a distribution to DCP Midstream, LLC related to capital projects at Southeast Texas of $3 million for the year ended December 31, 2013.

In conjunction with our acquisition of the O'Connor and Lucerne 1 plants, we entered into long-term fee-based processing agreements with DCP Midstream, LLC pursuant to which DCP Midstream, LLC agreed to pay us (i) a fixed demand charge on a portion of the plants' capacities, and (ii) a throughput fee on all volumes processed for DCP Midstream, LLC at the plants. We report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates. Under the O'Connor agreement, we received fees of $35 million and $6 million during the years ended December 31, 2014 and 2013, respectively. Under the Lucerne 1 agreement, we received fees of $10 million during the year ended December 31, 2014.

As a result of a downstream outage, certain of our assets were required to curtail NGL production during 2012. DCP Midstream, LLC has reimbursed us for the impact of the curtailment and accordingly, we recorded $3 million to sales of natural gas, propane, NGLs and condensate to affiliates and less than $1 million to transportation, processing and other to affiliates in the consolidated statements of operations for the year ended December 31, 2012.

In our NGL Logistics segment, we also have a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze and Wilbreeze pipelines, pursuant to fee-based rates that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on these pipelines under the transportation agreements. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

The Wattenberg pipeline has in place a 10-year dedication and transportation agreement with a subsidiary of DCP Midstream, LLC whereby certain NGL volumes produced at several of DCP Midstream, LLC's processing facilities are dedicated for transportation on the Wattenberg pipeline. We collect fee-based transportation revenues under our tariff. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

In addition to agreements with other third party shippers, the Texas Express, Front Range, Sand Hills and Southern Hills pipelines have in place 15-year transportation agreements, commencing at the pipelines' respective in-service dates, with DCP Midstream, LLC pursuant to which DCP Midstream, LLC has committed to transport minimum throughput volumes at rates defined in each respective pipeline's tariffs.

We pay a fee to DCP Midstream, LLC to operate our DJ Basin NGL fractionators and receive fees for the processing of DCP Midstream, LLC's committed NGLs produced by them in Colorado at our DJ Basin NGL fractionators under agreements that are effective through March 2018. We report fees associated with these activities in the consolidated statements of operations as operating and maintenance expense.

Spectra Energy

We had propane supply agreements with Spectra Energy that expired in April 2012, which provided us propane supply at our marine terminals, included in our Wholesale Propane Logistics segment, for up to approximately 185 million gallons of propane annually.

Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Year Ended December 31, 2014	2013	2012
		(Millions)	
DCP Midstream, LLC:			
Sales of natural gas, propane, NGLs and condensate	$ 2,179	$ 1,830	$ 1,691
Transportation, processing and other	$ 92	$ 60	$ 52
Purchases of natural gas, propane and NGLs	$ 194	$ 204	$ 173
Gains from commodity derivative activity, net	$ 118	$ 22	$ 53
Operating and maintenance expense	$ 1	$ 1	$ 1
General and administrative expense	$ 47	$ 46	$ 58
Phillips 66:			
Sales of natural gas, propane, NGLs and condensate	$ 1	$ 1	$ —
ConocoPhillips:			
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 9
Transportation, processing and other	$ —	$ —	$ 3
Purchases of natural gas, propane and NGLs	$ —	$ —	$ 67
Spectra Energy:			
Purchases of natural gas, propane and NGLs	$ 77	$ 63	$ 166
Transportation, processing and other	$ 14	$ —	$ —
Unconsolidated affiliates:			
Purchases of natural gas, propane and NGLs	$ —	$ —	$ 2

We had balances with affiliates as follows:

	December 31, 2014	December 31, 2013
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 163	$ 211
Accounts payable	$ 24	$ 37
Unrealized gains on derivative instruments — current	$ 207	$ 79
Unrealized gains on derivative instruments — long-term	$ 25	$ 81
Unrealized losses on derivative instruments — current	$ 43	$ 18
Unrealized losses on derivative instruments — long-term	$ —	$ 1
Spectra Energy:		
Accounts receivable	$ 1	$ 1
Accounts payable	$ 3	$ 6

6. Inventories

Inventories were as follows:

	December 31, 2014	December 31, 2013
	(Millions)	
Natural gas	$ 36	$ 38
NGLs	27	29
Total inventories	$ 63	$ 67

We recognize lower of cost or market adjustments when the carrying value of our inventories exceeds their estimated market value. These non-cash charges are a component of purchases of natural gas, propane and NGLs in the consolidated statements of operations. We recognized $24 million, $4 million and $19 million in lower of cost or market adjustments during the years ended December 31, 2014, 2013 and 2012, respectively.

7. Property, Plant and Equipment

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

	Depreciable Life	December 31, 2014	December 31, 2013
		(Millions)	
Gathering and transmission systems	20 — 50 Years	$ 2,209	$ 2,205
Processing, storage, and terminal facilities	35 — 60 Years	2,071	1,645
Other	3 — 30 Years	50	49
Construction work in progress		281	310
Property, plant and equipment		4,611	4,209
Accumulated depreciation		(1,264)	(1,163)
Property, plant and equipment, net		$ 3,347	$ 3,046

Interest capitalized on construction projects for the years ended December 31, 2014, 2013 and 2012 was $8 million, $11 million and $7 million, respectively.

We revised the depreciable lives for our gathering and transmission systems, processing, storage and terminal facilities, and other assets effective April 1, 2012. The key contributing factors to the change in depreciable lives is an increase in the producers' estimated remaining economically recoverable reserves resulting from the widespread application of techniques, such as hydraulic fracturing and horizontal drilling, that improve commodity production in the regions our assets serve. Advances in extraction processes, along with better technology used to locate commodity reserves, is giving producers greater access to unconventional commodities. Based on our property, plant and equipment as of April 1, 2012, the new remaining depreciable lives resulted in an approximate $52 million reduction in depreciation expense for the year ended December 31, 2012. This change in our estimated depreciable lives increased net income per limited partner unit by $0.95 for the year ended December 31, 2012.

Depreciation expense was $101 million, $87 million and $83 million for the years ended December 31, 2014, 2013 and 2012, respectively.

During the years ended December 31, 2014 and 2013, we discontinued certain construction projects and wrote off approximately $3 million and $8 million, respectively, in construction work in progress to other expense in the consolidated statements of operations. We had no write-offs during the year ended December 31, 2012.

Asset Retirement Obligations - As of December 31, 2014 and 2013, we had asset retirement obligations of $27 million and $24 million, respectively, included in other long-term liabilities in the consolidated balance sheets. During the year ended December 31, 2014, we recorded a change in estimate to increase our asset retirement obligations by $1 million. The change in estimate was primarily attributable to a reassessment of anticipated timing of settlements and of the original asset retirement obligation amounts. Accretion expense was $2 million and $1 million for the years ended December 31, 2014 and 2013 and accretion benefit was less than $1 million for the year ended December 31, 2012.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

8. Goodwill and Intangible Assets

The carrying value of goodwill as of both December 31, 2014 and December 31, 2013 was $154 million, consisting of $82 million for our Natural Gas Services segment, $35 million for our NGL Logistics segment, and $37 million for our Wholesale Propane Logistics segment.

We performed our annual goodwill assessment at the reporting unit level, which is identified by assessing whether any components of our operating segments constitute businesses for which discrete financial information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. As a result of our assessment, we concluded that the fair value of goodwill exceeded its carrying value and that the entire amount of goodwill disclosed on the consolidated balance sheet is recoverable. We primarily used a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill impairment for reporting units due to the potential impact on our operations and cash flows.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and are as follows:

	December 31,	
	2014	2013
	(Millions)	
Gross carrying amount	$ 164	$ 164
Accumulated amortization	(44)	(35)
Intangible assets, net	$ 120	$ 129

We recorded amortization expense of $9 million for the year ended December 31, 2014, and $8 million for each of the years ended December 31, 2013, and 2012. As of December 31, 2014, the remaining amortization periods ranged from approximately 7 years to 21 years, with a weighted-average remaining period of approximately 16 years.

Estimated future amortization for these intangible assets is as follows:

Estimated Future Amortization		
	(Millions)	
2015	$	8
2016		8
2017		8
2018		8
2019		8
Thereafter		80
Total	$	120

9. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

		Carrying Value as of			
	Percentage Ownership	December 31, 2014		December 31, 2013	
		(Millions)			
DCP Sand Hills Pipeline, LLC	33.33%	$	413	$	—
Discovery Producer Services LLC	40%		406		348
DCP Southern Hills Pipeline, LLC	33.33%		329		—
Front Range Pipeline LLC	33.33%		169		134
Texas Express Pipeline LLC	10%		98		96
Mont Belvieu Enterprise Fractionator	12.5%		23		26
Mont Belvieu 1 Fractionator	20%		14		16
Other	Various		7		7
Total investments in unconsolidated affiliates		$	1,459	$	627

There was an excess of the carrying amount of the investment over the underlying equity of Sand Hills of $10 million at December 31, 2014 which is associated with interest capitalized during the construction of the Sand Hills pipeline and is being amortized over the life of the underlying long-lived assets of Sand Hills pipeline.

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $25 million and $28 million at December 31, 2014 and 2013, respectively, which is associated with, and is being amortized over, the life of the underlying long-lived assets of Discovery.

There was an excess of the carrying amount of the investment over the underlying equity of Southern Hills of $8 million at December 31, 2014 which is associated with interest capitalized during the construction of the Southern Hills pipeline and is being amortized over the life of the underlying long-lived assets of Southern Hills pipeline.

There was an excess of the carrying amount of the investment over the underlying equity of Front Range of $5 million and $4 million at December 31, 2014 and 2013, respectively, which is associated with interest capitalized during the construction of the pipeline and is being amortized over the life of the underlying long-lived assets of Front Range pipeline.

There was an excess of the carrying amount of the investment over the underlying equity of Texas Express of $3 million at December 31, 2014 and 2013, respectively, which is associated with interest capitalized during the construction of the pipeline and is being amortized over the life of the underlying long-lived assets of Texas Express.

There was a deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu 1 of $4 million and $5 million at December 31, 2014 and 2013, respectively, which is associated with, and is being amortized over the life of the underlying long-lived assets of Mont Belvieu 1.

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

	Year Ended December 31, 2014	2013	2012
	(Millions)		
DCP Sand Hills Pipeline, LLC	$ 24	$ —	$ —
Mont Belvieu Enterprise Fractionator	16	14	5
DCP Southern Hills Pipeline, LLC	13	—	—
Mont Belvieu 1 Fractionator	12	19	6
Discovery Producer Services LLC	5	1	15
Texas Express Pipeline LLC	3	(1)	—
Front Range Pipeline LLC	2	—	—
Total earnings from unconsolidated affiliates	$ 75	$ 33	$ 26

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

	Year Ended December 31, 2014	2013	2012
	(Millions)		
Statements of operations:			
Operating revenue	$ 826	$ 484	$ 293
Operating expenses	$ 475	$ 298	$ 190
Net income	$ 349	$ 186	$ 103

	December 31, 2014	December 31, 2013
	(Millions)	
Balance sheets:		
Current assets	$ 207	$ 182
Long-term assets	5,157	2,678
Current liabilities	(200)	(276)
Long-term liabilities	(164)	(37)
Net assets	$ 5,000	$ 2,547

10. Fair Value Measurement

Determination of Fair Value

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

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.

- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability positions with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.

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

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

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 12 - Risk Management and Hedging Activities.

Valuation Hierarchy

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

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.

- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

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

Commodity Derivative Assets and Liabilities

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

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

Within our Wholesale Propane Logistics segment, we may enter into a variety of financial instruments to either secure sales or purchase prices, or capture a variety of market opportunities. Since financial instruments for NGLs tend to be counterparty and location specific, we primarily use the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third party pricing services, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

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

Interest Rate Derivative Assets and Liabilities

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

Nonfinancial Assets and Liabilities

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

The following table presents the financial instruments carried at fair value as of December 31, 2014 and December 31, 2013, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets:								
Commodity derivatives (a)	$ —	$ 92	$ 138	$ 230	$ —	$ 14	$ 65	$ 79
Short-term investments (b)	$ 24	$ —	$ —	$ 24	$ 9	$ —	$ —	$ 9
Long-term assets (c):								
Commodity derivatives	$ —	$ 21	$ 18	$ 39	$ —	$ 12	$ 75	$ 87
Current liabilities (d):								
Commodity derivatives	$ —	$ (43)	$ —	$ (43)	$ —	$ (26)	$ —	$ (26)
Interest rate derivatives	$ —	$ —	$ —	$ —	$ —	$ (2)	$ —	$ (2)
Long-term liabilities (e):								
Commodity derivatives	$ —	$ —	$ —	$ —	$ —	$ (1)	$ —	$ (1)

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

Changes in Levels 1 and 2 Fair Value Measurements

The determination to classify a financial instrument within Level 1 or Level 2 is based upon the availability of quoted prices for identical or similar assets and liabilities in active markets. Depending upon the information readily observable in the market, and/or the use of identical or similar quoted prices, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level during the current period. In the event that there is a movement between the classification of an instrument as Level 1 or 2, the transfer would be reflected in a table as Transfers into or out of Level 1 and Level 2. During the years ended December 31, 2014 and 2013, there were no transfers into or out of Level 1 and Level 2 of the fair value hierarchy.

Changes in Level 3 Fair Value Measurements

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

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

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Year ended December 31, 2014 (a):				
Beginning balance	$ 65	$ 75	$ —	$ —
Net realized and unrealized gains (losses) included in earnings (c)	150	(57)	—	—
Transfers out of Level 3 (b)	—	—	—	—
Settlements	(77)	—	—	—
Purchases	—	—	—	—
Ending balance	$ 138	$ 18	$ —	$ —
Net unrealized gains (losses) on derivatives still held included in earnings (c)	$ 138	$ (57)	$ —	$ —
Year ended December 31, 2013 (a):				
Beginning balance	$ 40	$ 65	$ (1)	$ —
Net realized and unrealized gains (losses) included in earnings (c)	42	(50)	—	—
Transfers out of Level 3 (b)	(1)	(2)	1	—
Settlements	(40)	—	—	—
Purchases	24	62	—	—
Ending balance	$ 65	$ 75	$ —	$ —
Net unrealized gains (losses) on derivatives still held included in earnings (c)	$ 41	$ (50)	$ —	$ —

(a) There were no issuances or sales of derivatives or transfers into Level 3 for the years ended December 31, 2014 and 2013.
(b) Amounts transferred into/out of Level 3 are reflected at fair value as of the end of the period.
(c) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3.

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

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

	December 31, 2014		
Product Group	Fair Value	Forward Curve Range	
	(Millions)		
Assets			
NGLs	$ 156	$0.17-$1.13	Per gallon

Estimated Fair Value of Financial Instruments

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

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

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

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

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

We determine the fair value of our fixed-rate Senior Notes, based on quotes obtained from bond dealers. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy. As of December 31, 2014 and December 31, 2013, the carrying value and fair value of our long-term fixed-rate Senior Notes, including current maturities, were as follows:

	December 31, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(Millions)			
Long-Term Senior Notes	$ 2,311	$ 2,334	$ 1,590	$ 1,573

11. Debt

	December 31, 2014	December 31, 2013
	(Millions)	
Commercial Paper		
Short-term borrowings, weighted-average interest rate of 1.14% as of December 31, 2013	$ —	$ 335
Debt Securities		
Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015	250	250
Issued November 27, 2012, interest at 2.50% payable semi-annually, due December 1, 2017	500	500
Issued March 13, 2014, interest at 2.70% payable semi-annually, due April 1, 2019	325	—
Issued March 13, 2012, interest at 4.95% payable semi-annually, due April 1, 2022	350	350
Issued March 14, 2013, interest at 3.875% payable semi-annually, due March 15, 2023	500	500
Issued March 13, 2014, interest at 5.60% payable semi-annually, due April 1, 2044	400	—
Unamortized discount	(14)	(10)
Total debt	2,311	1,925
Short-term borrowings	—	(335)
Current maturities of long-term debt	(250)	—
Total long-term debt	$ 2,061	$ 1,590

Amended and Restated Credit Agreement

On May 1, 2014, we entered into a $1.25 billion amended and restated senior unsecured revolving credit agreement that matures on May 1, 2019, or the Amended and Restated Credit Agreement. The Amended and Restated Credit Agreement replaced our previous Credit Agreement dated as of November 10, 2011, which had a total borrowing capacity of $1 billion and would have matured on November 10, 2016. The Amended and Restated Credit Agreement will be used for working capital requirements and other general partnership purposes including acquisitions.

Indebtedness under the Amended and Restated Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.275% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.275% based on our current credit rating. The Amended and Restated Credit Agreement incurs an annual facility fee of 0.225% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $1.25 billion Amended and Restated Credit Agreement.

As of December 31, 2014, the unused capacity under the Amended and Restated Credit Agreement was $1,249 million, which is net of letters of credit. Our borrowing capacity may be limited by the Amended and Restated Credit Agreement's financial covenant requirements. Except in the case of a default, amounts borrowed under our Amended and Restated Credit Agreement will not become due prior to the May 1, 2019 maturity date.

The Amended and Restated Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 5.0 to 1.0, and following the consummation of qualifying acquisitions, not more than 5.5 to 1.0, on a temporary basis for three consecutive quarters, including the quarter in which such acquisition is consummated. Further, our cost of borrowing under the Amended and Restated Credit Agreement is determined by a ratings based pricing grid. Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, interest rates and fees under the DCP Partners Amended and Restated Credit Agreement have increased.

Commercial Paper Program

We have a commercial paper program, or the Commercial Paper Program, under which we may issue unsecured commercial paper notes. Amounts available under this program may be borrowed, repaid, and re-borrowed from time to time with the maximum aggregate principal amount of notes outstanding, combined with the amount outstanding under our Amended and Restated Credit Agreement, not to exceed $1.25 billion in the aggregate. As of December 31, 2014, we had no commercial paper outstanding. Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, we longer have access to the Commercial Paper Program. Our available liquidity under the Commercial Paper Program will be replaced with borrowings under the DCP Partners Amended and Restated Credit Agreement.

Debt Securities

In March 2014, we issued $325 million of 2.70% five-year Senior Notes due April 1, 2019 and $400 million of 5.60% 30-year Senior Notes due April 1, 2044. We received proceeds of $320 million and $392 million, respectively, net of underwriters' fees, related expenses and unamortized discounts which we used to pay a portion of the consideration for the March 2014 Transactions. Interest on the notes is paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2014. The notes will mature on April 1, 2019 and April 1, 2044, respectively, unless redeemed prior to maturity.

In March 2013, we issued $500 million of 3.875% 10-year Senior Notes due March 15, 2023. We received proceeds of $490 million, net of underwriters' fees, related expenses and unamortized discounts, which we used to fund a portion of the purchase price for the acquisition of an additional 46.67% interest in the Eagle Ford system. Interest on the notes is paid semi-annually on March 15 and September 15 of each year, commencing September 15, 2013. The notes will mature on March 15, 2023, unless redeemed prior to maturity.

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

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

	Debt Maturities
	(Millions)
2015	$ 250
2016	—
2017	500
2018	—
2019	325
Thereafter	1,250
	2,325
Unamortized discount	(14)
Total	$ 2,311

12. Risk Management and Hedging Activities

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

Commodity Price Risk

Cash Flow Protection Activities — We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering, processing and storage services, we may receive cash or commodities as payment for these services, depending on the contract type. We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2017 with commodity derivative instruments. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices; however, there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. The relationship of NGLs to crude oil continues to be lower than historical relationships; however, a significant amount of our NGL hedges from 2014 through 2016 are direct product hedges. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. Our crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange our floating price risk for a fixed price. We also utilize crude oil costless collars that minimize our floating price risk by establishing a fixed price floor and a fixed price ceiling. However, the type of instrument that we use to mitigate a portion of our risk may vary depending upon our risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected within our consolidated statements of operations as a gain or a loss on commodity derivative activity.

Our Wholesale Propane Logistics segment is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. However, to the extent that we carry propane inventories or our sales and supply arrangements are not aligned, we are exposed to market variables and commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions, including fixed price sales. While the majority of our sales and purchases in this segment are index-based, occasionally, we may enter into fixed price sales agreements in the event that a propane distributor desires to purchase propane from us on a fixed price basis. In such cases, we may manage this risk with derivatives that allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may use financial derivatives to manage the value of our propane inventories. These transactions are not designated as hedging instruments for accounting purposes and any change in fair value is reflected in the current period within our consolidated statements of operations as a gain or loss on commodity derivative activity.

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting, whereby changes in fair value are recorded directly to the consolidated statements of operations; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting.

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

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

Commodity Cash Flow Hedges — In order for storage facilities to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. During construction or expansion of our storage caverns, we may execute a series of derivative financial instruments to mitigate a portion of the risk associated with the forecasted purchase of natural gas when we bring the storage caverns to operation. These derivative financial instruments may be designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixes the cash required to purchase the base gas, the deferred losses or gains would remain in accumulated other comprehensive income, or AOCI, until the cavern is emptied and the base gas is sold. The balance in AOCI of our previously settled base gas cash flow hedges was in a loss position of $6 million as of December 31, 2014.

Interest Rate Risk

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

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

In conjunction with the issuance of our 4.95% Senior Notes in March 2012, we entered into forward-starting interest rate swap agreements to reduce our exposure to market rate fluctuations prior to issuance. These derivative financial instruments were designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixed the rate we would pay on a portion of our 4.95% Senior Notes, the deferred loss in AOCI will be amortized into interest expense through the maturity of the notes in 2022. The balance in AOCI of these cash flow hedges was in a loss position of $4 million as of December 31, 2014.

Contingent Credit Features

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

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

- If we were to have an effective event of default under our Amended and Restated Credit Agreement that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.
- In the event that we were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties would have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.
- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under other credit arrangements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Amended and Restated Credit Agreement. As of December 31, 2014, we were not a party to any agreements that would trigger the cross-default provisions.

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

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or to our interest rate swap instruments are in either a net asset or net liability position. As of December 31, 2014, all of our individual commodity derivative contracts that contain credit-risk related contingent features were in a net asset position. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA contracts permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of December 31, 2014, if a credit-risk related event were to occur, we would not have been required to post additional collateral or offset net liability contracts with contracts in a net asset position because all of our commodity derivative contracts that contain credit-risk related contingent features were in a net asset position at that time.

Unconsolidated Affiliates

Discovery, one of our unconsolidated affiliates, entered into agreements with a pipe vendor denominated in a foreign currency in connection with the expansion of the natural gas gathering pipeline system in the deepwater Gulf of Mexico, the Keathley Canyon Connector. Discovery entered into certain foreign currency derivative contracts to mitigate a portion of the foreign currency exchange risks which were designated as cash flow hedges. As these hedges are owned by Discovery, an unconsolidated affiliate, and designated as cash flow hedges, we include the impact to AOCI on our consolidated balance sheet.

Offsetting

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

	December 31, 2014			December 31, 2013		
	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount
	(Millions)					
Assets:						
Commodity derivatives	$ 269	$ (42)	$ 227	$ 166	$ (13)	$ 153
Liabilities:						
Commodity derivatives	$ (43)	$ 42	$ (1)	$ (27)	$ 13	$ (14)
Interest rate derivatives	$ —	$ —	$ —	$ (2)	$ —	$ (2)

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

Summarized Derivative Information

The fair value of our derivative instruments that are marked-to-market each period, as well as the location of each within our consolidated balance sheets, by major category, is summarized below. We have no derivative instruments that are designated as hedging instruments for accounting purposes as of December 31, 2014 and 2013.

Balance Sheet Line Item	December 31, 2014	December 31, 2013	Balance Sheet Line Item	December 31, 2014	December 31, 2013
	(Millions)			(Millions)	
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments — current	$ 230	$ 79	Unrealized losses on derivative instruments — current	$ (43)	$ (26)
Unrealized gains on derivative instruments — long-term	39	87	Unrealized losses on derivative instruments — long-term	—	(1)
	$ 269	$ 166		$ (43)	$ (27)
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments — current	$ —	$ —	Unrealized losses on derivative instruments — current	$ —	$ (2)
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	—
	$ —	$ —		$ —	$ (2)

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

	Interest Rate Cash Flow Hedges		Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
			(Millions)		
Net deferred (losses) gains in AOCI (beginning balance)	$ (6)		$ (6)	$ 1	$ (11)
Losses reclassified from AOCI to earnings — effective portion	2	(b) (c)	—	—	2
Net deferred (losses) gains in AOCI (ending balance)	$ (4)		$ (6)	$ 1	$ (9)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ (1)		$ —	$ —	$ (1)

(a) Relates to Discovery, our unconsolidated affiliate.
(b) Included in interest expense in our consolidated statements of operations.
(c) For the year ended December 31, 2014, $1 million of derivative losses were reclassified from AOCI to interest expense as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

For the year ended December 31, 2014, no derivative losses attributable to the ineffective portion and amount excluded from effectiveness testing was recognized in gains or losses from commodity derivative activity, net and interest expense in our consolidated statements of operations.

The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the year ended December 31, 2013:

	Interest Rate Cash Flow Hedges		Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
			(Millions)		
Net deferred (losses) gains in AOCI (beginning balance)	$ (10)		$ (6)	$ 1	$ (15)
Losses reclassified from AOCI to earnings — effective portion	$ 4	(b)	$ —	$ —	$ 4
Net deferred losses in AOCI (ending balance)	$ (6)		$ (6)	$ 1	$ (11)

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

For the year ended December 31, 2013, less than $1 million of derivative losses attributable to the ineffective portion was recognized in gains or losses from commodity derivative activity, net and interest expense in our consolidated statements of operations. For the year ended December 31, 2013, $1 million of derivative gains or losses were reclassified from AOCI to current period earnings as a result of amounts excluded from effectiveness testing or as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

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

Commodity Derivatives: Statements of Operations Line Item	Year Ended December 31,		
	2014	2013	2012
		(Millions)	
Third party:			
Realized (losses) gains	$ (2)	$ (19)	$ 4
Unrealized gains	38	14	13
Gains (losses) from commodity derivative activity, net	$ 36	$ (5)	$ 17
Affiliates:			
Realized gains	$ 70	$ 73	$ 45
Unrealized gains (losses)	48	(51)	8
Gains from commodity derivative activity, net — affiliates	$ 118	$ 22	$ 53

Interest Rate Derivatives: Statements of Operations Line Item	Year Ended December 31,		
	2014	2013	2012
		(Millions)	
Third party:			
Realized losses	$ (2)	$ (2)	$ (7)
Unrealized gains	2	2	7
Interest expense	$ —	$ —	$ —

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

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

	December 31, 2014			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net (Short) Position (Bbls)	Net (Short) Position (MMBtu)	Net (Short) Position (Bbls)	Net Long Position (MMBtu)
2015	(745,695)	(20,803,975)	(5,573,570)	2,640,000
2016	(561,922)	(5,668,564)	(813,267)	1,690,000
2017	—	(6,387,500)	—	—

	December 31, 2013			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net (Short) Position (Bbls)	Net (Short) Position (MMBtu)	Net (Short) Position (Bbls)	Net Long Position (MMBtu)
2014	(690,945)	(21,673,620)	(5,171,910)	21,415,000
2015	(745,695)	(9,458,975)	(5,691,570)	1,875,000
2016	(561,922)	(1,838,564)	(813,267)	—

We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of December 31, 2013, we had swaps with a notional value of $70 million and $80 million, which, in aggregate, exchanged $150 million of our floating rate obligation to a fixed rate obligation through June 2014.

13. Partnership Equity and Distributions

In June 2014, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of $500 million, which became effective on July 11, 2014. The shelf registration statement allows us to issue additional common units. In September 2014, we entered into an equity distribution agreement, or the 2014 equity distribution agreement, with a group of financial institutions as sales agents. The 2014 equity distribution agreement provides for the offer and sale from time to time, through our sales agents, of common units having an aggregate offering amount of up to $500 million. During the year ended December 31, 2014, we issued 2,256,066 of our common units pursuant to the 2014 equity distribution agreement and received proceeds of $119 million, net of commissions and accrued offering costs of $1 million, which were used to finance growth opportunities and for general partnership purposes. As of December 31, 2014, approximately $380 million remained available for sale pursuant to the 2014 equity distribution agreement.

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

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

In August 2013, we issued 9,000,000 common units to the public at $50.04 per unit. We received proceeds of $434 million, net of offering costs.

In June 2013, we filed a shelf registration statement on Form S-3, or the June 2013 shelf registration statement, with the SEC with a maximum offering price of $300 million, which became effective on June 27, 2013. The June 2013 shelf registration statement allowed us to issue additional common units. In November 2013, we entered into an equity distribution agreement related to the June 2013 shelf registration statement, or the 2013 equity distribution agreement, with a group of financial institutions as sales agents. The 2013 equity distribution agreement provided for the offer and sale from time to time, through our sales agents, of common units having an aggregate offering amount of up to $300 million. During the year ended December 31, 2014, we issued 3,769,635 common units pursuant to the 2013 equity distribution agreement and received proceeds of $206 million, which is net of commissions and offering costs of $2 million. During the year ended December 31, 2013, we issued 1,839,430 of our common units pursuant to the 2013 equity distribution agreement and received proceeds of $87 million, net of commissions and offering costs of $1 million. The proceeds were used to finance growth opportunities and for general partnership purposes. In connection with our entry into the 2014 equity distribution agreement, we terminated the

2013 equity distribution agreement in September 2014. In October 2014, we de-registered the common units that remained unsold under the 2013 equity distribution agreement at the time of its termination.

In March 2013, we issued 2,789,739 common units to DCP Midstream, LLC as partial consideration for 46.67% interest in the Eagle Ford system.

In March 2013, we issued 12,650,000 common units to the public at $40.63 per unit. We received proceeds of $494 million, net of offering costs.

In November 2012, we issued 1,912,663 common units to DCP Midstream, LLC as partial consideration for our 33.33% interest in the Eagle Ford system.

In July 2012, we issued 1,536,098 common units to DCP Midstream, LLC as partial consideration for the Mont Belvieu fractionators.

In July 2012, we closed a private placement of equity with a group of institutional investors in which we sold 4,989,802 common units at a price of $35.55 per unit, and received proceeds of $174 million, net of offering costs.

In June 2012, we filed a universal shelf registration statement on Form S-3 with the SEC with an unlimited offering amount, to replace an existing shelf registration statement. The universal shelf registration statement allows us to issue additional common units and debt securities. Our 9,000,000 and 12,650,000 common units issued in August 2013 and March 2013, respectively, and 2.50% 5-year Senior Notes were issued under this registration statement.

In March 2012, we issued 5,148,500 common units at $47.42 per unit. We received proceeds of $234 million, net of offering costs.

In March 2012, we issued 1,000,417 common units to DCP Midstream, LLC as partial consideration for the remaining 66.67% interest in Southeast Texas.

In February 2012, we issued 30,701 common units under our 2005 Long-Term Incentive Plan, or 2005 LTIP, to employees as compensation for their service.

In January 2012, we issued 727,520 common units to DCP Midstream, LLC as partial consideration for the remaining 49.9% interest in East Texas.

In August 2011, we entered into an equity distribution agreement with a financial institution, as sales agent. The agreement provides for the offer and sale from time to time, through our sales agent, of common units having an aggregate offering amount of up to $150 million. During the year ended December 31, 2013, we issued 1,408,547 of our common units pursuant to this equity distribution agreement and received proceeds of $67 million, net of commissions and offering costs of $2 million. During the year ended December 31, 2012, we issued 1,147,654 of our common units pursuant to this equity distribution agreement and received proceeds of $47 million, net of commissions and offering costs of $2 million. The proceeds were used to finance growth opportunities and for general partnership purposes. In September 2013, we de-registered the common units that remained unsold under this equity distribution agreement.

Definition of Available Cash — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash, as defined in the partnership agreement, to unitholders of record on the applicable record date, as determined by our general partner. Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by the general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; and
  - provide funds for distributions to the unitholders and to our general partner for any one or more of the next four quarters;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

General Partner Interest and Incentive Distribution Rights - The general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 0.3% and limited partner interest of approximately 1.7% as of December 31, 2014. The 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 incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. The general partner's incentive distribution rights were not reduced as a result of our common unit issuances, and will not be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest. Please read the *Distributions of Available Cash* sections below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

Distributions of Available Cash - Our partnership agreement, after adjustment for the general partner's relative ownership level, requires that we make distributions of Available Cash from operating surplus for any quarter in the following manner:

- *first,* to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter;
- *second,* 13% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter;
- *third,* 23% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter; and
- *thereafter,* 48% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders.

The following table presents our cash distributions paid in 2014, 2013 and 2012:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
November 14, 2014	$ 0.7700	$ 117
August 14, 2014	$ 0.7575	$ 111
May 15, 2014	$ 0.7450	$ 106
February 14, 2014	$ 0.7325	$ 86
November 14, 2013	$ 0.7200	$ 82
August 14, 2013	$ 0.7100	$ 72
May 15, 2013	$ 0.7000	$ 69
February 14, 2013	$ 0.6900	$ 54
November 14, 2012	$ 0.6800	$ 53
August 14, 2012	$ 0.6700	$ 49
May 15, 2012	$ 0.6600	$ 43
February 14, 2012	$ 0.6500	$ 37

14. Equity-Based Compensation

On November 28, 2005, the board of directors of our General Partner adopted a Long-Term Incentive Plan, or the 2005 LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 2005 LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. The 2005 LTIP phantom units consist of a notional unit based on the value of the Partnership's common units. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be issued and delivered pursuant to awards under the 2005 LTIP. Awards that are canceled or forfeited, or are withheld to satisfy the General Partner's tax withholding obligations, are available for delivery pursuant to other awards. On February 15, 2012, the board of directors of our General Partner adopted a 2012 LTIP for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 2012 LTIP provides for the grant of phantom units and DERs. The 2012 LTIP phantom units consist of a notional unit based on the value of common units or shares of Phillips 66 and Spectra Energy. The LTIPs were administered by the compensation committee of the General Partner's board of directors through 2012, and by the General Partner's board of directors beginning in 2013. Awards are issued under both LTIPs and all awards are subject to cliff vesting.

Since we have the intent and ability to settle certain awards within our control in units, we classify them as equity awards based on their fair value. The fair value of our equity awards is determined based on the closing price of our common units at the grant date. Compensation expense on equity awards is recognized ratably over each vesting period. We account for other awards which are subject to settlement in cash, including DERs, as liability awards. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-measured each reporting period for all awards outstanding until the units are vested. The fair value of all liability awards is determined based on the closing price of our common units at each measurement date.

We recognized $1 million in compensation expense related to our LTIP awards for the year ended December 31, 2014 and $2 million for each of the years ended December 31, 2013 and 2012. As of December 31, 2014, we have less than $1 million of unrecognized compensation expense related to LTIP awards.

15. Net Income or Loss per Limited Partner Unit

Our net income or loss is allocated to the general partner and the limited partners in accordance with their respective ownership percentages, after allocating Available Cash generated during the period in accordance with our partnership agreement.

Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

These required disclosures do not impact our overall net income or loss or other financial results; however, in periods in which aggregate net income exceeds our Available Cash it will have the impact of reducing net income per LPU.

Basic and diluted net income or loss per limited partner unit, or LPU, is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding LPUs during the period. Diluted net income or loss per LPU is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Dilutive potential units include outstanding awards under the LTIP. The dilutive effect of unit-based awards was 10,574, 19,179 and 33,034 equivalent units during the years ended December 31, 2014, 2013 and 2012, respectively.

16. Income Taxes

We are structured as a master limited partnership with sufficient qualifying income, which is a pass-through entity for federal income tax purposes. Accordingly, we had no federal income tax expense for the years ended December 31, 2014, 2013 and 2012.

The State of Texas imposes a margin tax that is assessed at 0.95%, 0.975%, and 1% of taxable margin apportioned to Texas for the years ended December 31, 2014, 2013 and 2012.

Income tax expense consists of the following:

	Year Ended December 31,		
	2014	2013	2012
		(Millions)	
Current state income tax expense	$ 3	$ 3	$ 1
Deferred state income tax expense	3	5	—
Total income tax expense	$ 6	$ 8	$ 1

We had net long-term deferred tax liabilities of $13 million and $11 million as of December 31, 2014 and 2013, included in other long-term liabilities on the consolidated balance sheets. These state deferred tax liabilities relate to our Texas operations and are primarily associated with depreciation related to property, plant and equipment.

Our effective tax rate differs from statutory rates, primarily due to being structured as a master limited partnership, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states.

17. Commitments and Contingent Liabilities

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

Insurance - We renewed our insurance policies in May, June, July and August 2014 for the 2014-2015 insurance year. We contract with third party insurers for: (1) automobile liability insurance for all owned, non-owned and hired vehicles; (2) general liability insurance; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) property insurance, which covers replacement value of real and personal property and includes business interruption/extra expense. These renewals have not resulted in any material change to the premiums we are contracted to pay. We are jointly insured with DCP Midstream, LLC for a portion of the insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies that are of similar size to us and with similar types of operations.

The insurance on Discovery, as placed by Williams Field Service Group LLC, for the 2014-2015 insurance year includes general and excess liability, onshore property damage, including named windstorm and business interruption, and offshore non-wind property and business interruption insurance. The availability of offshore named windstorm property and business interruption insurance has been significantly reduced over the past few years, we believe as a result of higher industry-wide damage claims. Additionally, we believe the named windstorm property and business interruption insurance that is available comes at uneconomic premium levels, high deductibles and low coverage limits. As such, Discovery continues to elect not to purchase offshore named windstorm property and business interruption insurance coverage for the 2014-2015 insurance year.

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

Indemnification - DCP Midstream, LLC has indemnified us for certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessors.

Other Commitments and Contingencies - We utilize assets under operating leases in several areas of operation. Consolidated rental expense, including leases with no continuing commitment, totaled $13 million, $17 million, and $14 million for the years ended December 31, 2014, 2013, and 2012, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows at December 31, 2014:

	(Millions)
2015	$ 15
2016	12
2017	11
2018	9
2019	8
Thereafter	26
Total minimum rental payments	$ 81

18. Business Segments

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

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

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

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

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

The following tables set forth our segment information:

Year Ended December 31, 2014:

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 3,163	$ 73	$ 406	$ —	$ 3,642
Gross margin (a)	$ 756	$ 73	$ 18	—	$ 847
Operating and maintenance expense	(189)	(16)	(11)	—	(216)
Depreciation and amortization expense	(101)	(7)	(2)	—	(110)
General and administrative expense	—	—	—	(64)	(64)
Other expense	(2)	(1)	—	—	(3)
Earnings from unconsolidated affiliates	5	70	—	—	75
Interest expense	—	—	—	(86)	(86)
Income tax expense	—	—	—	(6)	(6)
Net income (loss)	$ 469	$ 119	$ 5	$ (156)	$ 437
Net income attributable to noncontrolling interests	(14)	—	—	—	(14)
Net income (loss) attributable to partners	$ 455	$ 119	$ 5	$ (156)	$ 423
Non-cash derivative mark-to-market (b)	$ 89	$ —	$ (3)	$ —	$ 86
Non-cash lower of cost or market adjustments	$ 11	$ —	$ 13	$ —	$ 24
Capital expenditures	$ 297	$ 25	$ 16	$ —	$ 338
Acquisition expenditures	$ 102	$ 673	$ —	$ —	$ 775
Investments in unconsolidated affiliates	$ 75	$ 76	$ —	$ —	$ 151

Year Ended December 31, 2013:

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 2,598	$ 73	$ 380	$ —	$ 3,051
Gross margin (a)	$ 501	$ 72	$ 52	$ —	$ 625
Operating and maintenance expense	(184)	(16)	(15)	—	(215)
Depreciation and amortization expense	(87)	(6)	(2)	—	(95)
General and administrative expense	—	—	—	(63)	(63)
Other expense	(1)	(3)	(4)	—	(8)
Earnings from unconsolidated affiliates	1	32	—	—	33
Interest expense	—	—	—	(52)	(52)
Income tax expense	—	—	—	(8)	(8)
Net income (loss)	$ 230	$ 79	$ 31	$ (123)	$ 217
Net income attributable to noncontrolling interests	(17)	—	—	—	(17)
Net income (loss) attributable to partners	$ 213	$ 79	$ 31	$ (123)	$ 200
Non-cash derivative mark-to-market (b)	$ (36)	$ —	$ (1)	$ 1	$ (36)
Non-cash lower of cost or market adjustments	$ 2	$ —	$ 2	$ —	$ 4
Capital expenditures	$ 334	$ 24	$ 5	$ —	$ 363
Acquisition expenditures	$ 696	$ 86	$ —	$ —	$ 782
Investments in unconsolidated affiliates	$ 133	$ 109	$ —	$ —	$ 242

Year Ended December 31, 2012:

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 2,345	$ 64	$ 415	$ —	$ 2,824
Gross margin (a)	$ 503	$ 64	$ 42	$ —	$ 609
Operating and maintenance expense	(166)	(16)	(15)	—	(197)
Depreciation and amortization expense	(83)	(6)	(2)	—	(91)
General and administrative expense	—	—	—	(75)	(75)
Earnings from unconsolidated affiliates	15	11	—	—	26
Interest expense	—	—	—	(42)	(42)
Income tax expense	—	—	—	(1)	(1)
Net income (loss)	$ 269	$ 53	$ 25	$ (118)	$ 229
Net income attributable to noncontrolling interests	(13)	—	—	—	(13)
Net income (loss) attributable to partners	$ 256	$ 53	$ 25	$ (118)	$ 216
Non-cash derivative mark-to-market (b)	$ 20	$ —	$ 1	$ —	$ 21
Capital expenditures	$ 468	$ 12	$ 4	$ —	$ 484
Acquisitions net of cash acquired	$ 715	$ 30	$ —	$ —	$ 745
Investments in unconsolidated affiliates	$ 115	$ 43	$ —	$ —	$ 158

	December 31, 2014	December 31, 2013
	(Millions)	
Segment long-term assets:		
Natural Gas Services (c)	$ 3,609	$ 3,303
NGL Logistics	1,364	555
Wholesale Propane Logistics	118	106
Other (d)	58	100
Total long-term assets	5,149	4,064
Current assets (c)	590	503
Total assets	$ 5,739	$ 4,567

(a) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs. Gross margin is viewed as a non-GAAP measure under the rules of the SEC, but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.
(b) Non-cash derivative mark-to-market is included in gross margin, along with cash settlements for our commodity derivative contracts.
(c) The segment information as of and for the years ended December 31, 2014, 2013 and 2012 includes the results of our Lucerne 1 plant, an 80% interest in the Eagle Ford system and a 100% interest in Southeast Texas. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information, similar to the pooling method.
(d) Other long-term assets not allocable to segments consist of unrealized gains on derivative instruments, corporate leasehold improvements and other long-term assets.

19. Supplemental Cash Flow Information

	Year Ended December 31, 2014	2013	2012
		(Millions)	
Cash paid for interest:			
Cash paid for interest, net of amounts capitalized	$ 73	$ 40	$ 23
Cash paid for income taxes, net of income tax refunds	$ 2	$ 1	$ 1
Non-cash investing and financing activities:			
Property, plant and equipment acquired with accounts payable	$ 43	$ 27	$ 47
Other non-cash additions of property, plant and equipment	$ 4	$ 1	$ 8
Non-cash addition of investment in unconsolidated affiliates and property, plant and equipment acquired in March 2014 Transactions	$ 65	$ —	$ —
Non-cash excess purchase price in March 2014 Transactions and March 2013 Eagle Ford system transaction	$ 160	$ 125	$ —
Accounts payable related to equity issuance costs	$ —	$ 1	$ —
Non-cash change in parent advances	$ —	$ —	$ (115)

20. Quarterly Financial Data (Unaudited)

Our consolidated results of operations by quarter for the years ended December 31, 2014 and 2013 were as follows (millions, except per unit amounts):

2014	First (a)	Second	Third	Fourth	Year Ended December 31, 2014 (a)
Total operating revenues	$ 1,081	$ 812	$ 868	$ 881	$ 3,642
Operating income	$ 108	$ 37	$ 111	$ 198	$ 454
Net income	$ 89	$ 29	$ 116	$ 203	$ 437
Net income attributable to noncontrolling interests	$ (10)	$ —	$ —	$ (4)	$ (14)
Net income attributable to partners	$ 79	$ 29	$ 116	$ 199	$ 423
Net income allocable to limited partners	$ 47	$ 2	$ 86	$ 168	$ 303
Basic and diluted net income per limited partner unit	$ 0.50	$ 0.02	$ 0.77	$ 1.48	$ 2.84

2013	First (a)(b)	Second (a)	Third (a)	Fourth (a)	Year Ended December 31, 2013 (a)
Total operating revenues	$ 749	$ 792	$ 689	821	3,051
Operating income	$ 65	$ 117	$ 14	48	244
Net income	$ 60	$ 111	$ 6	40	217
Net income attributable to noncontrolling interests	$ (3)	$ (4)	$ (3)	(7)	(17)
Net income attributable to partners	$ 57	$ 107	$ 3	33	200
Net income (loss) allocable to limited partners	$ 31	$ 86	$ (20)	8	105
Basic and diluted net income (loss) per limited partner unit	$ 0.48	$ 1.11	$ (0.24)	0.09	1.34

(a) Our consolidated results of operations have been adjusted to retrospectively include the historical results of the Lucerne 1 plant for the periods presented.
(b) Our consolidated results of operations have been adjusted to retrospectively include the historical results of an 80% interest in the Eagle Ford system for the periods presented.

21. Supplementary Information — Condensed Consolidating Financial Information

The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream Partners, LP, or parent guarantor, DCP Midstream Operating LP, or subsidiary issuer, which is a 100% owned subsidiary, and non-guarantor subsidiaries, as well as the consolidating adjustments necessary to present DCP Midstream Partners, LP's results on a consolidated basis. In conjunction with the universal shelf registration statement on Form S-3 which became effective on June 14, 2012, the parent guarantor has agreed to fully and unconditionally guarantee debt securities of the subsidiary issuer. For the purpose of the following financial information, investments in subsidiaries are reflected in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

Condensed Consolidating Balance Sheet
December 31, 2014

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

	Condensed Consolidating Balance Sheet December 31, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ —	$ 12	$ —	$ 12
Accounts receivable, net	—	—	342	—	342
Inventories	—	—	67	—	67
Other	—	—	82	—	82
Total current assets	—	—	503	—	503
Property, plant and equipment, net	—	—	3,046	—	3,046
Goodwill and intangible assets, net	—	—	283	—	283
Advances receivable — consolidated subsidiaries	1,805	1,683	—	(3,488)	—
Investments in consolidated subsidiaries	181	426	—	(607)	—
Investments in unconsolidated affiliates	—	—	627	—	627
Other long-term assets	—	12	96	—	108
Total assets	$ 1,986	$ 2,121	$ 4,555	$ (4,095)	$ 4,567
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ 1	$ 350	$ 372	$ —	$ 723
Advances payable — consolidated subsidiaries	—	—	3,488	(3,488)	—
Long-term debt	—	1,590	—	—	1,590
Other long-term liabilities	—	—	41	—	41
Total liabilities	1	1,940	3,901	(3,488)	2,354
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Predecessor equity	—	—	40	—	40
Net equity	1,985	187	391	(607)	1,956
Accumulated other comprehensive loss	—	(6)	(5)	—	(11)
Total partners' equity	1,985	181	426	(607)	1,985
Noncontrolling interests	—	—	228	—	228
Total equity	1,985	181	654	(607)	2,213
Total liabilities and equity	$ 1,986	$ 2,121	$ 4,555	$ (4,095)	$ 4,567

(a) The financial information as of December 31, 2013 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Operations Year Ended December 31, 2014 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 3,143	$ —	$ 3,143
Transportation, processing and other	—	—	345	—	345
Gains from commodity derivative activity, net	—	—	154	—	154
Total operating revenues	—	—	3,642	—	3,642
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	2,795	—	2,795
Operating and maintenance expense	—	—	216	—	216
Depreciation and amortization expense	—	—	110	—	110
General and administrative expense	—	—	64	—	64
Other expense	—	—	3	—	3
Total operating costs and expenses	—	—	3,188	—	3,188
Operating income	—	—	454	—	454
Interest expense, net	—	(86)	—	—	(86)
Income from consolidated subsidiaries	423	509	—	(932)	—
Earnings from unconsolidated affiliates	—	—	75	—	75
Income before income taxes	423	423	529	(932)	443
Income tax expense	—	—	(6)	—	(6)
Net income	423	423	523	(932)	437
Net income attributable to noncontrolling interests	—	—	(14)	—	(14)
Net income attributable to partners	$ 423	$ 423	$ 509	$ (932)	$ 423

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

	Condensed Consolidating Statement of Comprehensive Income Year Ended December 31, 2014 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 423	$ 423	$ 523	$ (932)	$ 437
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	2	—	—	2
Other comprehensive income from consolidated subsidiaries	2	—	—	(2)	—
Total other comprehensive income	2	2	—	(2)	2
Total comprehensive income	425	425	523	(934)	439
Total comprehensive income attributable to noncontrolling interests	—	—	(14)	—	(14)
Total comprehensive income attributable to partners	$ 425	$ 425	$ 509	$ (934)	$ 425

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

	Condensed Consolidating Statement of Operations Year Ended December 31, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 2,763	$ —	$ 2,763
Transportation, processing and other	—	—	271	—	271
Gains from commodity derivative activity, net	—	—	17	—	17
Total operating revenues	—	—	3,051	—	3,051
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	2,426	—	2,426
Operating and maintenance expense	—	—	215	—	215
Depreciation and amortization expense	—	—	95	—	95
General and administrative expense	—	—	63	—	63
Other expense	—	—	8	—	8
Total operating costs and expenses	—	—	2,807	—	2,807
Operating income	—	—	244	—	244
Interest expense	—	(52)	—	—	(52)
Earnings from unconsolidated affiliates	—	—	33	—	33
Income from consolidated subsidiaries	200	252	—	(452)	—
Income before income taxes	200	200	277	(452)	225
Income tax expense	—	—	(8)	—	(8)
Net income	200	200	269	(452)	217
Net income attributable to noncontrolling interests	—	—	(17)	—	(17)
Net income attributable to partners	$ 200	$ 200	$ 252	$ (452)	$ 200

(a) The financial information for the year ended December 31, 2013 includes the results of our Lucerne 1 plant and an 80% interest in the Eagle Ford system. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Comprehensive Income Year Ended December 31, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 200	$ 200	$ 269	$ (452)	$ 217
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	4	—	—	4
Other comprehensive income from consolidated subsidiaries	4	—	—	(4)	—
Total other comprehensive income	4	4	—	(4)	4
Total comprehensive income	204	204	269	(456)	221
Total comprehensive income attributable to noncontrolling interests	—	—	(17)	—	(17)
Total comprehensive income attributable to partners	$ 204	$ 204	$ 252	$ (456)	$ 204

(a) The financial information for the year ended December 31, 2013 includes the results of our Lucerne 1 plant and an 80% interest in the Eagle Ford system. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Operations Year Ended December 31, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 2,520	$ —	$ 2,520
Transportation, processing and other	—	—	234	—	234
Gains from commodity derivative activity, net	—	—	70	—	70
Total operating revenues	—	—	2,824	—	2,824
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	2,215	—	2,215
Operating and maintenance expense	—	—	197	—	197
Depreciation and amortization expense	—	—	91	—	91
General and administrative expense	—	—	75	—	75
Total operating costs and expenses	—	—	2,578	—	2,578
Operating income	—	—	246	—	246
Interest expense	—	(41)	(1)	—	(42)
Earnings from unconsolidated affiliates	—	—	26	—	26
Income from consolidated subsidiaries	216	257	—	(473)	—
Income before income taxes	216	216	271	(473)	230
Income tax expense	—	—	(1)	—	(1)
Net income	216	216	270	(473)	229
Net income attributable to noncontrolling interests	—	—	(13)	—	(13)
Net income attributable to partners	$ 216	$ 216	$ 257	$ (473)	$ 216

(a) The financial information for the year ended December 31, 2012 includes the results of our Lucerne 1 plant, an 80% interest in the Eagle Ford system and our 100% interest in Southeast Texas and commodity derivative hedge instruments related to the Southeast Texas storage business. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Comprehensive Income Year Ended December 31, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 216	$ 216	$ 270	$ (473)	$ 229
Other comprehensive income (loss):					
Reclassification of cash flow hedge losses into earnings	—	10	—	—	10
Net unrealized losses on cash flow hedges	—	(1)	—	—	(1)
Other comprehensive income from consolidated subsidiaries	9	—	—	(9)	—
Total other comprehensive income	9	9	—	(9)	9
Total comprehensive income	225	225	270	(482)	238
Total comprehensive income attributable to noncontrolling interests	—	—	(13)	—	(13)
Total comprehensive income attributable to partners	$ 225	$ 225	$ 257	$ (482)	$ 225

(a) The financial information for the year ended December 31, 2012 includes the results of our Lucerne 1 plant, an 80% interest in the Eagle Ford system and our 100% interest in Southeast Texas and commodity derivative hedge instruments related to the Southeast Texas storage business. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Cash Flows Year Ended December 31, 2014 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	—	(73)	597	—	524
INVESTING ACTIVITIES:					
Intercompany transfers	(581)	(280)	—	861	—
Capital expenditures	—	—	(338)	—	(338)
Acquisitions, net of cash acquired	—	—	(102)	—	(102)
Acquisition of unconsolidated affiliates	—	—	(673)	—	(673)
Investments in unconsolidated affiliates	—	—	(151)	—	(151)
Proceeds from sales of assets	—	—	28	—	28
Net cash used in investing activities	(581)	(280)	(1,236)	861	(1,236)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	861	(861)	—
Proceeds from long-term debt	—	719	—	—	719
Payments of commercial paper, net	—	(335)	—	—	(335)
Payments of deferred financing costs	—	(7)	—	—	(7)
Excess purchase price over acquired interests and commodity hedges	—	—	(18)	—	(18)
Proceeds from issuance of common units, net of offering costs	1,001	—	—	—	1,001
Net change in advances to predecessor from DCP Midstream, LLC	—	—	(6)	—	(6)
Distributions to limited partners and general partner	(420)	—	—	—	(420)
Distributions to noncontrolling interests	—	—	(14)	—	(14)
Purchase of additional interest in a subsidiary	—	—	(198)	—	(198)
Contributions from noncontrolling interests	—	—	3	—	3
Net cash provided by financing activities	581	377	628	(861)	725
Net change in cash and cash equivalents	—	24	(11)	—	13
Cash and cash equivalents, beginning of period	—	—	12	—	12
Cash and cash equivalents, end of period	—	24	1	—	25

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

	Condensed Consolidating Statements of Cash Flows Year Ended December 31, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (45)	$ 387	$ 3	$ 345
INVESTING ACTIVITIES:					
Intercompany transfers	(806)	(258)	—	1,064	—
Capital expenditures	—	—	(363)	—	(363)
Acquisitions, net of cash acquired	—	—	(696)	—	(696)
Investments in unconsolidated affiliates	—	—	(242)	—	(242)
Acquisition of unconsolidated affiliates	—	—	(86)	—	(86)
Net cash used in investing activities	(806)	(258)	(1,387)	1,064	(1,387)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	1,064	(1,064)	—
Proceeds from long-term debt	—	1,957	—	—	1,957
Payments of long-term debt	—	(1,988)	—	—	(1,988)
Proceeds from issuance of commercial paper	—	335	—	—	335
Payment of deferred financing costs	—	(4)	—	—	(4)
Proceeds from issuance of common units, net of offering costs	1,083	—	—	—	1,083
Excess purchase price over acquired interests and commodity hedges	—	—	(85)	—	(85)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	11	—	11
Distributions to limited partners and general partner	(277)	—	—	—	(277)
Distributions to noncontrolling interests	—	—	(24)	—	(24)
Contributions from noncontrolling interests	—	—	46	—	46
Distributions to DCP Midstream, LLC	—	—	(3)	—	(3)
Contributions from DCP Midstream, LLC	—	—	1	—	1
Net cash provided by financing activities	806	300	1,010	(1,064)	1,052
Net change in cash and cash equivalents	—	(3)	10	3	10
Cash and cash equivalents, beginning of period	—	3	2	(3)	2
Cash and cash equivalents, end of period	$ —	$ —	$ 12	$ —	$ 12

(a) The financial information during the year ended December 31, 2013 includes the results of our Lucerne 1 plant and an 80% interest in the Eagle Ford system. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statements of Cash Flows Year Ended December 31, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (39)	$ 142	$ (1)	$ 102
INVESTING ACTIVITIES:					
Intercompany transfers	(274)	(827)	—	1,101	—
Capital expenditures	—	—	(484)	—	(484)
Acquisitions, net of cash acquired	—	—	(745)	—	(745)
Investments in unconsolidated affiliates	—	—	(158)	—	(158)
Return of investment from unconsolidated affiliate	—	—	1	—	1
Proceeds from sale of assets	—	—	2	—	2
Net cash used in investing activities	(274)	(827)	(1,384)	1,101	(1,384)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	1,101	(1,101)	—
Proceeds from long-term debt	—	2,665	—	—	2,665
Payments of long-term debt	—	(1,792)	—	—	(1,792)
Payment of deferred financing costs	—	(8)	—	—	(8)
Proceeds from issuance of common units, net of offering costs	455	—	—	—	455
Excess purchase price over acquired assets	—	—	(225)	—	(225)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	336	—	336
Distributions to common unitholders and general partner	(181)	—	—	—	(181)
Distributions to noncontrolling interests	—	—	(9)	—	(9)
Contributions from noncontrolling interests	—	—	25	—	25
Contributions from DCP Midstream, LLC	—	—	10	—	10
Net cash provided by financing activities	274	865	1,238	(1,101)	1,276
Net change in cash and cash equivalents	—	(1)	(4)	(1)	(6)
Cash and cash equivalents, beginning of year	—	4	6	(2)	8
Cash and cash equivalents, end of year	$ —	$ 3	$ 2	$ (3)	$ 2

(a) The financial information during the year ended December 31, 2012 includes the results of our Lucerne 1 plant, our 80% interest in the Eagle Ford system and our 100% interest in Southeast Texas and commodity derivative hedge instruments related to the Southeast Texas storage business. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

22. Valuation and Qualifying Accounts and Reserves

Our valuation and qualifying accounts and reserves for the years ended December 31, 2014, 2013, and 2012 are as follows:

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Charged to Other Accounts	Deductions/ Other	Balance at End of Period
			(Millions)		
December 31, 2014					
Environmental	$ 2	$ 1	$ —	$ (1)	$ 2
Other (a)	1	—	—	—	1
	$ 3	$ 1	$ —	$ (1)	$ 3
December 31, 2013					
Environmental	$ 2	$ 1	$ —	$ (1)	$ 2
Other (a)	1	—	—	—	1
	$ 3	$ 1	$ —	$ (1)	$ 3
December 31, 2012					
Environmental	$ 3	$ —	$ —	$ (1)	$ 2
Other (a)	1	—	—	—	1
	$ 4	$ —	$ —	$ (1)	$ 3

(a) Principally consists of allowance for doubtful accounts, reserves against other long-term assets, which are included in other long-term assets, and other contingency liabilities, which are included in other current liabilities.

23. Subsequent Events

On January 29, 2015, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.78 per unit. The distribution was paid on February 13, 2015 to unitholders of record on February 9, 2015.

In January 2015, we entered into an agreement with an affiliate of Enterprise Products Partners L.P., or Enterprise, to acquire a 15% ownership interest in Panola Pipeline Company, LLC, or Panola. The anticipated total consideration of approximately $26 million includes our proportionate share in construction costs for an anticipated expansion of the existing Panola NGL pipeline. Originating near Carthage, Texas, the 10-inch diameter expansion will extend approximately 60 miles to Lufkin, Texas and will have an initial capacity of approximately 50 MBbls/d, with expansion to 100 MBbls/d possible following installation of additional pump stations. We, WGR Asset Holding Company LLC, which is an affiliate of Anadarko Petroleum Corporation, and MarkWest Panola Pipeline L.L.C. will each own a 15% interest in Panola. Enterprise will own a 55% interest in Panola and will construct and operate the expansion, which is expected to be in service in the first quarter of 2016.

On February 10, 2015, we, along with Williams Partners L.P., announced that the new extended Discovery natural gas gathering pipeline system is now flowing natural gas. The Keathley Canyon Connector, a 20-inch diameter, 209-mile subsea natural gas gathering pipeline is capable of gathering more than 400 MMcf/d of natural gas, and originates in the southeast portion of the Keathley Canyon protraction area of the Gulf of Mexico, and terminates into Discovery's 30-inch diameter mainline near South Timbalier Block 283.

Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, we no longer have access to the Commercial Paper Program. Our available liquidity under the Commercial Paper Program will be replaced with borrowings under our Amended and Restated Credit Agreement. Additionally, as a result of this ratings action, interest rates and fees under our Amended and Restated Credit Agreement have increased.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

There were no changes in or disagreements with accountants on accounting and financial disclosures during the year ended December 31, 2014.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the Commission's rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner's principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of December 31, 2014, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of December 31, 2014, our disclosure controls and procedures were effective at a reasonable assurance level. There were no changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report On Internal Control Over Financial Reporting

Our general partner is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance to our management and board of directors of our general partner regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, internal control over financial reporting may not prevent or detect misstatements. 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 policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014 based on the 2013 framework in "Internal Control-Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2014.

Deloitte & Touche, LLP, an independent registered public accounting firm, has issued their report, included immediately following, regarding our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
DCP Midstream GP, LLC
Denver, Colorado

We have audited the internal control over financial reporting of DCP Midstream Partners, LP and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible 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 Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2014 of the Company and our report dated February 25, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 25, 2015

Item 9B. ***Other Information***

Amendment to Services Agreement

On February 23, 2015, we entered into the Third Amendment, or the Amendment, to the previously disclosed Services Agreement, dated February 14, 2013, or, as so amended, the Services Agreement, by and between us and DCP Midstream, LP, or Midstream LP. The Amendment increases the annual limit on the amount of expenses that we reimburse to Midstream LP by approximately $25 million to $71 million for general and administrative services that Midstream LP will provide to us during calendar year 2015, thereafter subject to an annual increase based on the Consumer Price Index. Our growth, both from organic growth and acquisitions, has resulted in us becoming a much larger portion of the business of DCP Midstream, LLC, the owner of Midstream LP and the sole member of our General Partner, over the past few years. Additionally, our expansion into downstream logistics has required DCP Midstream, LLC to expand its capabilities and provide us with a broader range of services than what was previously provided. As a result, DCP Midstream, LLC initiated a comprehensive review of its costs and the methodology for allocating general and administrative services. The result of this review reflects the level and cost of general and administrative services provided to us by DCP Midstream, LLC as the operator of our assets.

The Amendment was approved by the special committee of the board of directors of our General Partner, which is comprised of independent directors and acts as our conflicts committee, as required by our partnership agreement and the terms of the Services Agreement.

The foregoing description of the Amendment is not complete and is qualified in its entirety by reference to the full and complete terms of the Amendment, a copy of which is attached to this Annual Report on Form 10-K as Exhibit 10.15 and incorporated herein by reference.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Management of DCP Midstream Partners, LP

We do not have directors or officers, which is commonly the case with publicly traded partnerships. Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as our General Partner. Our General Partner is 100% owned by DCP Midstream, LLC. The officers and directors of our General Partner are responsible for managing us. All of the directors of our General Partner are elected annually by DCP Midstream, LLC and all of the officers of our General Partner serve at the discretion of the directors. Unitholders are not entitled to elect the directors of our General Partner or participate, directly or indirectly, in our management or operations.

Board of Directors and Executive Officers of DCP Midstream GP, LLC

The board of directors of our General Partner currently has ten members, four of whom are independent as defined under the independence standards established by the NYSE. Because we are a listed limited partnership and a controlled company, we are not required by the NYSE rules to have a majority of independent directors on the board of directors of our General Partner or to establish a compensation committee or a nominating/corporate governance committee. However, the board of directors of our General Partner has established an audit committee consisting of four independent members of the board and a special committee to address conflict situations.

Our General Partner’s board of directors annually reviews the independence of directors and affirmatively makes a determination that each director expected to be independent has no material relationship with our General Partner, either directly or indirectly as a partner, unitholder or officer of an organization that has a relationship with our General Partner. Our General Partner’s board of directors has affirmatively determined that Messrs. Ferguson, McPherson, Morris, and Springer satisfy the SEC and NYSE independence standards.

The executive officers of our General Partner are responsible for establishing and executing strategic business and operation plans and managing the day-to-day affairs of our business. Certain of these executive officers allocate their time between managing our business and affairs and the business and affairs of DCP Midstream, LLC. We expect that the amount of time these certain executive officers devote to our business may increase or decrease in future periods driven by the needs and demands of our ongoing business and business development efforts. All of our executive management personnel are employees of DCP Midstream, LLC. We also utilize employees of DCP Midstream, LLC to operate our business and provide us with general and administrative services that are reimbursed to DCP Midstream, LLC under the Services Agreement.

The following table shows information regarding the current directors and the executive officers of DCP Midstream GP, LLC. Directors are appointed annually by DCP Midstream, LLC and hold office for one year or until their successors have been elected and qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board of directors. There are no family relationships among any of the directors or executive officers.

Name	Age	Position with DCP Midstream GP, LLC
Wouter T. van Kempen	45	Chief Executive Officer, Chairman of the Board and Director
William S. Waldheim	58	President and Director
Sean P. O'Brien	45	Group Vice President and Chief Financial Officer
Michael S. Richards	55	Vice President, General Counsel and Secretary
Guy Buckley	54	Director
Paul F. Ferguson, Jr.	65	Director
R. Mark Fiedorek	52	Director
Frank A. McPherson	81	Director
Thomas C. Morris	74	Director
Stephen R. Springer	68	Director
Andy Viens	60	Director
Brian R. Wenzel	50	Director

Wouter T. van Kempen was elected Chairman and member of the Board of DCP Midstream GP, LLC on January 1, 2014 and CEO of DCP Midstream GP, LLC on January 1, 2013. Mr. van Kempen is also the Chairman, President and Chief Executive Officer for DCP Midstream, LLC, the owner of our General Partner, since January 1, 2013. Mr. van Kempen was previously the President and Chief Operating Officer of DCP Midstream, LLC from September 2012 until January 1, 2013. Prior to that time, Mr. van Kempen was President, Gathering and Processing, of DCP Midstream, LLC from January 2012 to August 2012; President, Midcontinent & Permian Business Units, and Chief Development Officer from June 2011 to December 2011; and President, Midcontinent, and Chief Development Officer from August 2010 to May 2011. Prior to joining DCP Midstream, LLC in 2010, Mr. van Kempen was President of Duke Energy Generation Services from September 2006 to July 2010 and Vice President of Mergers and Acquisitions from December 2005 to September 2006. Mr. van Kempen joined Duke Energy in 2003 and served in a number of management positions. Prior to Duke Energy, Mr. van Kempen was employed by General Electric, where he served in increasing roles of responsibility becoming the staff executive for corporate mergers and acquisitions in 1999. Mr. van Kempen graduated from Erasmus University Rotterdam with a master's degree in business economics. He has extensive business and financial training from General Electric, Harvard Business School, Kellogg Graduate School and IMD International Switzerland.

William S. Waldheim was elected President of DCP Midstream GP, LLC in September 2012 and was elected as a director in January 2013. Prior to that time, Mr. Waldheim was President, NGL, of DCP Midstream, LLC and served in that position since 2011. Prior to that time, Mr. Waldheim was President of DCP Midstream, LLC's northern business unit since 2009 where he was responsible for executive management of commercial and operations of the assets in the Midcontinent, Rocky Mountain, Michigan and Gulf Coast regions as well as the downstream marketing of gas, NGLs and condensate. From 1999 to 2009, Mr. Waldheim served in a variety of commercial and operational executive management positions at DCP Midstream, LLC. Prior to joining DCP Midstream, Mr. Waldheim served in a number of executive management positions with Union Pacific Fuels, Inc. Mr. Waldheim has over 30 years of experience in the energy industry and has previously served on the boards of various energy industry groups including the National Propane Gas Association and the Propane Education & Research Council. Mr. Waldheim currently serves on the board of directors of the Colorado Oil & Gas Association and the Rocky Mountain Chapter of Junior Achievement.

Sean P. O'Brien was appointed Group Vice President and Chief Financial Officer of DCP Midstream GP, LLC in January 2014. Mr. O'Brien is also the Group Vice President and Chief Financial Officer for DCP Midstream, LLC and has served in that position since May 2012. Prior to that time, Mr. O'Brien was Senior Vice President and Treasurer of DCP Midstream, LLC from May 2011 and prior to that, he served as Vice President, Financial Planning and Analysis from September 2009. Prior to joining DCP Midstream, LLC in September 2009, Mr. O'Brien was with Duke Energy Corporation where he served as General Manager of Financial Planning and Forecasting for Duke Energy's Commercial Business Unit from May 2006, and prior to that, he was Vice President and Controller of Duke Energy Generation Services from May 2005. Mr. O'Brien joined Duke Energy in 1997. Mr. O'Brien is a certified public accountant with over 21 years of experience in the finance area and over 16 years of experience in the energy industry.

Michael S. Richards was elected Vice President, General Counsel and Secretary of DCP Midstream GP, LLC in September 2005. Mr. Richards was previously Assistant General Counsel and Assistant Secretary of DCP Midstream, LLC since February 2000. He was previously Assistant General Counsel and Assistant Secretary at KN Energy, Inc. from December 1997 until he joined DCP Midstream, LLC. Prior to that, he was Senior Counsel and Risk Manager at Total Petroleum (North America) Ltd. from 1994 through 1997. Mr. Richards was previously in private practice where he focused on securities and corporate finance. Mr. Richards has also been Vice President and Deputy General Counsel for DCP Midstream, LLC since 2013.

Guy Buckley was elected as a director of DCP Midstream, GP, LLC in October 2014. Mr. Buckley is currently Chief Development Officer of Spectra Energy. Prior to assuming his current role in January 2014, Mr. Buckley served as Spectra Energy's Treasurer and Group Vice President, Mergers and Acquisitions from January 2012 to December 2013, and as Group Vice President, Corporate Strategy and Development from December 2008 to December 2011. Since joining Spectra in 1989, Mr. Buckley has held a number of leadership positions in the areas of engineering, operations, marketing, and project and business development.

Paul F. Ferguson, Jr. was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Ferguson currently serves as Chairman of the Audit Committee of the board of directors. He served as Senior Vice President and Treasurer of Duke Energy from June 1997 to June 1998, when he retired. Mr. Ferguson served as Senior Vice President and Chief Financial Officer of PanEnergy Corp. from September 1995 to June 1997. He held various other financial positions with PanEnergy Corp. from 1989 to 1995 and served as Treasurer of Texas Eastern Corporation from 1988 to 1989. Mr. Ferguson was a director of the general partner of TEPPCO Partners, L.P. where he was a member of the compensation, audit and special committees from October 2004 until his resignation in 2005.

R. Mark Fiedorek was elected as a director of DCP Midstream GP, LLC in May 2012. Mr. Fiedorek is currently the President of Spectra Energy Transmission's western Canadian operations, a position he has been in since January 2013. Mr. Fiedorek joined Spectra Energy in 1988 and has served in a number of management positions in gas supply, operations, marketing and business development.

Frank A. McPherson was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. McPherson retired as Chairman and Chief Executive Officer from Kerr McGee Corporation in 1997 after a 40-year career with the company. Mr. McPherson was Chairman and Chief Executive Officer of Kerr McGee from 1983 to 1997. Prior to that, he served in various capacities in management of Kerr McGee. Mr. McPherson joined Kerr McGee in 1957. Mr. McPherson served on the boards of Tri Continental Corporation, Seligman Group of Mutual Funds, ConocoPhillips, Kimberly Clark Corporation, MAPCO Inc., Bank of Oklahoma, the Federal Reserve Bank of Kansas City and the American Petroleum Institute. He also served on the boards of several non-profit organizations in Oklahoma.

Thomas C. Morris was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. Morris is currently retired, having served 34 years with Phillips Petroleum Company. Mr. Morris served in various capacities with Phillips, including Vice President and Treasurer and subsequently Senior Vice President and Chief Financial Officer from 1994 until his retirement in 2001. Mr. Morris served as Vice Chairman of the board of OK Mozart, is a former member of the executive board of the American Petroleum Institute finance committee and a former member of the Business Development Council of Texas A&M University.

Stephen R. Springer was elected as a director of DCP Midstream GP, LLC in July 2007. Mr. Springer currently serves as chairman of the Special Committee of the board of Directors which addresses conflict situations. He began his career at Texas Gas Transmission Corporation, where he served in a variety of executive management positions within gas acquisitions and gas marketing. After serving as President of Transco Gas Marketing Company, he served as Vice President of Business Development at Williams Field Services Company and then Senior Vice President and General Manager of Williams Midstream Division, the position he held until his retirement in 2002. Mr. Springer has served on the board of directors of Atmos Energy Corporation (NYSE: ATO) since 2005 and on the board of directors of the Indiana University Foundation.

Andy Viens was elected as a director of DCP Midstream GP, LLC in July 2012. Mr. Viens is currently the President of Global Marketing for Phillips 66. Prior to being named to his current role, Mr. Viens served as President of Global Marketing for ConocoPhillips since 2010. Prior to that time, Mr. Viens served in a variety of capacities at ConocoPhillips including as President, U.S. Marketing and General Manager, Commercial Marine. Prior to joining ConocoPhillips, he was with Tosco where he served in various marketing roles.

Brian R. Wenzel was elected as a director of DCP Midstream GP, LLC in June 2013. Mr. Wenzel is currently the Vice President and Treasurer for Phillips 66. Prior to being named to his current role in May 2012, Mr. Wenzel worked for ConocoPhillips as General Manager, Corporate Planning & Strategy, since July 2010. Prior to that, Mr. Wenzel was Vice President, Finance for ConocoPhillips Alaska, after serving as President, ANS Gas Development, until May 2009. His first position with ConocoPhillips Alaska was in 2005 as Vice President, Finance and Administration. In 2003, Mr. Wenzel was named Manager of Treasury Services of ConocoPhillips in Bartlesville, Oklahoma. In 2001, Mr. Wenzel became the finance manager for Phillips Petroleum Company's Australasia division in Perth, Australia. Mr. Wenzel joined Phillips Petroleum Company in 1991 as a financial analyst.

Director Experience and Qualifications

DCP Midstream, LLC evaluates and recommends candidates for membership on the board of directors of our General Partner based on established criteria. When evaluating director candidates, nominees and incumbent directors, DCP Midstream, LLC has informed us that it considers, among other things, educational background, knowledge of our business and industry, professional reputation, independence, and ability to represent the best interests of our unitholders. DCP Midstream, LLC and the board of directors of our General Partner believe that the above-mentioned attributes, along with the leadership skills and experience in the midstream natural gas industry, provide the Partnership with a capable and knowledgeable board of directors.

Wouter T. van Kempen - We believe Mr. van Kempen is a suitable member of the board of directors as he possesses extensive knowledge and experience about our assets as Chairman and Chief Executive Officer of DCP Midstream GP, LLC and as Chairman, President and Chief Executive Officer of DCP Midstream, LLC and he brings strong management experience having served in positions of increasing responsibility at Duke Energy and General Electric.

Guy Buckley - We believe that Mr. Buckley is a suitable member of the board of directors because of his strong industry experience. Mr. Buckley brings to the Partnership a valuable understanding of transactional, operational and financial matters through his years of service as Chief Development Officer of Spectra Energy and other senior leadership roles in areas that include mergers and acquisitions, corporate strategy and development, and project and business development.

Paul F. Ferguson, Jr. - We believe that Mr. Ferguson is a suitable member of the board of directors because of his extensive industry experience. Mr. Ferguson has held various financial positions with PanEnergy Corp., and the knowledge of industry accounting and financial practices he gained through such experience, coupled with his accounting background and his CPA designation, make him valuable to the board of directors' understanding of the Partnership's financial data and its implications to the future strategic planning of the Partnership. Mr. Ferguson also provides insight to the board of directors as to the Partnership's financial compliance and reporting obligations. Because Mr. Ferguson has served as a director since 2005, he brings to the board of directors valuable historical perspective of board and company operations.

R. Mark Fiedorek - We believe that Mr. Fiedorek is a suitable member of the board of directors because of his extensive industry experience and executive management experience including his positions with Spectra Energy in natural gas transmission, and in the supply, operations and marketing of natural gas.

Frank A. McPherson - We believe that Mr. McPherson is a suitable member of the board of directors because of his extensive industry and executive management experience, spanning over a period of 50 years. In addition, Mr. McPherson's prior public company board experience provides the board of directors with valuable insight into corporate governance and compliance matters. Because Mr. McPherson has served as a director since 2005, he also brings to the board of directors valuable historical perspective of board and company operations.

Thomas C. Morris - We believe that Mr. Morris is a suitable member of the board of directors because of the industry knowledge and experience gained during his 34 years of service with Phillips Petroleum Company. In addition, Mr. Morris' background in finance and accounting, coupled with his previous role as Chief Financial Officer of Phillips Petroleum Company, are invaluable to the board of directors' understanding of the Partnership's financial data and its implications to the future strategic planning of the Partnership. Because Mr. Morris has served as a director since 2005, he also brings to the board of directors valuable historical perspective of board and company operations.

Stephen R. Springer - We believe that Mr. Springer is a suitable member of the board of directors because of his extensive industry experience, including natural gas acquisitions, natural gas marketing, natural gas gathering and processing, NGL transportation and business development. In addition, Mr. Springer's prior public company board experience provides the board of directors with valuable insight into public company operations, corporate governance and compliance matters.

Andy Viens - We believe that Mr. Viens is a suitable member of the board of directors because of his extensive industry experience and executive management experience including his marketing positions at Phillips 66 and ConocoPhillips.

William S. Waldheim - We believe Mr. Waldheim is a suitable member of the board of directors because of his extensive industry experience and his extensive knowledge about and experience with our assets as President of DCP Midstream GP, LLC and in his prior management experience with DCP Midstream, LLC.

Brian R. Wenzel - We believe that Mr. Wenzel is a suitable member of the board of directors because of his extensive industry experience, his knowledge of industry financing as Vice President and Treasurer for Phillips 66 and his significant treasury and finance experience with ConocoPhillips.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires DCP Midstream GP, LLC's directors, executive officers, and persons who own more than 10% of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of our common units and our other equity securities and to furnish us with copies of such reports. To our knowledge, based solely on a review of the copies of reports and amendments thereto furnished to us and written representations that no other reports were required, all Section 16(a) filing requirements applicable to such reporting persons were complied with on a timely basis during the fiscal year ended December 31, 2014.

Audit Committee

The board of directors of our General Partner has a standing audit committee. The audit committee is composed of four independent directors, Paul F. Ferguson, Jr. (chairman), Frank A. McPherson, Thomas C. Morris and Stephen R. Springer, each of whom is able to understand fundamental financial statements and at least one of whom has past experience in accounting or related financial management experience. The board has determined that each member of the audit committee is independent under Section 303A.02 of the NYSE listing standards and Section 10A(m)(3) of the Securities Exchange Act of 1934, as amended. In making the independence determination, the board considered the requirements of the NYSE and our Corporate Governance Guidelines. Among other factors, the board considered current or previous employment with us, our auditors or their affiliates by the director or his immediate family members, ownership of our voting securities, and other material relationships with us. The audit committee has adopted a charter, which has been ratified and approved by the board of directors.

With respect to material relationships, the following relationships are not considered to be material for purposes of assessing independence: service as an officer, director, employee or trustee of, or greater than five percent beneficial ownership in (a) a supplier to the Partnership if the annual sales to the Partnership are less than one percent of the sales of the supplier; (b) a lender to the Partnership if the total amount of the Partnership's indebtedness is less than one percent of the total consolidated assets of the lender; or (c) a charitable organization if the total amount of the Partnership's annual charitable contributions to the organization are less than three percent of that organization's annual charitable receipts.

Mr. Ferguson has been designated by the board as the audit committee's financial expert meeting the requirements promulgated by the SEC and set forth in Item 407(d) of Regulation S-K of the Securities Exchange Act of 1934, as amended, based upon his education and employment experience as more fully detailed in Mr. Ferguson's biography set forth above.

Special Committee

The board of directors of our General Partner has a standing special committee, which is comprised of four independent directors, Stephen R. Springer (chairman), Paul F. Ferguson, Jr., Frank A. McPherson and Thomas C. Morris. The special committee will review specific matters that the board believes may involve conflicts of interest. The special committee will determine if the resolution of the conflict of interest is fair and reasonable to us, or on grounds no less favorable to us than generally available from unrelated third parties. The special committee meets at each quarterly meeting of the board of directors. The members of the special committee may not be officers or employees of our General Partner or directors, officers or employees of its affiliates. Each of the members of the special committee meet the independence and experience standards established by the NYSE and the Securities Exchange Act of 1934, as amended. Any matters approved by the special committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our General Partner of any duties it may owe us or our unitholders.

Corporate Governance Guidelines, Code of Business Ethics, and Audit Committee Charter

Our board of directors has adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance.

We have adopted a Code of Business Ethics applicable to the persons serving as our directors, officers (including without limitation, the chief executive officer, chief financial officer and principal accounting officer) and employees. We intend to disclose any amendment to or waiver of our Code of Business Ethics that applies to our executive officers or directors on our website at *www.dcppartners.com* in order to satisfy disclosure requirements under SEC and NYSE rules relating to such information.

Copies of our Corporate Governance Guidelines, Code of Business Ethics and Audit Committee Charter are available on our website at *www.dcppartners.com*. Copies of these items are also available free of charge in print to any person who sends a request to the office of the Secretary of DCP Midstream Partners, LP at 370 17th Street, Suite 2500, Denver, Colorado 80202. The information contained on, or connected to, our website is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Meeting Attendance and Preparation

During 2014, our board of directors met eleven times and members of the board of directors attended at least 75% of regular and special meetings and meetings of the committees on which they serve, either in person or telephonically. In addition, directors are expected to be prepared for each meeting of the board by reviewing materials distributed in advance.

Meeting of Non-Management Directors and Communications with Directors

At each quarterly meeting of the board of directors, all of our independent directors meet in an executive session without management participation or participation by non-independent directors. The chairman of the special committee, Stephen R. Springer, presides over these executive sessions. In addition, at each quarterly meeting of the board of directors, the non-management members of the board meet in executive session. The chairman of the board of directors has historically presided over these executive sessions, however, with Wouter T. van Kempen's appointment as chairman of the board, Andy Viens will preside over these executive sessions since Mr. van Kempen is a member of management.

Unitholders or interested parties may communicate with any and all members of our board, including our non-management directors, or any committee of our board, by transmitting correspondence by mail or facsimile addressed to one or more directors by name or to the chairman of the board or any committee of the board at the following address and fax number: Name of the Director(s), c/o Secretary, DCP Midstream Partners, LP, 370 17th Street, Suite 2500, Denver, Colorado 80202, fax number (303) 633-2921.

Report of the Audit Committee

The audit committee oversees our financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls. The audit committee operates under a written charter approved by the board of directors. The charter, among other things, provides that the audit committee has authority to appoint, retain and oversee the independent auditor. In this context, the audit committee:

- reviewed and discussed the audited financial statements in this annual report on Form 10-K with management, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements;

- reviewed with Deloitte & Touche, LLP, our independent auditors, who are responsible for expressing an opinion on the conformity of those audited financial statements with generally accepted accounting principles, their judgments as to the quality and acceptability of our accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards;

- received the written disclosures and the letter required by standard No. 1 of the independence standards board (independence discussions with audit committees) provided to the audit committee by Deloitte & Touche, LLP;

- discussed with Deloitte & Touche, LLP its independence from management and us and considered the compatibility of the provision of nonaudit service by the independent auditors with the auditors' independence;

- discussed with Deloitte & Touche, LLP the matters required to be discussed by statement on auditing standards No. 16 (PCAOB Auditing Standard No. 16, Communications With Audit Committees, Related Amendments to PCAOB Standards and Transitional Amendments to AU Section 380);

- discussed with our internal auditors and Deloitte & Touche, LLP the overall scope and plans for their respective audits. The audit committee meets with the internal auditors and Deloitte & Touche, LLP, with and without management present, to discuss the results of their examinations, their evaluations of our internal controls and the overall quality of our financial reporting;

- based on the foregoing reviews and discussions, recommended to the board of directors that the audited financial statements be included in the annual report on Form 10-K for the year ended December 31, 2014, for filing with the Securities and Exchange Commission; and

- approved the selection and appointment of Deloitte & Touche, LLP to serve as our independent auditors.

This report has been furnished by the members of the audit committee of the board of directors:

Audit Committee
Paul F. Ferguson, Jr. (Chairman)
Frank A. McPherson
Thomas C. Morris
Stephen R. Springer

The report of the audit committee in this report shall not be deemed incorporated by reference into any other filing by DCP Midstream Partners, LP under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under such acts.

Item 11. *Executive Compensation*

Compensation Discussion and Analysis

General

As a publicly traded limited partnership, we do not have directors, officers or employees. Instead, our operations are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as our General Partner. Our General Partner is 100% owned by DCP Midstream, LLC.

For the year ended December 31, 2014, the named executive officers, or NEOs, for our General Partner were Wouter T. van Kempen, CEO (Principal Executive Officer), William S. Waldheim, President, Sean P. O'Brien, Group Vice President and CFO (Principal Financial Officer), Rose M. Robeson, former Senior Vice President and CFO (former Principal Financial Officer), and Michael S. Richards, Vice President, General Counsel and Secretary. Certain of these NEOs allocate their time between managing our business and affairs and the business and affairs of DCP Midstream, LLC as indicated in the table below. We expect that the amount of time these certain NEOs devote to our business may increase or decrease in future periods driven by the needs and demands of our ongoing business.

The following table presents the estimated percentage of time ("time allocation") that the General Partner's NEOs devoted to the Partnership during the year ended December 31, 2014:

NEO	Time Devoted to the Partnership	Position with DCP Midstream GP, LLC	Position with DCP Midstream, LLC
Wouter T. van Kempen	25%	Chairman of the Board and Chief Executive Officer	Chairman of the Board, President, and Chief Executive Officer
William S. Waldheim	100%	President	Group Vice President, DCP Midstream Partners
Sean P. O'Brien	25%	Group Vice President and Chief Financial Officer	Group Vice President and Chief Financial Officer
Rose M. Robeson	100%	Former Senior Vice President and Chief Financial Officer	N/A
Michael S. Richards	90%	Vice President, General Counsel and Secretary	Vice President and Deputy General Counsel

The General Partner has not entered into employment agreements with any of the NEOs. The reimbursement for compensation of NEOs devoting less than a majority of their time to our operations and management is based on the percentage of time allocated to us during a period and is included in the fixed general and administrative fee that we pay to DCP Midstream, LLC pursuant to the terms of the Services Agreement. Each of Messrs. van Kempen and O'Brien devoted approximately 25% of his time to our business in 2014. Messrs. van Kempen and O'Brien do not receive any separate amounts of compensation for their services to our business or as executive officers of our General Partner and we do not pay any compensation amounts to Messrs. van Kempen and O'Brien except for amounts directly reimbursed through the general and administrative fee that we pay to DCP Midstream, LLC pursuant to the terms of the Services Agreement. In 2014, the fixed general and administrative fee we paid to DCP Midstream, LLC included an aggregate of $700,000 as reimbursement for the time allocated to our business by Messrs. van Kempen and O'Brien.

Each of Messrs. van Kempen and O'Brien expects to devote approximately 40% of his time to our matters in 2015. We will reimburse DCP Midstream, LLC for that portion of time pursuant to the Services Agreement, which we expect to be an aggregate of approximately $1,400,000.

We do not have a compensation committee. Unless otherwise specified, when we refer herein to the compensation committee, we are referring to the compensation committee of the board of directors of DCP Midstream, LLC. When we refer herein to the board of directors, we are referring to the board of directors of our General Partner.

Compensation Decisions

All compensation decisions concerning the officers and employees dedicated to our operations and management are made by the compensation committee except with regard to equity-based compensation, which is subject to approval by the board of directors of our General Partner. The compensation committee's responsibilities on compensation matters include the following:

- annually review the Partnership's goals and objectives relevant to compensation of the NEOs;
- annually evaluate the NEO's performance in light of the Partnership's goals and objectives, and approve the compensation levels for the NEOs;
- periodically evaluate the terms and administration of the Partnership's short-term and long-term incentive plans to assure that they are structured and administered in a manner consistent with the Partnership's goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments if appropriate;
- retain and terminate any compensation consultant to be used to assist in the evaluation of non-employee director and NEO compensation; and
- periodically review the compensation of the non-employee directors.

Compensation Philosophy

Our compensation program is structured to provide the following benefits:

- attract, retain and reward talented executive officers and key management employees by providing total compensation competitive with that of other executive officers;
- motivate executive officers and key management employees to achieve strong financial and operational performance;
- emphasize performance-based compensation, balancing short-term and long-term results; and
- reward individual performance.

Methodology - Advisors and Peer Companies

The compensation committee reviews data from market surveys provided by independent consultants to assess our competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our NEOs as well as the compensation package for directors who are not officers or employees of the General Partner or its affiliates, or our non-employee directors. With respect to NEO compensation, the compensation committee also considers individual performance, levels of responsibility, skills and experience. In 2013, we engaged the services of BDO USA, LLP, or BDO, a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for the NEOs for 2014. We consider BDO to be independent of the Partnership and therefore, the work performed by BDO does not create a conflict of interest. The BDO study was based on compensation as reported in the annual reports on Form 10-K for a group of peer companies with a similar tax status, and the 2013 TowersWatson General Industry Executive Compensation Survey, or the TowersWatson survey.

The study was comprised of the following peer companies:

Access Midstream Partners, L.P.	Niska Gas Storage Partners, LLC
Atlas Pipeline Partners, L.P.	NuStar Energy, L.P.
Boardwalk Pipeline Partners, L.P.	ONEOK Partners, L.P.
Buckeye Partners, L.P.	Penn Virginia Resource Partners, L.P.
Crestwood Midstream Partners, L.P.	Plains All American Pipeline, L.P.
Crosstex Energy, L.P.	Regency Energy Partners, L.P.
Eagle Rock Energy Partners, L.P.	Southcross Energy Partners, L.P.
Enbridge Energy Partners, L.P.	Spectra Energy Partners, L.P.
Enterprise Products Partners L.P.	Sunoco Logistics Partners, L.P.
Genesis Energy, L.P.	Summit Midstream Partners, L.P.
Inergy Midstream, L.P.	Targa Resources Partners, L.P.
Kinder Morgan Energy Partners, L.P.	Western Gas Partners, L.P.
Magellan Midstream Partners, L.P.	Williams Partners, L.P.
MarkWest Energy Partners, L.P.	

Studies such as this generally include only the most highly compensated officers of each company, which correlates with our General Partner’s NEOs. The results of this study, as well as other factors such as our targeted performance objectives and the compensation packages of highly compensated officers of DCP Midstream, LLC, served as a benchmark for establishing our total annual direct compensation packages. In order to assess the competitiveness of the total direct compensation packages for our General Partner’s NEOs, we used the data point that represents the mid point between the 25th percentile and the 50th percentile for peer positions from the BDO study and the data point that represents the 50th percentile of the market in the TowersWatson survey.

Components of Compensation

The total annual direct compensation program for NEOs of the General Partner consists of three components: (1) base salary; (2) a short-term cash incentive, or STI, which is based on a percentage of annual base salary; and (3) the present value of an equity-based grant under our long-term incentive plan, or LTIP, which is based on a percentage of annual base salary. Under our compensation structure, the allocation between base salary, STI and LTIP varies depending upon job title and responsibility levels. In 2014, this allocation for targeted compensation of our General Partner’s NEOs was as follows:

	Base Salary	Targeted STI Level	Targeted LTIP Level
Wouter T. van Kempen, Chairman of the Board and CEO (a)	N/A	N/A	N/A
Sean P. O'Brien, Group Vice President and CFO (a)	N/A	N/A	N/A
William S. Waldheim, President	35%	21%	44%
Michael S. Richards, Vice President, General Counsel and Secretary	44%	20%	36%

(a) Compensation for Messrs. van Kempen and O'Brien, each of whom devoted less than a majority of his time to the operations and management of the Partnership, was provided by DCP Midstream, LLC. The Partnership reimbursed DCP Midstream, LLC for their services under the Services Agreement, which reimbursement amount was based on the percentage of time allocated to our business during 2014.

In allocating compensation among these components, we believe a significant portion of the compensation of the NEOs should be performance-based since these individuals have a greater opportunity to influence our performance. In making this allocation, we have relied in part on the BDO study of the companies named above. Each component of compensation is further described below.

Base Salary - Base salaries for NEOs are determined based upon job responsibilities, level of experience, individual performance, comparisons to the salaries of highly compensated officers of DCP Midstream, LLC and comparisons to the salaries of individuals in similar positions obtained from the BDO study. The goal of the base salary component is to compensate NEOs at a level that approximates the median salaries of individuals in comparable positions at comparably sized companies in our industry.

The base salaries for NEOs are generally reevaluated annually as part of our performance review process, or when there is a change in the level of job responsibility. The compensation committee annually considers and approves a merit increase in base salary based upon the results of this performance review process. Merit increases are based on review of individual performance in certain categories, including: business values, safety, health and environment, leadership, financial results, project results, attitude, ability and knowledge. The compensation committee approved increases in NEO base salaries for 2014 at 3.5%. The base salaries earned by our NEOs, other than Messrs. van Kempen and O'Brien, are set forth in the "Summary Compensation" table below.

Annual Short-Term Cash Incentive - Under the STI, annual cash incentives are provided to executives to promote the achievement of our performance objectives. Target incentive opportunities for executives under the STI are established as a percentage of base salary. Incentive amounts are intended to provide total cash compensation at the market median for executive officers in comparable positions when target performance is achieved, below the market median when performance is less than target and above the market median when performance exceeds target. The BDO study was used to determine the competitiveness of the incentive opportunity for comparable positions. STI payments are generally paid in cash in March of each year for the prior fiscal year's performance.

In 2014, the STI objectives were initially designed and proposed by our CEO and Chairman of the board of directors working with the compensation committee, with objectives that were oriented towards the Partnership and DCP Midstream, LLC (collectively, the "DCP enterprise"). These objectives were intended to promote the achievement of performance objectives of the Partnership and the DCP enterprise and historically account for 75% - 80% of the award, with personal objectives accounting for 20% - 25% of the award. Personal objectives focus on specific objectives to be targeted by each NEO for that particular fiscal year. The President's objectives were reviewed and revised by the CEO and Chairman of the board of directors and were approved by the compensation committee. The STI objectives approved by the compensation committee were divided as follows depending on the NEO's title: (1) Partnership and DCP enterprise objectives accounted for 75% - 80% of the STI and (2) personal objectives accounted for 20% - 25% of the STI. All STI objectives are subject to change each year. The target STI opportunities for 2014 as a percentage of base salary were as follows:

	Targeted STI Opportunity
William S. Waldheim, President	60%
Michael S. Richards, Vice President, General Counsel and Secretary	45%

For 2014, there were four stated Partnership and DCP enterprise objectives under the STI which accounted for 75% - 80% of the total STI. The stated objectives for the President and the Vice President, General Counsel and Secretary are described below and were weighted as indicated for each.

1. *Net Income.* An objective intended to capture the net income of DCP Midstream, LLC, the owner of our General Partner and the operator of our assets ("DCP Midstream, LLC"), and which consolidates the financial results of the DCP enterprise. For this objective, the target level of performance is net income of $510 million, the maximum level of performance is net income of $970 million and the minimum level of performance is $165 million. This objective accounts for 35% of each NEO's total STI.

2. *EBIT ROCE.* An objective intended to capture the constant price EBIT (earnings before interest and taxes) ROCE (return on capital employed) of DCP Midstream, LLC. For this objective, the target level of performance is EBIT ROCE of 11.2%, the maximum level of performance is EBIT ROCE of 14.1% and the minimum level of performance is EBIT ROCE of 8.3%. This objective accounts for 30% of the President's total STI and 25% of the other NEO's total STI.

3. *Recordable Injury Rate (RIR).* A safety objective covering both our assets and the assets of DCP Midstream, LLC. For this objective, the target level of performance during the year is an RIR of 0.52, the maximum level of performance is an RIR of 0.30 and a minimum level of performance is an RIR of 0.90. This objective accounts for 10% of each NEO's total STI.

4. *Title V Environmental Deviations.* An environmental objective of non-routine air emissions, natural gas vented or flared, covering both our assets and the assets of DCP Midstream, LLC. For this objective, we have established certain levels of emissions at the assets of DCP Midstream, LLC and the Partnership that comprise the minimum, target and maximum level of performance for this objective. This objective accounts for 5% of each NEO's total STI.

The payout on these objectives range from 0% if the minimum level of performance is not achieved, 50% if the minimum level of performance is achieved, 100% if the target level of performance is achieved and 200% if the maximum level of performance is achieved. When the performance level falls between these percentages, payout will be determined by straight-line interpolation.

The level of performance achieved in 2014 for each of the Partnership objectives was as follows:

STI Partnership Objectives	**Level of Performance Achieved**
1) Net Income	Between Minimum and Target
2) EBIT ROCE	Between Minimum and Target
3) Recordable Injury Rate (RIR)	Between Target and Maximum
4) Title V Environmental Deviations	Between Minimum and Target

For 2014, the NEO's personal objectives under the STI accounted for 20% of the total STI for the President and 25% of the total STI for the other NEO. The personal objectives were approved by the compensation committee. Each of the personal objectives and the weighting of each personal objective is described below for the President:

1) *Safety and Environmental Leadership.* Continue to drive the safety and environmental performance culture at the DCP enterprise to an industry leading position. This objective accounts for 4% of the President's total STI

2) *Operational Excellence and Cost Management.* Identify long term operational excellence improvements and manage cost budgets. This objective accounts for 4% of the President's total STI.

3) *Project Identification and Execution.* Continue to advance projects to underpin the long term growth for the DCP enterprise and deliver major projects on time/on budget and with economic returns consistent with Board approvals. This objective accounts for 4% of the President's total STI.

4) *Partnership Performance.* Continue to position the Partnership as an attractive source of capital to fund growth at the DCP enterprise. This objective accounts for 4% of the President's total STI.

5) *Organizational Development.* Continue to evolve a culture with a focus on development of capability, operational excellence, leadership, initiative, stability, accountability, commitment to excellence, collaboration, transparency and teamwork to drive results and effectiveness. This objective accounts for 4% of the President's total STI.

The personal objectives for the other NEO in 2014 involved a combination of reduction of costs, asset EBIT/reliability and major project execution and initiatives at the DCP enterprise. These objectives collectively account for 25% of the other NEO's total STI in 2014.

The payout on the individual personal objectives range from 0% if the minimum level of performance is not achieved, 50% if the minimum level of performance is achieved, 100% if the target level of performance is achieved and 200% if the maximum level of performance is achieved. When the performance level falls between these percentages, payout will be determined by straight-line interpolation.

Early in 2015, management prepared a report on the achievement of the Partnership objectives and the personal objectives. These results were reviewed and approved by the compensation committee in February 2015, including a calculation of the percentage achievement of each objective for purposes of the STI program. The total payout under the STI for fiscal year 2014 including both Partnership objectives and personal objectives was 89.9% of target for the President and 90.35% of target for the other NEO.

Long-Term Incentive Plan - The LTIP has the objective of providing a focus on long-term value creation and enhancing executive retention. Under our LTIP, we issued phantom limited partner units to each NEO, except for Messrs. van Kempen and O'Brien and Ms. Robeson, under our 2005 Long Term Incentive Plan and our 2012 Long Term Incentive Plan. Half of such phantom units are performance phantom units, or PPUs, and half are restricted phantom units, or RPUs. The PPUs will vest based upon the level of achievement of certain performance objectives over a three-year performance period, or the Performance Period. The RPUs will vest if the executive officer remains employed at the end of a three-year vesting period, or the Vesting Period. We believe this program promotes retention of the executive officers, and focuses the executive officers on the goal of long-term value creation.

For 2014, the PPUs had the following two performance measures: (1) total shareholder return, or TSR, over the Performance Period relative to a peer group of 13 other similar publicly held master limited partnerships that we believe we compete with in the capital markets, and (2) EBIT return on capital employed, or EBIT ROCE, by DCP Midstream, LLC over the Performance Period. Half of the PPUs will be measured against the TSR performance objective and half of the PPUs will be measured against the EBIT ROCE performance measure. These performance measures were initially designed and proposed by the CEO and Chairman of the board of directors. These objectives were then considered and approved by the compensation committee and ultimately by the board of directors. The board of directors believes utilizing TSR as a performance measure provides incentive for the continued growth of our operating footprint and distributions to unitholders. The board of directors believes utilizing EBIT ROCE of DCP Midstream, LLC aligns the performance of the executive officers with the success of the DCP enterprise. We believe these performance measures provide management with appropriate incentives for our disciplined and steady growth.

For the 2014 TSR performance measure, the companies included in the peer group that will be compared against the Partnership were the following:

Access Midstream Partners, L.P.	MarkWest Energy Partners, L.P.
Atlas Pipeline Partners, L.P.	ONEOK Partners, L.P.
Crestwood Midstream Partners, L.P.	Regency Energy Partners L.P.
Crosstex Energy, L.P.	Targa Resources Partners L.P.
Enbridge Energy Partners, L.P.	Western Gas Partners, L.P.
Energy Transfer Partners L.P.	Williams Partners L.P.
Enterprise Products Partners L.P.	

If our TSR ranking among the companies listed above over the Performance Period is below the 25th percentile, 0% - 50% of the performance units will vest. If the TSR ranking over the Performance Period is greater than the 25th percentile but less than or equal to the 50th percentile, 50% - 100% of the performance units will vest. If the TSR ranking over the Performance Period is greater than the 50th percentile but less than or equal to the 75th percentile, 100% - 175% of the performance units will vest. If the TSR ranking over the Performance Period is greater than the 75th percentile, 175% - 200% of the performance units will vest. Final vesting within a performance quartile will be determined by the board of directors. TSR is computed by using data obtained from Bloomberg for the peer group and will incorporate the average closing prices of the 20 trading days ending on December 31, 2013 and December 31, 2016.

If one of these peer companies is not publicly traded at the end of the Performance Period it will remain a member of the peer group for purposes of ranking the peer group total shareholder return but it will go to the bottom of the peer group ranking. If there is a combination of any of the peer group companies during the Performance Period, the performance of the surviving entity will be used. If any member of the peer group is acquired by a company outside of the peer group, it will fall out of the peer group. No new companies will be added to the peer group during the Performance Period (including a non-peer company) that may acquire a member of the peer group.

For the EBIT ROCE performance measure, EBIT will be for DCP Midstream, LLC as reported in its financial statements. Capital employed will be determined each year during the annual budget process as approved by the board of directors of DCP Midstream, LLC. The EBIT ROCE targets are reset each year and will be based on the average of the three one-year periods running from 2014 through 2016. For this objective, the target level of performance for 2014 was EBIT ROCE of 11.2%, the maximum level of performance is EBIT ROCE of 14.1% and the minimum level of performance is EBIT ROCE of 8.3%.

These PPU and RPU awards were granted at the first regular meeting of the board of directors during the first quarter of 2014. The number of awards granted to our executive officers is set forth in the "Grants of Plan-Based Awards" table below. Award recipients also received the right to receive dividend equivalent rights, or DERs, on the number of units earned during the Vesting Period. The DERs on the PPUs will be paid in cash at the end of the Performance Period and the DERs on the RPUs are paid quarterly in cash during the Vesting Period. The amount paid on the DERs will equal the quarterly distributions actually paid on the underlying securities during the Performance Period and the Vesting Period on the number of PPUs earned or RPUs granted, respectively.

Our practice is to determine the dollar amount of long-term incentive compensation that we want to provide, and to then grant a number of PPUs and RPUs that have a fair market value equal to that amount on the date of grant, which is based on the average closing prices of the underlying securities on the NYSE for the 20 trading days prior to the date of grant for the 2012 Long-Term Incentive Plan, and based on the closing price on the date of grant for the 2005 Long-Term Incentive Plan. Target long-term incentive opportunities for executives under the plan are established as a percentage of base salary, using the BDO study data for individuals in comparable positions.

The target 2014 long-term incentive opportunities, expressed as a percentage of base salary were as follows:

	Targeted LTI Opportunity
William S. Waldheim, President	125%
Michael S. Richards, Vice President, General Counsel and Secretary	80%

In the event that any person other than DCP Midstream, LLC and/or an affiliate thereof becomes the beneficial owner of more than 50% of the combined voting power of the General Partner's equity interests prior to the completion of the Performance Period, the PPUs, RPUs and related DERs will (i) be replaced with equivalent units of the new enterprise if there is no change in the recipient's job status for twelve months or (ii) fully vest if the recipient is severed or if the recipient's job is lower in status within twelve months of the change in control.

In the event an award recipient's employment is terminated after the first anniversary of the grant date for reasons of death, disability, early or normal retirement, or if the recipient is terminated by the General Partner for reasons other than cause, the recipient's (i) PPUs will contingently vest on a pro rata basis for time worked over the Performance Period and final performance, measured at the end of the Performance Period, will determine the payout and (ii) RPUs will become fully vested and payable. Termination of employment for any other reason will result in the forfeiture of any unvested units and unpaid DERs.

Other Compensation - In addition, executives are eligible to participate in other compensation programs, which include but are not limited to:

Company Matching and Retirement Contributions to Defined Contribution Plans - Executives may elect to participate in the DCP Midstream, LP 401(k) and Retirement Plan. Under the plan, executives may elect to defer up to 75% of their eligible compensation, or up to the limits specified by the Internal Revenue Service. We match the first 6% of eligible compensation contributed by the executive to the plan. In addition, we make retirement contributions ranging from 4% to 7% of the eligible compensation of qualifying participants to the plan, based on years of service, up to the limits specified by the Internal Revenue Service. We have no defined benefit plans.

Miscellaneous Compensation - Executive officers are eligible to participate in the DCP Midstream, LLC non-qualified deferred compensation program. Executive officers are allowed to defer up to 75% of their base salary, up to 90% of their STI and up to 100% of their LTIP or other compensation. Executive officers elect either to receive amounts contributed during specific plan years as a lump sum at a specific date, subject to Internal Revenue Service rules, as an annuity (up to five years) at a specific date, subject to Internal Revenue Service rules, or in a lump sum or annual annuity (over three to ten years) at termination.

Within the DCP Midstream, LLC non-qualified deferred compensation program is a non-qualified, defined contribution retirement plan in which benefits earned under the plan are attributable to compensation in excess of the annual compensation limits under section 401(k) of the Internal Revenue Code. Under this part of the plan, we make a contribution of up to 13% of eligible compensation, as defined by the plan, to the DCP Midstream, LLC non-qualified deferred compensation program. The cost associated with executive officers' participation in the plan is reimbursed to DCP Midstream, LLC under our Services Agreement.

In addition, we provide employees, including the executive officers, with a variety of health and welfare benefit programs. The health and welfare programs are intended to protect employees against catastrophic loss and promote well-being. These programs include medical, pharmacy, dental, life insurance, and accidental death and disability. We also provide all employees with a monthly parking pass or a pass to be used on public transportation systems.

We are a partnership and not a corporation for U.S. federal income tax purposes, and therefore, are not subject to the executive compensation tax deductible limitations of Internal Revenue Code §162(m). Accordingly, none of the compensation paid to NEOs is subject to the limitation.

Board of Directors Report on Compensation

Our General Partner's board of directors does not have a compensation committee. The board of directors of the General Partner has reviewed and discussed with management the "Compensation Discussion and Analysis" presented above. Members of management with whom the board of directors had discussions are the CEO and the President of the General Partner and the Chief Corporate Officer of DCP Midstream, LLC. In addition, the compensation committee engaged the services of BDO USA, LLP, a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for the executives. Based on this review and discussion, we recommended that the "Compensation Discussion and Analysis" referred to above be included in this annual report on Form 10-K for the year ended December 31, 2014.

The information contained in this Board of Directors Report on Compensation shall not be deemed to be "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any filing with the SEC, or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that we specifically incorporate it by reference into a document filed under the Securities Act or the Exchange Act.

Board of Directors
Wouter T. van Kempen (Chairman)
Guy Buckley
Paul F. Ferguson, Jr.
R. Mark Fiedorek
Frank A. McPherson
Thomas C. Morris
Stephen R. Springer
Andy Viens
William S. Waldheim
Brian R. Wenzel

Executive Compensation

The following tables disclose the compensation of the General Partner's NEOs, or, collectively, the "executive officers," except for the CEO, Wouter van Kempen, and the CFO, Sean O'Brien. Each of Messrs. van Kempen and O'Brien devoted approximately 25% of his time to our management and operations in 2014. Pursuant to the Services Agreement, we reimburse DCP Midstream, LLC for the allocated portion of time that Mr. van Kempen spends on our matters. In early 2014, we announced the departure of Ms. Robeson as the Senior Vice President and CFO of the General Partner and the appointment of Mr. O'Brien as the Group Vice President and CFO of the General Partner. Pursuant to the Services Agreement, we reimburse DCP Midstream, LLC for the allocated portion of time that Mr. O'Brien spends on our matters. In 2014, the general and administrative fee we paid to DCP Midstream, LLC included an aggregate of $700,000 as reimbursement for the time allocated to our business by Messrs. van Kempen and O'Brien. Messrs. van Kempen and O'Brien are not included in these tables because they do not receive any separate amounts of compensation for their services to our business or as executive officers of our General Partner and we do not pay any compensation amounts to Messrs. van Kempen and O'Brien except for amounts directly reimbursed through the general and administrative fee that we pay to DCP Midstream, LLC pursuant to the terms of the Services Agreement.

Name and Principal Position	Year	Salary	LTIP Awards (c)	Non-Equity Incentive Plan Compensation (d)	All Other Compensation (e)	Total
William S. Waldheim (a)	2014	$ 410,231	$ 517,227	$ 221,278	$ 222,876	$ 1,371,613
President	2013	$ 395,961	$ 492,880	$ 286,161	$ 182,839	$ 1,357,841
	2012	$ 118,461	$ —	$ 66,421	$ 16,543	$ 201,425
Rose M. Robeson (b)	2014	$ 82,415	$ —	$ —	$ 71,072	$ 153,487
former Senior Vice President	2013	$ 299,443	$ 296,675	$ 180,340	$ 112,398	$ 888,856
and Chief Financial Officer	2012	$ 180,336	$ —	$ 65,169	$ 21,736	$ 267,241
Michael S. Richards	2014	$ 228,100	$ 183,878	$ 92,740	$ 94,297	$ 599,015
Vice President, General	2013	$ 221,415	$ 176,164	$ 120,013	$ 89,291	$ 606,883
Counsel and Secretary	2012	$ 213,074	$ 171,869	$ 79,039	$ 187,639	$ 651,621

(a) Mr. Waldheim's employment with the General Partner commenced in September 2012. The 2012 compensation amounts represent the General Partner's pro rata share of Mr. Waldheim's salary, which was paid by DCP Midstream, LLC, the owner of the General Partner, and participation in DCP Midstream, LLC's STI program.

(b) Ms. Robeson's employment with the General Partner commenced in May 2012 and ended in January 2014.

(c) The amounts in this column reflect the grant date fair value of LTIP awards in accordance with the provisions of the FASB Accounting Standards Codification 718, *Compensation - Stock Compensation*, or ASC 718. PPU awards are subject to performance conditions. For PPUs granted in 2014, 2013, and 2012, the performance conditions are between 0% if the minimum level of performance is not achieved and 200% if the maximum level of performance is achieved. The maximum value of the PPUs, based on the grant date fair value, for Mr. Waldheim was $517,227 and $490,097 for units granted during 2014 and 2013, respectively. The maximum value of the PPUs, based on the grant date fair value, for Ms. Robeson was $293,892 for units granted during 2013. The maximum value of the PPUs, based on the grant date fair value, for Mr. Richards was $183,878, $175,236, and $171,869 for units granted during 2014, 2013, and 2012, respectively.

(d) The amounts in this column were earned during the fiscal year.

(e) Includes DERs, company retirement and non-qualified deferred compensation program contributions by the Partnership, the value of life insurance premiums paid by the Partnership on behalf of an executive and other deminimus compensation, which are detailed below.

William S. Waldheim, President

The LTIP awards are comprised of PPUs and RPUs pursuant to the LTIP. Under the 2014, 2013 and 2012 STI, Mr. Waldheim's target opportunity was 60% of his annual base salary, with the possibility of earning from 0% to 120% of his annual base salary in 2014, 2013 and 2012, depending on the level of performance in each of the STI objectives.

"All Other Compensation" includes the following:

	2014	2013	2012
Company retirement contributions to defined contribution plans	$ 33,800	$ 33,150	$ —
Non-qualified deferred compensation program contributions	$ 135,065	$ 122,812	$ 15,400
DERs	$ 50,035	$ 23,081	$ —
Life insurance premiums (a)	$ 3,976	$ 3,796	$ 1,143

(a) Paid by the Partnership on behalf of Mr. Waldheim.

Rose M. Robeson, former Senior Vice President and CFO

The LTIP awards are comprised of PPUs and RPUs pursuant to the LTIP. Under the 2013 and 2012 STI, Ms. Robeson's target opportunity was 50% of her annual base salary, with the possibility of earning from 0% to 100% of her annual base salary in 2013 and 2012, depending on the level of performance in each of the STI objectives.

"All Other Compensation" includes the following:

	2014	2013	2012
Company retirement contributions to defined contribution plans	$ 27,148	$ 28,050	$ 2,604
Non-qualified deferred compensation program contributions	$ —	$ 68,955	$ 18,163
DERs	$ 5,089	$ 13,891	$ —
Life insurance premiums (a)	$ 529	$ 1,502	$ 969
Vacation payout	$ 38,306	$ —	$ —

(a) Paid by the Partnership on behalf of Ms. Robeson.

Michael S. Richards, Vice President, General Counsel and Secretary

The LTIP awards are comprised of PPUs and RPUs pursuant to the LTIP. Under the 2014, 2013, and 2012 STI, Mr. Richards' target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 90% of his annual base salary in 2014, 2013, and 2012, depending on the level of performance in each of the STI objectives.

"All Other Compensation" includes the following:

	2014	2013	2012
Company retirement contributions to defined contribution plans	$ 28,600	$ 28,050	$ 27,500
Non-qualified deferred compensation program contributions	$ 35,322	$ 30,583	$ 122,933
DERs	$ 29,253	$ 29,584	$ 36,168
Life insurance premiums (a)	$ 1,122	$ 1,074	$ 1,038

(a) Paid by the Partnership on behalf of Mr. Richards.

Grants of Plan-Based Awards

Following are the grants of plan-based awards during the year ended December 31, 2014 for the General Partner's executive officers:

		Estimated Future Payouts under Non-Equity Incentive Plan Awards (a)			Estimated Future Payouts under Equity Incentive Plan Awards			Grant Date Fair Value of LTIP Awards
		Threshold	Target	Maximum	Threshold	Target	Maximum	
Name	Grant Date	($)	($)	($)	(#)	(#)	(#)	($)
William S. Waldheim	NA	$ —	$ 246,139	$ 492,277	—	—	—	$ —
PPUs	(b)	$ —	$ —	$ —	—	5,320	10,640	$ 258,614
RPUs	(c)	$ —	$ —	$ —	5,320	5,320	5,320	$ 258,614
Michael S. Richards	NA	$ —	$ 102,645	$ 205,290	—	—	—	$ —
PPUs	(b)	$ —	$ —	$ —	—	1,890	3,780	$ 91,939
RPUs	(c)	$ —	$ —	$ —	1,890	1,890	1,890	$ 91,939

(a) Amounts shown represent amounts under the STI. If minimum levels of performance are not met, then the payout for one or more of the components of the STI may be zero.

(b) The number of units shown represents units awarded under the LTIP. If minimum levels of performance are not met, then the payout may be zero.

(c) The number of units shown represents units awarded under the LTIP and these units vest at the end of the Vesting Period provided the individual is still employed by the Partnership.

The PPUs awarded on February 13, 2014 will vest in their entirety on December 31, 2016 if the specified performance conditions are satisfied and the RPUs awarded on February 13, 2014 will vest in their entirety on December 31, 2016 if the executive is still employed by the Partnership.

Outstanding Equity Awards at Fiscal Year-End

Following are the outstanding equity awards for the General Partner’s executive officers as of December 31, 2014:

	Outstanding LTIP Awards	
Name	**Equity Incentive Plan Awards: Unearned Units That Have Not Vested (a)**	**Equity Incentive Plan Awards: Market Value of Unearned Units That Have Not Vested (b)**
William S. Waldheim	11,170	$ 520,846
Rose M. Robeson (c)	1,463	$ 68,247
Michael S. Richards	7,980	$ 372,329

(a) PPUs awarded February 13, 2014 and February 14, 2013 vest in their entirety over a range of 0% to 200% on December 31, 2016 and December 31, 2015, respectively, if the specified performance conditions are satisfied. RPUs awarded February 13, 2014 and February 14, 2013, vest in their entirety on December 31, 2016 and December 31, 2015, respectively. To determine the number of unearned units and the market value, the calculation of the number of PPU’s granted on February 13, 2014 and February 14, 2013, that are expected to vest, is based on assumed performance of 100%, as the previous fiscal year performance was between minimum and target performance.

(b) Value calculated based on the closing price at December 31, 2014 of our common units at $45.43, the closing price of Spectra Energy’s common units at $36.30, and Phillips 66’s common units at $71.70.

(c) Represents Ms. Robeson's outstanding PPUs awarded February 14, 2013 that will vest in their entirety over a range of 0% to 200% on December 31, 2015 once the specified performance conditions are satisfied.

Option Exercises and Units Vested

Following are the units vested for the General Partner’s executive officers for the year ended December 31, 2014:

	Stock Awards (a)	
Name	**Number of Units Acquired on Vesting**	**Value Realized on Vesting**
William S. Waldheim	5,320	$ 248,017
Rose M. Robeson (b)	3,570	$ 177,996
Michael S. Richards	4,324	$ 209,207

(a) Includes all awards that vested during the year, regardless of whether the awards will be settled in our common units, Phillips 66 common units, Spectra Energy common units or cash.

(b) Represents Ms. Robeson's RPUs awarded February 14, 2013 that vested in their entirety at the conclusion of her employment with the General Partner.

Non-qualified Deferred Compensation

Following is the non-qualified deferred compensation for the General Partner’s executive officers for the year ended December 31, 2014:

Name	Executive Contributions in Last Fiscal Year (a)		Registrant Contributions in Last Fiscal Year (b)		Aggregate Earnings in Last Fiscal Year (c)		Aggregate Withdrawals/ Distributions		Aggregate Balance at December 31, 2014	
William S. Waldheim	$	41,023	$	122,812	$	48,228	$	—	$	289,874
Rose M. Robeson	$	13,186	$	68,955	$	7,248	$	(206,313)	$	—
Michael S. Richards	$	138,488	$	30,583	$	27,299	$	—	$	632,260

(a) These amounts are included in the “Summary Compensation” table for the year 2014 with the exception of $11,817 for Mr. Richards, which were included in the “Summary Compensation” table for the year 2013 as they related to deferrals of 2013 STI, and $69,646 for Mr. Richards, which was included in the “Summary Compensation” table for the year 2011 as it related to deferrals of 2011 PPU.

(b) These amounts are included in the “Summary Compensation” table for the year 2013.

(c) The performance of executive officers non-qualified deferred compensation is linked to certain mutual funds or to the average rating of the BBB bond index at the election of the participant.

Potential Payments upon Termination or Change in Control

The General Partner has not entered into any employment agreements with any of the executive officers. There are no formal severance plans in place for any employees in the event of termination of employment, or a change in control of the Partnership. As noted above, the PPUs, RPUs and the related DERs, will become payable to executive officers under certain circumstance related to termination or change in control. When employees terminate employment with the Partnership, they are entitled to a cash payment for the amount of unused vacation hours at the date of their termination.

The following table presents PPUs, RPUs and DERs payable as of December 31, 2014 under certain circumstances, following termination, or a change in control:

Triggering Event	PPUs		RPUs		DERs		Total	
William S. Waldheim								
Change of Control (a)	$	512,435	$	515,110	$	36,383	$	1,063,928
Termination (b)	$	179,021	$	271,127	$	16,216	$	466,364
Michael S. Richards								
Change of Control (a)	$	297,600	$	298,492	$	26,198	$	622,290
Termination (b)	$	178,917	$	211,764	$	19,013	$	409,694

(a) In the event that the recipient is severed or if the recipient’s job is lower in status within twelve months of the change of control.

(b) In the event of termination for reasons of death, disability, early or normal retirement, or if the recipient is terminated by the General Partner for reasons other than cause, at least one year after the grant date.

Compensation of Directors

General - Members of the board of directors who are officers or employees of the General Partner or its affiliates do not receive additional compensation for serving as directors. For 2014, the board approved an annual compensation package for non-employee directors, consisting of an annual $70,000 cash retainer and an annual grant of Phantom Units that approximate $70,000 of value, awarded pursuant to the LTIP, that have a six month vesting period. The directors also receive DERs, based on the number of units awarded, which are paid in cash on a quarterly basis. The Phantom Units are paid in units upon vesting. Chairpersons of committees of the board receive an additional annual cash retainer of $20,000. All annual cash retainers are paid on a quarterly basis in arrears. Directors do not receive additional fees for attending meetings of the board or its committees.

The directors will also be reimbursed for out-of-pocket expenses associated with their membership on the board of directors. Each director will be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Following is the compensation of the General Partner's non-employee directors for the year ended December 31, 2014:

Name	Fees Earned or Paid in Cash	LTIP Awards (a)	DERs	Total
Paul F. Ferguson, Jr.	$ 91,500	$ 68,600	$ 2,104	$ 162,204
Frank A. McPherson	$ 71,500	$ 68,600	$ 2,104	$ 142,204
Thomas C. Morris	$ 65,750	$ 68,600	$ 2,104	$ 136,454
Stephen R. Springer	$ 91,500	$ 68,600	$ 2,104	$ 162,204

a) The amounts in this column reflect the grant date fair value of LTIP awards in accordance with the provisions of ASC 718.

Mr. Ferguson is the audit committee chair and a member of the special committee.

Mr. McPherson is a member of the audit committee and the special committee.

Mr. Morris is a member of the audit committee and the special committee.

Mr. Springer is the special committee chair and a member of the audit committee.

Compensation Committee Interlocks and Insider Participation

As discussed above, our board of directors does not maintain a compensation committee. In 2014, the compensation committee of the board of directors of DCP Midstream, LLC, the owner of our general partner, reviewed all elements of compensation for our named executive officers, but the decisions with respect to equity-based compensation were subject to approval by our board of directors. In 2014, none of our directors, except for Messrs. van Kempen and Waldheim, have been or are officers or employees of us or our subsidiaries. Mr. Waldheim participates in deliberations of our board of directors with regard to executive compensation generally, but does not participate in deliberations or board actions with respect to his own compensation. Mr. van Kempen also participates in such deliberations of our board of directors; however, his compensation is determined and paid by DCP Midstream, LLC without the involvement of our board of directors. None of our named executive officers served as a director or member of a compensation committee of another entity that has or has had an executive officer who served as a member of our board of directors during 2014.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters*

The following table sets forth the beneficial ownership of our units and the related transactions held by:

- each person who beneficially owns 5% or more of our outstanding units as of February 19, 2015;
- all of the directors of DCP Midstream GP, LLC;
- each Named Executive Officer of DCP Midstream GP, LLC; and
- all directors and executive officers of DCP Midstream GP, LLC as a group.

Percentage of total common units beneficially owned is based on 113,950,115 common units outstanding.

Name of Beneficial Owner (a)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
DCP LP Holdings, LLC (b)	22,322,428	19.6%
Kayne Anderson Capital Advisors, L.P. (c)	13,239,210	11.6%
Tortoise Capital Advisors L.L.C. (d)	9,660,015	8.5%
OppenheimerFunds, Inc. (e)	8,093,123	7.1%
Goldman Sachs Asset Management (f)	6,903,228	6.1%
ClearBridge Investments, LLC (g)	6,892,616	6.0%
Piper Jaffray Companies (h)	5,783,552	5.1%
Wouter T. van Kempen	2,540	*
William S. Waldheim	23,800	*
Sean P. O'Brien	—	*
Michael S. Richards	20,944	*
Guy Buckley	—	*
Paul F. Ferguson, Jr.	16,134	*
R. Mark Fiedorek	—	*
Frank A. McPherson	25,466	*
Thomas C. Morris	30,467	*
Stephen R. Springer	11,300	*
Andy Viens	—	*
Brian R. Wenzel	—	*
All directors and executive officers as a group (12 persons)	130,651	*

*Less than 1%.

(a) Unless otherwise indicated, the address for all beneficial owners in this table is 370 17th Street, Suite 2500, Denver, Colorado 80202.
(b) DCP Midstream, LLC is the managing member of DCP LP Holdings, LLC and may, therefore, be deemed to indirectly beneficially own the units held by DCP LP Holdings, LLC. DCP Midstream, LLC disclaims beneficial ownership of all of the units owned by DCP LP Holdings, LP except to the extent of its pecuniary interest therein. The address of DCP LP Holdings, LLC and DCP Midstream, LLC is 370 17th Street, Suite 2500, Denver, Colorado 80202.
(c) As set forth in a Schedule 13G/A filed on January 9, 2015. The address of Kayne Anderson Capital Advisors, L.P. is 1800 Avenue of the Stars, Third Floor, Los Angeles, California 90067.
(d) As set forth in a Schedule 13G/A filed on February 10, 2015. The address of Tortoise Capital Advisors L.L.C. is 11550 Ash Street, Suite 300, Leawood, Kansas 66211.
(e) As set forth in a Schedule 13G filed on January 26, 2015. The address of OppenheimerFunds, Inc. is Two World Financial Center, 225 Liberty Street, New York, New York 10281.
(f) As set forth in a Schedule 13G filed on February 12, 2015. The address of Goldman Sachs Asset Management is 200 West Street, New York, New York 10282.
(g) As set forth in a Schedule 13G/A filed on February 17, 2015. The address of ClearBridge Investments, LLC is 620 8th Avenue, New York, New York 10018.
(h) As set forth in a Schedule 13G/A filed on February 17, 2015. The address of Piper Jaffray Companies is 800 Nicollet Mall, Suite 800, Minneapolis, Minnesota 55402.

Equity Compensation Plan Information

The following table summarizes information about our equity compensation plan as of December 31, 2014.

	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	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders	$ —	$ —	$ —
Equity compensation plans not approved by unitholders	—	—	771,785
Total	$ —	$ —	$ 771,785

(1) The long-term incentive plan currently permits the grant of awards covering an aggregate of 850,000 units. For more information on our long-term incentive plan, which did not require approval by our limited partners, refer to Item 11. "Executive Compensation-Components of Compensation."

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Distributions and Payments to our General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with our formation, ongoing operation, and liquidation. These distributions and payments are determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Operational Stage:	
Distributions of Available Cash to our General Partner and its affiliates	We will generally make cash distributions to the unitholders and to our General Partner, in accordance with their pro rata interest. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our General Partner will be entitled to increasing percentages of the distributions, up to 48% of the distributions above the highest target level. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level.
Payments to our General Partner and its affiliates	In 2014, we reimbursed DCP Midstream, LLC and its affiliates $41 million under the Services Agreement. For further information regarding the reimbursement, please see the "Services Agreement" section below.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage:	
Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Services Agreement

We have entered into a services agreement, as amended, or the Services Agreement, with DCP Midstream, LLC. Under the Services Agreement, which replaced the Omnibus Agreement on February 14, 2013, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee under the Services Agreement for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. Except with respect to the annual fee, there is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for other expenses and expenditures incurred or payments made on our behalf. In the event we acquire assets or our business otherwise expands, the annual fee under the Services Agreement is subject to adjustment based on the nature and extent of general and administrative services performed by DCP Midstream, LLC, as well as an annual adjustment based on changes to the Consumer Price Index.

On March 31, 2014, the annual fee payable under the Services Agreement was increased by approximately $15 million, prorated for the remainder of the calendar year, to $44 million. The increase was predominantly attributable to additional general and administrative expenses previously incurred directly by the Eagle Ford system being reallocated to the Services Agreement in connection with the contribution of the remaining 20% interest in the Eagle Ford system to us, bringing our ownership to 100%.

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

Our General Partner and its affiliates will also receive payments from us pursuant to the contractual arrangements described below under the caption "Contracts with Affiliates."

Any or all of the provisions of the Services Agreement, other than the indemnification provisions, will be terminable by DCP Midstream, LLC at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The Services Agreement will also terminate in the event of a change of control of us, our general partner (DCP Midstream GP, LP) or our General Partner (DCP Midstream GP, LLC).

Competition

None of DCP Midstream, LLC, or any of its affiliates, including Phillips 66 and Spectra Energy, is restricted, under either the partnership agreement or the Services Agreement, from competing with us. DCP Midstream, LLC and any of its affiliates, including Phillips 66 and Spectra Energy, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Contracts with Affiliates

We charge transportation fees, sell a portion of our residue gas and NGLs to, and purchase natural gas and NGLs from, DCP Midstream, LLC, Phillips 66 and their respective affiliates. Management anticipates continuing to purchase and sell these commodities to DCP Midstream, LLC, Phillips 66 and their respective affiliates in the ordinary course of business.

Natural Gas Gathering and Processing Arrangements

We sell NGLs processed at certain of our plants, and sell condensate removed from the gas gathering systems that deliver to certain of our systems under contracts to a subsidiary of DCP Midstream, LLC equal to that subsidiary's net weighted-average sales price, adjusted for transportation, processing and other charges from the tailgate of the respective asset.

We have a contractual arrangement with DCP Midstream, LLC, through March 2022, in which we pay DCP Midstream, LLC a fee for processing services associated with the gas we gather on our Southern Oklahoma system, which is part of our Natural Gas Services segment. In addition, we have an agreement with DCP Midstream, LLC providing for adjustments to those fees based upon plant efficiencies related to our portion of volumes from the Southern Oklahoma system being processed at DCP Midstream, LLC's plant through March 2022. In addition, as part of this arrangement, DCP Midstream, LLC pays us a fee for certain gathering services.

In conjunction with our acquisition of the O'Connor and Lucerne 1 plants, we entered into long-term fee-based processing agreements with DCP Midstream, LLC pursuant to which DCP Midstream, LLC agreed to pay us (i) a fixed demand charge on a portion of the plants' capacities, and (ii) a throughput fee on all volumes processed for DCP Midstream, LLC at the plants.

Please read Item 1. "Business - Natural Gas Services Segment - Customers and Contracts" and Note 5 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

Merchant Arrangements

Under our merchant arrangements, we use a subsidiary of DCP Midstream, LLC (DCP Midstream Marketing, LP) as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from certain of our processing plants, and then resell the aggregated natural gas primarily to third parties. DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system, included in our Northern Louisiana system, which is part of our Natural Gas Services segment, that are periodically used for the benefit of Pelico. DCP Midstream, LLC is able to source natural gas upstream of Pelico and deliver it to us and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. We purchase natural gas from DCP Midstream, LLC upstream of Pelico and transport it to Pelico under an interruptible transportation agreement with an affiliate. Our purchases from DCP Midstream, LLC are at DCP Midstream, LLC's actual acquisition cost plus any transportation service charges. Volumes that exceed our on-system demand are sold to DCP Midstream, LLC at an index-based price, less contractually agreed upon marketing fees. Please read Note 5 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

Transportation Arrangements

We have a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze and Wilbreeze pipelines, pursuant to fee-based rates that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on these pipelines under the transportation agreements.

The Wattenberg pipeline has in place a 10-year dedication and transportation agreement with a subsidiary of DCP Midstream, LLC whereby certain NGL volumes produced at several of DCP Midstream, LLC's processing facilities are dedicated for transportation on the Wattenberg pipeline. We collect fee-based transportation revenues under our tariff. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

The Texas Express, Front Range, Sand Hills and Southern Hills pipelines have in place 15-year transportation agreements, commencing at the pipelines' respective in-service dates, with DCP Midstream, LLC pursuant to which DCP Midstream, LLC has committed to transport minimum throughput volumes at rates defined in each respective pipeline's tariffs.

DCP Midstream, LLC historically is also the largest shipper on the Black Lake pipeline, primarily due to the NGLs delivered to it from certain of our processing plants.

Derivative Arrangements

We have entered into short term commodity swap contracts with DCP Midstream, LLC whereby we receive a fixed price and we pay a floating price. For more information regarding our derivative activities with DCP Midstream, LLC, please read Item 7A. "Quantitative and Qualitative Disclosures about Market Risk - Commodity Price Risk - Commodity Cash Flow Protection Activities."

Other Agreements and Transactions with DCP Midstream, LLC

In conjunction with our acquisitions of our East Texas and Southeast Texas systems, which are part of our Natural Gas Services segment, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse us for certain expenditures on East Texas and Southeast Texas capital projects. These reimbursements are for specific capital projects which have commenced within three years from the respective acquisition dates.

We pay a fee to DCP Midstream, LLC to operate our DJ Basin NGL fractionators and receive fees for the processing of DCP Midstream, LLC's committed NGLs produced by them in Colorado at our DJ Basin NGL fractionators under agreements that are effective through March 2018. We report fees associated with these activities in the consolidated statements of operations as operating and maintenance expense.

Review, Approval or Ratification of Transactions with Related Persons

Our partnership agreement contains specific provisions that address potential conflicts of interest between the owner of our general partner and its affiliates, including DCP Midstream, LLC on one hand, and us and our subsidiaries, on the other hand. Whenever such a conflict of interest arises, our general partner will resolve the conflict. Our general partner may, but is not required to, seek the approval of such resolution from the special committee of the board of directors of our general partner, which is comprised of independent directors and acts as our conflicts committee. The partnership agreement provides that our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or to our unitholders if the resolution of the conflict is:

- approved by the conflicts committee;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If our general partner does not seek approval from the special committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and 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. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to reasonably believe that he is acting in the best interests of the Partnership, unless the context otherwise requires.

In addition, our code of business ethics requires that all employees, including employees of affiliates of DCP Midstream, LLC who perform services for us and our general partner, avoid or disclose any activity that may interfere, or have the appearance of interfering, with their responsibilities to us.

Director Independence

Please see Item 10. "Directors, Executive Officers and Corporate Governance" for information about the independence of our general partner's board of directors and its committees, which information is incorporated herein by reference in its entirety.

Item 14. ***Principal Accountant Fees and Services***

The following table presents fees for professional services rendered by Deloitte & Touche LLP, or Deloitte, our principal accountant, for the audit of our financial statements, and the fees billed for other services rendered by Deloitte:

Type of Fees	Year Ended December 31, 2014	2013
	(Millions)	
Audit Fees (a)	$ 2	$ 2

(a) Audit Fees are fees billed by Deloitte for professional services for the audit of our consolidated financial statements included in our annual report on Form 10-K and review of financial statements included in our quarterly reports on Form 10-Q, services that are normally provided by Deloitte in connection with statutory and regulatory filings or engagements or any other service performed by Deloitte to comply with generally accepted auditing standards and include comfort and consent letters in connection with Securities and Exchange Commission filings and financing transactions.

For the last two fiscal years, Deloitte has not billed us for assurance and related services, unless such services were reasonably related to the performance of the audit or review of our financial statements, and are included in the table above. Deloitte has not provided any services to us over the last two fiscal years related to tax compliance, tax services and tax planning.

Audit Committee Pre-Approval Policy

The audit committee pre-approves all audit and permissible non-audit services provided by the independent auditors on a case-by-case basis. These services may include audit services, audit-related services, tax services and other services. The audit committee does not delegate its responsibilities to pre-approve services performed by the independent auditor to management or to an individual member of the audit committee. The audit committee has, however, pre-approved audit related services that do not impair the independence of the independent auditors for up to $50,000 per engagement, and up to an aggregate of $200,000 annually, provided the audit committee is notified of such audit-related services in a timely manner. The audit committee may, however, from time to time delegate its authority to any audit committee member, who will report on the independent auditor services that were approved at the next audit committee meeting.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) Financial Statement Schedules

Other schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(b) Exhibits

Exhibit Number		Description
2.1	*#	Contribution Agreement, dated October 9, 2006, between DCP LP Holdings, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on October 13, 2006).
2.2	*#	Purchase and Sale Agreement, dated March 7, 2007, between Anadarko Gathering Company, Anadarko Energy Services Company and DCP Midstream Partners, LP (attached as Exhibit 99.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
2.3	*#	Contribution and Sale Agreement, dated May 21, 2007, between Gas Supply Resources Holdings, Inc., DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
2.4	*#	Contribution Agreement, dated May 23, 2007, among DCP LP Holdings, LP, DCP Midstream, LLC, DCP Midstream GP, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).

2.5	*#	Contribution Agreement dated February 24, 2009, among DCP LP Holdings, LLC, DCP Midstream GP, LP DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 10.16 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
2.6	*#	Purchase and Sale Agreement by and Among DCP Midstream, LLC and DCP Midstream Partners, LP dated as of November 4, 2010 (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 8, 2010).
2.7	*#	Contribution Agreement between DCP Southeast Texas, LLC and DCP Partners SE Texas LLC dated as of November 4, 2010 (attached as Exhibit 2.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 8, 2010).
2.8	*#	Contribution Agreement, dated November 4, 2011, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.7 to DCP Midstream, LLC's Schedule 13D (File No. 005-81287) dated as of January 13, 2012).
2.9	*#	Contribution Agreement, dated February 27, 2012, among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 1, 2012).
2.10	*	First Amendment to Contribution Agreement, dated March 30, 2012, among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 4, 2012).
2.11	*#	Contribution Agreement among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP dated June 25, 2012 (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 29, 2012).
2.12	*#	Contribution Agreement, dated November 2, 2012, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2012).
2.13	*#	Contribution Agreement dated February 27, 2013 among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 27, 2013).
2.14	*	First Amendment to Contribution Agreement, dated March 28, 2013, among DCP LP Holdings, LLC, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 3, 2013).
2.15	*#	Purchase and Sale Agreement (O'Connor Plant) by and between DCP Midstream Partners, LP and DCP Midstream, LP dated August 5, 2013 (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 6, 2013).
2.16	*#	Purchase and Sale Agreement (Front Range Pipeline) by and among DCP Midstream Partners, LP and DCP Midstream, LP dated August 5, 2013 (attached as Exhibit 2.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 6, 2013).
2.17	*#	Purchase and Sale Agreement, dated February 25, 2014, by and between DCP Midstream, LP, as seller, and DCP Midstream Partners, LP, as buyer (attached as Exhibit 2.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 26, 2014).
2.18	*#	Contribution Agreement, dated February 25, 2014, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 26, 2014).
2.19	*	First Amendment to Contribution Agreement, dated February 27, 2014, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 28, 2014).
2.20	*	Second Amendment to Contribution Agreement, dated March 28, 2014, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 2, 2014).
3.1	*	Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005, as amended by Amendment No. 1 dated January 20, 2009 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
3.2	*	Amendment No. 2 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated February 14, 2013 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 21, 2013).
3.3	*	Amendment No. 3 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated November 6, 2013 (attached as Exhibit 3.3 to DCP Midstream Partners, LP's Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on November 6, 2013).

3.4	*	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP dated December 7, 2005 (attached as Exhibit 3.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
3.5	*	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated November 1, 2006 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
3.6	*	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated April 11, 2008 (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 14, 2008).
3.7	*	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated April 1, 2009 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
4.1	*	Indenture dated as of September 30, 2010 for the issuance of debt securities between DCP Midstream Operating, LP, as issuer, any Guarantors party thereto and The Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on September 30, 2010).
4.2	*	First Supplemental Indenture dated as of September 30, 2010 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on September 30, 2010).
4.3	*	Second Supplemental Indenture dated as of March 13, 2012 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 13, 2012).
4.4	*	Third Supplemental Indenture dated as of June 14, 2012 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 14, 2012).
4.5	*	Fourth Supplemental Indenture dated as of November 27, 2012 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 27, 2012).
4.6	*	Fifth Supplemental Indenture dated as of March 14, 2013 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 14, 2013).
4.7	*	Sixth Supplemental Indenture dated as of March 13, 2014 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 13, 2014).
4.8	*	Registration Rights Agreement by and among DCP Midstream Partners, LP and the purchasers named therein dated July 2, 2012 (attached as Exhibit 4.1 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on July 9, 2012).
10.1	*#	Contribution, Conveyance and Assumption Agreement, dated December 7, 2005, among DCP Midstream Partners, LP, DCP Midstream Operating LP, DCP Midstream GP, LLC, DCP Midstream GP, LP, Duke Energy Field Services, LLC, DEFS Holding 1, LLC, DEFS Holding, LLC, DCP Assets Holdings, LP, DCP Assets Holdings, GP, LLC, Duke Energy Guadalupe Pipeline Holdings, Inc., Duke Energy NGL Services, LP, DCP LP Holdings, LP and DCP Black Lake Holdings, LLC (attached as Exhibit 10.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.2	*+	DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 10.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.3	*+	Form of Phantom Unit and DERs Grant for Directors under the DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Registration Statement on Form S-8 (File No. 001-32678) filed with the SEC on April 20, 2007).
10.4	*+	Form of Performance Phantom Unit Grant Agreement and DERs Grant for Officers/Employees under the DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 24, 2011).
10.5	*+	Form of Restricted Phantom Unit Grant Agreement under the DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 10.5 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 1, 2011).

10.6	*+	DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.26 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012).
10.7	*+	Form of Phantom Unit and DERs Grant for Directors under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.27 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012).
10.8	*+	Form of Performance Phantom Unit Grant Agreement and DERs Grant for Officers/Employees under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.28 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012).
10.9	*+	Form of Restricted Phantom Unit Grant Agreement and DERs Grant under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.29 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012).
10.10	*	Common Unit Purchase Agreement by and among DCP Midstream Partners, LP and the purchasers named therein dated June 25, 2012 (attached as Exhibit 10.1 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 29, 2012).
10.11	*	Employee Secondment Agreement, dated as of February 14, 2013, among DCP Midstream Partners, LP and DCP Midstream, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 21, 2013).
10.12	*	Services Agreement, dated as of February 14, 2013, among DCP Midstream Partners, LP and DCP Midstream, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 21, 2013).
10.13	*	First Amendment to Services Agreement, dated August 5, 2013, by and between DCP Midstream Partners, LP and DCP Midstream, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 6, 2013).
10.14	*	Second Amendment to Services Agreement, dated March 31, 2014, by and between DCP Midstream Partners, LP and DCP Midstream, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 2, 2014).
10.15		Third Amendment to Services Agreement, dated February 23, 2015, by and between DCP Midstream Partners, LP and DCP Midstream, LP.
10.16	*	Form of Commercial Paper Dealer Agreement among DCP Midstream Operating, LP, DCP Midstream Partners, LP, and the Dealer party thereto (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on October 29, 2013).
10.17	*	Amended and Restated Credit Agreement, dated May 1, 2014, among DCP Midstream Operating, LP, DCP Midstream Partners, LP, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 7, 2014).
12.1		Computation of Ratio of Earnings to Fixed Charges.
21.1		List of Subsidiaries of DCP Midstream Partners, LP.
23.1		Consent of Deloitte & Touche LLP on Consolidated Financial Statements of DCP Midstream Partners, LP and the effectiveness of DCP Midstream Partners, LP's internal control over financial reporting.
24.1		Power of Attorney (incorporated by reference to the signature page of this Annual Report on Form 10-K).
31.1		Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2		Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1		Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2		Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101		Financial statements from the Annual Report on Form 10-K of DCP Midstream Partners, LP for the year ended December 31, 2014, formatted in XBRL: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Cash Flows, (v) the Consolidated Statements of Changes in Equity, and (vi) the Notes to the Consolidated Financial Statements.

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

\+ Denotes management contract or compensatory plan or arrangement.

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on February 25, 2015.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

By: /s/ Wouter T. van Kempen

Name: Wouter T. van Kempen
Title: Chief Executive Officer
(Principal Executive Officer)

By: /s/ Sean P. O'Brien

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

EXHIBIT INDEX

Exhibit Number		Description
2.1	*#	Contribution Agreement, dated October 9, 2006, between DCP LP Holdings, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on October 13, 2006).
2.2	*#	Purchase and Sale Agreement, dated March 7, 2007, between Anadarko Gathering Company, Anadarko Energy Services Company and DCP Midstream Partners, LP (attached as Exhibit 99.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
2.3	*#	Contribution and Sale Agreement, dated May 21, 2007, between Gas Supply Resources Holdings, Inc., DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
2.4	*#	Contribution Agreement, dated May 23, 2007, among DCP LP Holdings, LP, DCP Midstream, LLC, DCP Midstream GP, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
2.5	*#	Contribution Agreement dated February 24, 2009, among DCP LP Holdings, LLC, DCP Midstream GP, LP DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 10.16 to DCP Midstream Partners, LP’s Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
2.6	*#	Purchase and Sale Agreement by and Among DCP Midstream, LLC and DCP Midstream Partners, LP dated as of November 4, 2010 (attached as Exhibit 2.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 8, 2010).
2.7	*#	Contribution Agreement between DCP Southeast Texas, LLC and DCP Partners SE Texas LLC dated as of November 4, 2010 (attached as Exhibit 2.2 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 8, 2010).
2.8	*#	Contribution Agreement, dated November 4, 2011, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.7 to DCP Midstream, LLC’s Schedule 13D (File No. 005-81287) dated as of January 13, 2012).
2.9	*#	Contribution Agreement, dated February 27, 2012, among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 1, 2012).
2.10	*	First Amendment to Contribution Agreement, dated March 30, 2012, among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 4, 2012).
2.11	*#	Contribution Agreement among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP dated June 25, 2012 (attached as Exhibit 2.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 29, 2012).
2.12	*#	Contribution Agreement, dated November 2, 2012, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2012).
2.13	*#	Contribution Agreement dated February 27, 2013 among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 27, 2013).
2.14	*	First Amendment to Contribution Agreement, dated March 28, 2013, among DCP LP Holdings, LLC, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 3, 2013).
2.15	*#	Purchase and Sale Agreement (O'Connor Plant) by and between DCP Midstream Partners, LP and DCP Midstream, LP dated August 5, 2013 (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 6, 2013).
2.16	*#	Purchase and Sale Agreement (Front Range Pipeline) by and among DCP Midstream Partners, LP and DCP Midstream, LP dated August 5, 2013 (attached as Exhibit 2.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 6, 2013).
2.17	*#	Purchase and Sale Agreement, dated February 25, 2014, by and between DCP Midstream, LP, as seller, and DCP Midstream Partners, LP, as buyer (attached as Exhibit 2.2 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 26, 2014).
2.18	*#	Contribution Agreement, dated February 25, 2014, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 26, 2014).

2.19	*	First Amendment to Contribution Agreement, dated February 27, 2014, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 28, 2014).
2.20	*	Second Amendment to Contribution Agreement, dated March 28, 2014, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 2, 2014).
3.1	*	Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005, as amended by Amendment No. 1 dated January 20, 2009 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
3.2	*	Amendment No. 2 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated February 14, 2013 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 21, 2013).
3.3	*	Amendment No. 3 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated November 6, 2013 (attached as Exhibit 3.3 to DCP Midstream Partners, LP's Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on November 6, 2013).
3.4	*	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP dated December 7, 2005 (attached as Exhibit 3.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
3.5	*	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated November 1, 2006 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
3.6	*	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated April 11, 2008 (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 14, 2008).
3.7	*	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated April 1, 2009 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
4.1	*	Indenture dated as of September 30, 2010 for the issuance of debt securities between DCP Midstream Operating, LP, as issuer, any Guarantors party thereto and The Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on September 30, 2010).
4.2	*	First Supplemental Indenture dated as of September 30, 2010 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on September 30, 2010).
4.3	*	Second Supplemental Indenture dated as of March 13, 2012 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 13, 2012).
4.4	*	Third Supplemental Indenture dated as of June 14, 2012 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 14, 2012).
4.5	*	Fourth Supplemental Indenture dated as of November 27, 2012 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 27, 2012).
4.6	*	Fifth Supplemental Indenture dated as of March 14, 2013 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 14, 2013).
4.7	*	Sixth Supplemental Indenture dated as of March 13, 2014 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 13, 2014).
4.8	*	Registration Rights Agreement by and among DCP Midstream Partners, LP and the purchasers named therein dated July 2, 2012 (attached as Exhibit 4.1 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on July 9, 2012).

10.1	*#	Contribution, Conveyance and Assumption Agreement, dated December 7, 2005, among DCP Midstream Partners, LP, DCP Midstream Operating LP, DCP Midstream GP, LLC, DCP Midstream GP, LP, Duke Energy Field Services, LLC, DEFS Holding 1, LLC, DEFS Holding, LLC, DCP Assets Holdings, LP, DCP Assets Holdings, GP, LLC, Duke Energy Guadalupe Pipeline Holdings, Inc., Duke Energy NGL Services, LP, DCP LP Holdings, LP and DCP Black Lake Holdings, LLC (attached as Exhibit 10.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.2	*+	DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 10.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.3	*+	Form of Phantom Unit and DERs Grant for Directors under the DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Registration Statement on Form S-8 (File No. 001-32678) filed with the SEC on April 20, 2007).
10.4	*+	Form of Performance Phantom Unit Grant Agreement and DERs Grant for Officers/Employees under the DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 24, 2011).
10.5	*+	Form of Restricted Phantom Unit Grant Agreement under the DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 10.5 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 1, 2011).
10.6	*+	DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.26 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012).
10.7	*+	Form of Phantom Unit and DERs Grant for Directors under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.27 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012).
10.8	*+	Form of Performance Phantom Unit Grant Agreement and DERs Grant for Officers/Employees under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.28 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012).
10.9	*+	Form of Restricted Phantom Unit Grant Agreement and DERs Grant under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.29 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012).
10.10	*	Common Unit Purchase Agreement by and among DCP Midstream Partners, LP and the purchasers named therein dated June 25, 2012 (attached as Exhibit 10.1 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 29, 2012).
10.11	*	Employee Secondment Agreement, dated as of February 14, 2013, among DCP Midstream Partners, LP and DCP Midstream, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 21, 2013).
10.12	*	Services Agreement, dated as of February 14, 2013, among DCP Midstream Partners, LP and DCP Midstream, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 21, 2013).
10.13	*	First Amendment to Services Agreement, dated August 5, 2013, by and between DCP Midstream Partners, LP and DCP Midstream, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 6, 2013).
10.14	*	Second Amendment to Services Agreement, dated March 31, 2014, by and between DCP Midstream Partners, LP and DCP Midstream, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 2, 2014).
10.15		Third Amendment to Services Agreement, dated February 23, 2015, by and between DCP Midstream Partners, LP and DCP Midstream, LP.
10.16	*	Form of Commercial Paper Dealer Agreement among DCP Midstream Operating, LP, DCP Midstream Partners, LP, and the Dealer party thereto (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on October 29, 2013).
10.17	*	Amended and Restated Credit Agreement, dated May 1, 2014, among DCP Midstream Operating, LP, DCP Midstream Partners, LP, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 7, 2014).
12.1		Computation of Ratio of Earnings to Fixed Charges.
21.1		List of Subsidiaries of DCP Midstream Partners, LP.
23.1		Consent of Deloitte & Touche LLP on Consolidated Financial Statements of DCP Midstream Partners, LP and the effectiveness of DCP Midstream Partners, LP's internal control over financial reporting.

24.1	Power of Attorney (incorporated by reference to the signature page of this Annual Report on Form 10-K).
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Financial statements from the Annual Report on Form 10-K of DCP Midstream Partners, LP for the year ended December 31, 2014, formatted in XBRL: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Cash Flows, (v) the Consolidated Statements of Changes in Equity, and (vi) the Notes to the Consolidated Financial Statements.

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

\+ Denotes management contract or compensatory plan or arrangement.

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

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS that each person whose signature appears below constitutes and appoints each of Wouter T. van Kempen and Sean P. O'Brien as his/her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or in his name, place, and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this annual report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Wouter T. van Kempen Wouter T. van Kempen	Chief Executive Officer, Chairman of the Board and Director (Principal Executive Officer)	February 25, 2015
/s/ William S. Waldheim William S. Waldheim	President and Director	February 25, 2015
/s/ Sean P. O'Brien Sean P. O'Brien	Group Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2015
/s/ Richard A. Loving Richard A. Loving	Chief Accounting Officer (Principal Accounting Officer)	February 25, 2015
/s/ Guy Buckley Guy Buckley	Director	February 25, 2015
/s/ Paul F. Ferguson, Jr. Paul F. Ferguson, Jr.	Director	February 25, 2015
/s/ R. Mark Fiedorek R. Mark Fiedorek	Director	February 25, 2015
/s/ Frank A. McPherson Frank A. McPherson	Director	February 25, 2015
/s/ Thomas C. Morris Thomas C. Morris	Director	February 25, 2015
/s/ Stephen R. Springer Stephen R. Springer	Director	February 25, 2015
/s/ Andy Viens Andy Viens	Director	February 25, 2015
/s/ Brian R. Wenzel Brian R. Wenzel	Director	February 25, 2015

CORPORATE HEADQUARTERS

370 17th Street
Suite 2500
Denver, CO 80202
(303) 633-2900

INVESTOR RELATIONS

Andrea Attel
370 17th Street
Suite 2500
Denver, CO 80202
(303) 605-1741
arattel@dcpmidstream.com

STOCK EXCHANGE

DCP Midstream Partners, LP's common units are listed on the New York Stock Exchange under the symbol DPM.

WEBSITE

www.dcppartners.com

INDEPENDENT AUDITORS

Deloitte & Touche LLP
555 17th Street
Suite 3600
Denver, CO 80202

TRANSFER AGENT AND REGISTRAR

For registered unitholders, communication regarding name and address changes, lost certificates, and other administrative matters should be directed to:

American Stock Transfer
& Trust Company, LLC
Attn: Operations Center
6201 15th Avenue
Brooklyn, NY 11219

(800) 937-5449
Info@amstock.com

CASH DISTRIBUTIONS

DCP Midstream Partners, LP pays a quarterly cash distribution, which as of the quarter ended December 31, 2014 was $0.78 per limited partnership unit, or $3.12 annualized. This distribution was paid February 13, 2015. Future 2015 distributions are expected to be paid on or about May 15, August 14, and November 13.

Tax Information/ K-1 Inquiries:
Unitholder Schedule K-1 inquiries should be directed to our toll-free support line at (800) 230-7199, or to the Partnership's K-1 website: www.taxpackagesupport.com/dcpmidstream

PUBLICLY TRADED PARTNERSHIP ATTRIBUTES

DCP Midstream Partners, LP is a publicly traded partnership, which operates in the following distinct ways from a publicly traded stock corporation:

- Unitholders own limited partnership units instead of shares of common stock and receive cash distributions rather than dividends.
- A partnership is generally not a taxable entity and does not pay federal and state income tax, as does a corporation. Partnerships flow through all of the annual income, gains, losses, deductions, or credits to unitholders, who are required to show their allocated share of these amounts on their income tax returns, as though these items were incurred directly.
- DCP Midstream Partners provides each unitholder owning units for any portion of the year a Schedule K-1 tax package that includes each unitholder's allocated share of reportable Partnership items and other Partnership information necessary to be included in tax returns. This compares with a corporate stock-holder, who receives a Form 1099 annually detailing required tax data.

CORPORATE GOVERNANCE

DCP Midstream Partners, LP's employees and board of directors are committed to conducting our business ethically and in compliance with all laws and regulations. Our Code of Business Ethics serves as our core foundation on which we base our decision-making. We have established procedures for contacting the non-management members of the DCP Midstream Partners' board of directors. Any interested party may report complaints about accounting, auditing matters, or any other matter to any member of our board of directors by writing:

Name of Board Member or Committee
DCP Midstream Partners, LP
370 17th Street
Suite 2500
Denver, CO 80202

FORWARD-LOOKING STATEMENTS

This annual report may contain or incorporate by reference forward-looking statements as defined under the federal securities laws regarding DCP Midstream Partners, LP, including projections, estimates, forecasts, plans, and objectives. Although management believes that expectations reflected in such forward-looking statements are reasonable, no assurance can be given that such expectations will prove to be correct. In addition, these statements are subject to certain risks, uncertainties, and other assumptions that are difficult to predict and may be beyond our control. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership's actual results may vary materially from what management anticipated, estimated, projected, or expected.

Investors are encouraged to closely consider the disclosures and risk factors contained in the Partnership's annual and quarterly reports filed from time to time with the Securities and Exchange Commission. The Partnership undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise. Information contained in this annual report is unaudited, and is subject to change.

dcppartners.com

dcp Midstream Partners