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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of report (date of earliest event reported): June 13, 2014

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

Delaware	001-32678	03-0567133
(State or other jurisdiction of incorporation)	(Commission File No.)	(IRS Employer Identification No.)

370 17th Street, Suite 2500
Denver, Colorado 80202
(Address of principal executive offices) (Zip Code)

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

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the Registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

On March 28, 2014, DCP Midstream Partners, LP, or the Partnership, acquired a 35 MMcf/d cryogenic natural gas processing plant located in Weld County, Colorado, or the Lucerne 1 plant, from DCP Midstream, LLC and its affiliates. The acquisition of the Lucerne 1 plant represents a transaction between entities under common control and a change in reporting entity. Transfers of net assets or exchanges of shares between entities under common control 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. As a result, the Partnership is providing consolidated financial statements to include the financial results of the Lucerne 1 plant for all periods presented.

Attached hereto as Exhibit 12.1 is the Partnership's calculation of its Ratio of Earnings to Fixed Charges for the periods presented therein, which replaces Exhibit 12.1 in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on February 26, 2014 (the "2013 Form 10-K"). Attached hereto as Exhibit 99.1 is the Selected Financial Data, which replaces Item 6 in the 2013 Form 10-K. Attached hereto as Exhibit 99.2 is Management’s Discussion and Analysis of Financial Condition and Results of Operations, which relates to the audited Consolidated Financial Statements of the partnership as of December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012, and 2011 (the "Consolidated Financial Statements") and replaces Item 7 (but not Item 7A) in the 2013 Form 10-K. Attached hereto as Exhibit 99.3 are the Consolidated Financial Statements, which replace Item 8 in the 2013 Form 10-K. The Consolidated Financial Statements (1) give retrospective effect to the Partnership's acquisition of the Lucerne 1 plant, and (2) correct the classification of intercompany transfers in the condensed consolidating statements of cash flows within the Supplementary Information - Condensed Consolidating Financial Information footnote for the periods presented, which corrections did not have a material impact on the financial statements.

Attached hereto as Exhibit 99.4 are the Condensed Consolidating Statements of Cash Flows for the three months ended March 31, 2014 and 2103, which correct the classification of intercompany transfers within the Supplementary Information - Condensed Consolidating Financial Information footnote in the Partnership’s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014 (the "March 31, 2014 Form 10-Q") as filed with the Securities and Exchange Commission on May 7, 2014. These corrections to the footnote did not have a material impact on the interim financial statements.

Attached hereto as Exhibit 101 is the information included in Exhibits 99.3 and 99.4, formatted in XBRL, which replaces Exhibit 101 in the 2013 Form 10-K and the respective portion of Exhibit 101 in the March 31, 2014 Form 10-Q.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

Exhibit No.	Description
12.1	Ratio of Earnings to Fixed Charges.
23.1	Consent of Deloitte & Touche LLP.
99.1	Selected Financial Data.
99.2	Management's Discussion and Analysis of Financial Condition and Results of Operations.
99.3	Consolidated Financial Statements of DCP Midstream Partners, LP.
99.4	Unaudited Interim Condensed Consolidating Statements of Cash Flows of DCP Midstream Partners, LP.
101	Financial Statements of DCP Midstream Partners, LP for the year ended December 31, 2013, 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; and a portion of the Notes to the Condensed Consolidated Financial Statements for the three months ended March 31, 2014, formatted in XBRL.

SIGNATURE

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

Dated: June 13, 2014

DCP MIDSTREAM PARTNERS, LP

By: **DCP MIDSTREAM GP, LP,**
its General Partner

By: **DCP MIDSTREAM GP, LLC,**
its General Partner

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

EXHIBIT INDEX

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RATIO OF EARNINGS TO FIXED CHARGES

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

	DCP Midstream Partners, LP Year Ended December 31,				
	2013 (a)	2012 (a)	2011 (a)	2010 (a)	2009 (a)
	(Millions)				
Earnings from continuing operations before fixed charges:					
Pretax income from continuing operations before earnings from unconsolidated affiliates	$ 175	$ 191	$ 169	$ 104	$ 3
Fixed charges	68	50	36	30	30
Amortization of capitalized interest	1	—	—	—	—
Distributed earnings from unconsolidated affiliates	33	24	23	23	18
Less:					
Capitalized interest	(15)	(7)	(2)	—	(1)
Earnings from continuing operations before fixed charges	$ 262	$ 258	$ 226	$ 157	$ 50
Fixed charges:					
Interest expense, net of capitalized interest	48	39	33	29	28
Capitalized interest	15	7	2	—	1
Estimate of interest within rental expense	1	1	—	1	1
Amortization of deferred loan costs	4	3	1	—	—
Total fixed charges	$ 68	$ 50	$ 36	$ 30	$ 30
Ratio of earnings to fixed charges	3.85	5.16	6.28	5.23	1.67

(a) The financial information for the years ended December 31, 2013, 2012, 2011, 2010 and 2009 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.

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

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-142271 on Form S-8 and Registration Statement Nos. 333-182642, 333-182116, and 333-189346 on Form S-3 of our report dated February 26, 2014 (June 13, 2014 as to Notes 1, 3, 20, and 22), relating to the consolidated financial statements of DCP Midstream Partners, LP and subsidiaries (which report expresses an unqualified opinion and includes an emphasis-of-matter paragraph referring to the retrospective adjustment for the acquisition of the 100% ownership in DCP Lucerne 1 Plant, LLC acquired on March 28, 2014, from DCP Midstream, LLC, which has been accounted for in a manner similar to a pooling of interests) appearing in this Current Report on Form 8-K of DCP Midstream Partners, LP dated June 13, 2014.

/s/ Deloitte & Touche LLP

Denver, Colorado
June 13, 2014

Exhibit 99.1

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. These consolidated financial statements include our accounts, which have been combined with the historical assets, liabilities and operations of our 100% interest in our East Texas system of which we acquired a controlling additional 25.1% interest and the remaining 49.9% interest from DCP Midstream, LLC in April 2009 and January 2012, respectively; our 100% interest in our Southeast Texas system of which 33.33% and 66.67% were acquired from DCP Midstream, LLC in January 2011 and March 2012, respectively; commodity derivative hedge instruments related to the Southeast Texas storage business, which we acquired from DCP Midstream, LLC in March 2012; our 80% interest in the Eagle Ford system, of which 33.33% and 46.67% were acquired from DCP Midstream, LLC in November 2012 and March 2013, respectively; and our Lucerne 1 plant, which we acquired from DCP Midstream, LLC in March 2014. Prior to our acquisition of an additional 25.1% interest in East Texas, we accounted for our initial 25% interest as an unconsolidated affiliate using the equity method of accounting. Subsequent to our acquisition of the additional 25.1% interest in East Texas, we owned 50.1% of East Texas which we account for as a consolidated subsidiary. We currently own 100% of East Texas, which we continue to account for as a consolidated subsidiary. Prior to our acquisition of the remaining 66.67% interest in Southeast Texas, we accounted for our initial 33.33% interest as an unconsolidated affiliate using the equity method of accounting. Subsequent to our acquisition of the remaining 66.67% interest in Southeast Texas, we own 100% of Southeast Texas which we account for as a consolidated subsidiary. Prior to our acquisition of the additional 46.67% interest in the Eagle Ford system, we accounted for our initial 33.33% interest as an unconsolidated affiliate using the equity method of accounting. Subsequent to our acquisition of the additional 46.67% interest in the Eagle Ford system, we own 80% of the Eagle Ford system which we account for as a consolidated subsidiary. These transactions were between entities under common control and represented a change in reporting entity; accordingly, our financial information includes the historical results of entities and interests contributed to us by DCP Midstream, LLC for all periods presented. 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 8-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 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Exhibit 99.2 to this Form 8-K.

The table should also be read together with “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	Year Ended December 31,				
	2013 (a)	2012 (a)	2011 (a)	2010 (a)	2009 (a)
	(Millions, except per unit amounts)				
Statements of Operations Data:					
Sales of natural gas, propane, NGLs and condensate	$ 2,763	$ 2,520	$ 3,574	$ 3,118	$ 2,361
Transportation, processing and other	271	234	208	163	133
Gains (losses) from commodity derivative activity, net (b) (c)	17	70	8	3	(56)
Total operating revenues	3,051	2,824	3,790	3,284	2,438
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	2,426	2,215	3,155	2,811	2,090
Operating and maintenance expense	215	197	192	158	142
Depreciation and amortization expense	95	91	135	117	105
General and administrative expense	63	75	76	67	62
Step acquisition - equity interest re-measurement gain	—	—	—	(9)	—
Other expense (income)	8	—	(1)	(2)	1
Other income - affiliates	—	—	—	(3)	—
Total operating costs and expenses	2,807	2,578	3,557	3,139	2,400
Operating income	244	246	233	145	38
Interest expense	(52)	(42)	(34)	(29)	(28)
Earnings from unconsolidated affiliates (d)	33	26	23	23	18
Income before income taxes	225	230	222	139	28
Income tax expense	(8)	(1)	(1)	(2)	(1)
Net income	217	229	221	137	27
Net income attributable to noncontrolling interests	(17)	(13)	(30)	(12)	(7)
Net income attributable to partners	$ 200	$ 216	$ 191	$ 125	$ 20
Less:					
Net income attributable to predecessor operations (e)	(25)	(51)	(91)	(77)	(38)
General partner interest in net income	(70)	(41)	(25)	(17)	(13)
Net income (loss) allocable to limited partners	$ 105	$ 124	$ 75	$ 31	$ (31)
Net income (loss) per limited partner unit-basic	$ 1.34	$ 2.28	$ 1.73	$ 0.86	$ (0.99)
Net income (loss) per limited partner unit-diluted	$ 1.34	$ 2.28	$ 1.72	$ 0.86	$ (0.99)

	Year Ended December 31,				
	2013 (a)	2012 (a)	2011 (a)	2010 (a)	2009 (a)
	(Millions, except per unit amounts)				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 3,046	$ 2,592	$ 2,157	$ 1,860	$ 1,604
Total assets	$ 4,567	$ 3,645	$ 2,955	$ 2,651	$ 2,202
Accounts payable	$ 275	$ 223	$ 414	$ 305	$ 283
Long-term debt	$ 1,590	$ 1,620	$ 747	$ 648	$ 613
Partners’ equity	$ 1,985	$ 1,447	$ 1,299	$ 1,172	$ 829
Noncontrolling interests	$ 228	$ 189	$ 306	$ 288	$ 279
Total equity	$ 2,213	$ 1,636	$ 1,605	$ 1,460	$ 1,108
Other Information:					
Cash distributions declared per unit	$ 2.863	$ 2.700	$ 2.548	$ 2.438	$ 2.400
Cash distributions paid per unit	$ 2.820	$ 2.660	$ 2.515	$ 2.420	$ 2.400

(a) Includes the effect of the following acquisitions prospectively from their respective dates of acquisition: (1) certain companies acquired from MichCon Pipeline Company in November 2009; (2) the Wattenberg pipeline acquired from Buckeye Partners, L.P. in January 2010; (3) an additional 5% interest in Collbran Valley Gas Gathering LLC, acquired from Delta Petroleum Company in February 2010; (4) the Raywood processing plant and Liberty gathering system acquired in June 2010; (5) an additional 50% interest in Black Lake Pipeline Company, or Black Lake, acquired from an affiliate of BP PLC in July 2010; (6) Atlantic Energy acquired from UGI Corporation in July 2010;

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

(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; the Southeast Texas storage business acquired from DCP Midstream, LLC in March 2012 and the NGL Hedge acquired from DCP Midstream, LLC in April 2009 in connection with the acquisition of a 25.1% interest in East Texas.

(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 75% of East Texas unhedged in all periods prior to the second quarter of 2009 and the remaining 49.9% of East Texas unhedged for all periods from the second quarter of 2009 through the fourth quarter of 2011. Our consolidated results depict 100% of the Southeast Texas system unhedged in 2009 and 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 2009 and through October 2012, and 66.67% from November 2012 through March 2013, and 20% from April 2013 through December 31, 2013 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) Includes the net income attributable to an additional 25.1% limited liability company interest in East Texas prior to the date of our acquisition from DCP Midstream, LLC in April 2009; 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.

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 Form 8-K (and related exhibits). We refer to the assets, liabilities and operations of DCP Southeast Texas Holdings, GP, or Southeast Texas, prior to our 66.67% acquisition from DCP Midstream, LLC in March 2012, DCP SC Texas GP, or the Eagle Ford system, prior to our 33.33% and 46.67% acquisitions from DCP Midstream, LLC in November 2012 and March 2013, respectively, and the Lucerne 1 plant, prior to our acquisition from DCP Midstream, LLC in March 2014, as our "predecessor".

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 significantly mitigate on an overall Partnership basis through a multi-year hedging program, volumes of throughput and sales of natural gas, NGLs and condensate. Various factors impact both commodity prices and volumes. Commodity prices historically have been volatile and continue to be volatile. Crude oil prices have generally remained at favorable levels, while NGL and natural gas prices remain modest due to increasing supplies. The twelve-month average New York Mercantile Exchange, or NYMEX, price of natural gas futures contracts per MMBtu was $4.19, $3.54, and $3.24 as of December 31, 2013, 2012 and 2011, respectively. The twelve-month average price per gallon for NGLs was $0.84, $1.08 and $1.39 as of December 31, 2013, 2012 and 2011, respectively, and the price of crude oil per barrel was $98.04, $94.16 and $95.12 as of December 31, 2013, 2012 and 2011, respectively.

Although we have not experienced a significant impact to our natural gas throughput volumes as a result of decreased commodity prices, if commodity prices remain weak for a sustained period, our natural gas throughput volumes may be impacted, particularly if producers were to shut in gas. Natural gas drilling activity levels vary by geographic area, but in general, drilling remains firm in areas with liquids rich gas. Drilling remains weak in certain areas with dry gas where relatively lower commodity prices currently do not support the economics of drilling. However, advances in technology, such as horizontal drilling and hydraulic fracturing in shale plays, have led to certain geographic areas becoming increasingly accessible. Our long-term view is that commodity prices will be at levels that we believe will support sustained or increasing levels of domestic natural gas production. We use direct NGL hedges to mitigate a significant portion of our NGL price exposure; however, weakening of the relationship of natural gas liquids to crude oil prices does modestly impact the effectiveness of our hedging program to mitigate our exposure to price fluctuations where we use crude oil to hedge our NGL price exposure.

Our fee-based business which represents a significant portion of our estimated margins, plus our highly hedged commodity position, mitigated a significant portion of our natural gas, NGL, and condensate commodity price risk.

NGL prices are also impacted by the demand from petrochemical and refining industries. The petrochemical industry is making significant investment in building or expanding facilities to convert chemical plants from heavier oil-based feed stock to lighter NGL-based feed stock, including ethane. This increased demand should support increasing ethane supplies. In addition, propane export facilities are being expanded or built, which is supporting increasing propane supply. 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.

The global economic outlook continues to be cause for concern for U.S. financial markets and businesses and investors alike. This uncertainty may contribute to volatility in financial and commodity markets.

The amount of NGLs we produce, fractionate, transport, sell and store, may be reduced if the pipelines and storage and fractionation facilities to which we deliver NGLs are capacity constrained and cannot, or will not, accept the NGLs. Recent capacity expansions are coming online, which we believe will mitigate the risk of these NGL capacity constraints.

Increased activity levels in liquids rich gas basins combined with access to capital markets at relatively low historical costs have enabled us to continue executing our multi-faceted growth strategy, with an emphasis on dropdowns from DCP Midstream, LLC. Our multi-faceted growth strategy may take numerous forms such as dropdown opportunities from DCP Midstream, LLC, joint venture opportunities, organic build opportunities within our footprint and third-party acquisitions. Dropdowns from DCP Midstream, LLC in 2013 totaled over $1 billion. In 2014, we will continue executing our multi-faceted growth strategy, with an emphasis on dropdowns from DCP Midstream, LLC and organic growth.

Some of our recent growth projects include the following:

- On February 25, 2014, we entered into various transaction documents with DCP Midstream, LLC and its affiliates for the contribution or acquisition of (i) the remaining 20% interest in DCP SC Texas GP; (ii) a 33.33% membership interest in each DCP Southern Hills Pipeline, LLC, which owns the Southern Hills pipeline, and DCP Sand Hills Pipeline, LLC, which owns the Sand Hills pipeline; (iii) a 35 MMcf/d cryogenic natural gas processing plant located in Weld County, Colorado, or the Lucerne 1 plant; and (iv) a 200 MMcf/d cryogenic natural gas processing plant also located in Weld County, Colorado, which is currently under construction, or the Lucerne 2 plant. Total consideration for these transactions at closing was $1,220 million, subject to certain working capital and other customary adjustments. These transactions closed in March 2014.

- On August 5, 2013, we entered into a purchase and sale agreement with a 100% owned subsidiary of DCP Midstream, LLC pursuant to which the Partnership acquired all of the membership interests in DCP LaSalle Plant LLC, or the LaSalle Transaction, for consideration of $209 million, subject to certain customary purchase price adjustments. DCP LaSalle Plant LLC owns the O'Connor plant, a cryogenic natural gas processing plant with initial capacity of 110 MMcf/d, previously known as the LaSalle plant, in the DJ Basin in Weld County, Colorado. In connection with the LaSalle Transaction, we also entered into a 15-year fee-based processing agreement with an affiliate of DCP Midstream, LLC pursuant to which such affiliate 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 such affiliate at the O'Connor plant. The processing agreement commenced with commercial operations of the new plant in October 2013. As of February 2014, the O'Connor plant expansion to 160 MMcf/d is mechanically complete.

- On August 5, 2013, we entered into a purchase and sale agreement with a 100% owned subsidiary of DCP Midstream, LLC pursuant to which the Partnership acquired all of the membership interests in DCP Midstream Front Range LLC, or Front Range, for consideration of $86 million, subject to certain customary purchase price adjustments. Front Range owns a 33.33% equity interest in Front Range Pipeline LLC, a joint venture with affiliates of Enterprise and Anadarko Petroleum Corporation, which was formed to construct the Front Range pipeline, a new raw NGL mix pipeline that originates in the DJ Basin and extends approximately 435 miles to Skellytown, Texas. Enterprise is the operator of the pipeline, which was placed into service in February 2014.

- On March 28, 2013, we acquired an additional 46.67% interest in the Eagle Ford system from DCP Midstream, LLC and fixed price commodity derivative hedges for a three-year period for aggregate consideration of $626 million. We have an 80% interest in the construction of the Goliad 200 MMcf/d natural gas processing plant, including fixed price commodity price hedges, representing a total investment of approximately $290 million, which was placed into service in February 2014.

- The construction of the Texas Express pipeline, of which we own a 10% interest, is complete and commenced operations in the fourth quarter of 2013. Originating near Skellytown in Carson County, Texas, the 20-inch diameter Texas Express pipeline extends approximately 580 miles to Enterprise’s natural gas liquids fractionation and storage complex at Mont Belvieu, Texas, and provides access to other third party facilities in the area.

- Our construction of our 100% owned Eagle 200 MMcf/d natural gas processing plant is complete and commenced operations in the first quarter of 2013.

- Our expansion plan for Discovery's Keathley Canyon natural gas gathering pipeline system is progressing and is expected to be completed in the fourth quarter of 2014.

Our capital markets execution has positioned us well in terms of both liquidity and cost of capital to execute our growth plans, including dropdown opportunities with DCP Midstream, LLC. During the year ended December 31, 2013, we received net proceeds of $1,082 million from the issuance of 24,897,977 of our common units and $490 million through a public debt offering of 3.875% 10-year Senior Notes, which were used to finance our growth opportunities. In October 2013, we entered into a Commercial Paper Program pursuant to which we had $335 million outstanding as of December 31, 2013, which is included in short-term borrowings in our consolidated balance sheets. As of December 31, 2013, the unused capacity under the Credit Agreement was $664 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 2013, resulting in a 6% increase in our quarterly distribution rate over the rate declared for the fourth quarter of 2012. The distribution reflects our business results as well as our recent execution on growth opportunities.

General Trends and Outlook

During 2014, 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 highly 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 maintenance capital expenditures of between $35 million and $45 million, and approved expenditures for expansion capital of between $500 million and $600 million, for the year ending December 31, 2014. Expansion capital expenditures include construction of Discovery’s Keathley Canyon Connector, which is shown as investments in unconsolidated affiliates, construction of the Lucerne 2 plant, the Marysville NGL storage project and expansion of our Chesapeake facility, among other projects. The board of directors may, at its discretion, approve additional growth capital during the year.

We expect to continue to pursue a multi-faceted growth strategy, which includes maximizing dropdown opportunities provided by our partnership with DCP Midstream, LLC, capitalizing on organic expansion and opportunities pursuing strategic third party acquisitions in order to grow our distributable cash flows. Given the significant level of growth opportunities currently in DCP Midstream, LLC’s footprint, we would expect substantial emphasis on our dropdown objective over the next few years.

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.

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, particularly in areas with lower NGL content, should natural gas prices and drilling levels continue to experience weakness. Our long-term view is that as economic conditions improve, commodity prices should remain at levels that would support continued natural gas production in the United States. During 2013, petrochemical demand remained 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 2014.

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 80% interest in the Eagle Ford system and 100% 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.

The capacity on certain downstream NGL and natural gas infrastructure has tightened in recent periods and can be further constrained seasonally or when there is severe weather. Constrained market outlets may restrict us from operating our facilities optimally.

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 the prevailing price of NGLs. 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.

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 impact on our operations.

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 dropdowns, organic growth projects and acquistions. 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.

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 28, 2014, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.7325 per unit, payable on February 14, 2014 to unitholders of record on February 7, 2014.

On February 25, 2014, we entered into various transaction documents with DCP Midstream, LLC and its affiliates for the contribution or acquisition of (i) the remaining 20% interest in DCP SC Texas GP; (ii) a 33.33% membership interest in each DCP Southern Hills Pipeline, LLC, which owns the Southern Hills pipeline, and DCP Sand Hills Pipeline, LLC, which owns the Sand Hills pipeline; (iii) a 35 MMcf/d cryogenic natural gas processing plant located in Weld County, Colorado, or the Lucerne 1 plant; and (iv) a 200 MMcf/d cryogenic natural gas processing plant also located in Weld County, Colorado, which is currently under construction, or the Lucerne 2 plant. Total consideration for these transactions at closing was $1,220 million, subject to certain working capital and other customary adjustments. These transactions closed in March 2014. The Southern Hills pipeline is engaged in the business of transporting NGLs, and consists of approximately 800 miles of pipeline, with an expected capacity of 175 MBbls/d after completion of planned pump stations. The pipeline provides NGL takeaway service from the Midcontinent to fractionation facilities along the Texas Gulf Coast and 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. The Sand Hills pipeline is also engaged in the business of transporting NGLs and consists of approximately 720 miles of pipeline, with an expected initial capacity of 200 MBbls/d after completion of pump stations, and possible further capacity increases with the installation of additional pump stations. The pipeline provides NGL takeaway service from the Permian and Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and 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.

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 with 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, 2013. 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 and 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 Northern Louisiana system, 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. Therefore, 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 85% of our propane supplied during the year ended December 31, 2013. We primarily sell propane on a wholesale basis to propane distributors who in turn resell propane to their customers. We also sell propane in the wholesale market.

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, 2013	2012	2011
	(Millions)		
Reconciliation of net income attributable to partners to gross margin:			
Net income attributable to partners	$ 200	$ 216	$ 191
Interest expense	52	42	34
Income tax expense	8	1	1
Operating and maintenance expense	215	197	192
Depreciation and amortization expense	95	91	135
General and administrative expense	63	75	76
Other expense (income)	8	—	(1)
Earnings from unconsolidated affiliates	(33)	(26)	(23)
Net income attributable to noncontrolling interests	17	13	30
Gross margin	$ 625	$ 609	$ 635
Non-cash commodity derivative mark-to-market (a)	$ (37)	$ 21	$ 42
Reconciliation of segment net income attributable to partners to segment gross margin:			
Natural Gas Services segment:			
Segment net income attributable to partners	$ 213	$ 256	$ 240
Operating and maintenance expense	184	166	161
Depreciation and amortization expense	87	83	124
Other expense	1	—	—
Earnings from unconsolidated affiliates	(1)	(15)	(23)
Net income attributable to noncontrolling interests	17	13	30
Segment gross margin	$ 501	$ 503	$ 532
Non-cash commodity derivative mark-to-market (a)	$ (36)	$ 20	$ 42
NGL Logistics segment:			
Segment net income attributable to partners	$ 79	$ 53	$ 29
Operating and maintenance expense	16	16	16
Depreciation and amortization expense	6	6	8
Other expense (income)	3	—	(1)
Earnings from unconsolidated affiliates	(32)	(11)	—
Segment gross margin	$ 72	$ 64	$ 52
Wholesale Propane Logistics segment:			
Segment net income attributable to partners	$ 31	$ 25	$ 33
Operating and maintenance expense	15	15	15
Depreciation and amortization expense	2	2	3
Other expense	4	—	—
Segment gross margin	$ 52	$ 42	$ 51
Non-cash commodity derivative mark-to-market (a)	$ (1)	$ 1	$ —

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

	Year Ended December 31,		
	2013	2012	2011
	(Millions)		
Reconciliation of net income attributable to partners to adjusted segment EBITDA:			
Natural Gas Services segment:			
Segment net income attributable to partners (a)	$ 213	$ 256	$ 240
Non-cash commodity derivative mark-to-market	36	(20)	(42)
Depreciation and amortization expense	87	83	124
Noncontrolling interest on depreciation and income tax	(6)	(7)	(20)
Adjusted Segment EBITDA	$ 330	$ 312	$ 302
NGL Logistics segment:			
Segment net income attributable to partners	$ 79	$ 53	$ 29
Depreciation and amortization expense	6	6	8
Adjusted Segment EBITDA	$ 85	$ 59	$ 37
Wholesale Propane Logistics segment:			
Segment net income attributable to partners (b)	$ 31	$ 25	$ 33
Non-cash commodity derivative mark-to-market	1	(1)	—
Depreciation and amortization expense	2	2	3
Adjusted Segment EBITDA	$ 34	$ 26	$ 36

(a) Includes $2 million, $4 million and $5 million of lower of cost or market adjustments for the years ended December 31, 2013, 2012, and 2011, respectively.
(b) Includes $2 million, $15 million and $1 million of lower of cost or market adjustments for the years ended December 31, 2013, 2012, and 2011, 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,		
	2013	2012	2011
	(Millions)		
General and administrative expense	$ 17	$ 17	$ 19
General and administrative expense - affiliate:			
Services/Omnibus Agreement	29	26	10
Other - DCP Midstream, LLC	17	32	47
Total affiliate	46	58	57
Total	$ 63	$ 75	$ 76

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. Pursuant to the Services Agreement, we will reimburse DCP Midstream, LLC for expenses and expenditures incurred or payments made on our behalf.

In addition to the fees paid pursuant to the Services and Omnibus Agreements, we incurred allocated expenses, including insurance and internal audit fees with DCP Midstream, LLC of $2 million for the year ended December 31, 2013 and $1 million for each of the years ended December 31, 2012 and 2011, respectively. The Lucerne 1 plant incurred $1 million in general and administrative expenses directly from DCP Midstream, LLC for each of the years ended December 31, 2013, 2012 and 2011. The Eagle Ford system incurred $14 million for the year ended December 31, 2013 and $27 million for each of the years ended December 31, 2012 and 2011, respectively, in general and administrative expenses directly from DCP Midstream, LLC, which relates to the difference in the Eagle Ford system's ownership structure during these periods. For the years ended December 31, 2012 and 2011, Southeast Texas incurred $3 million and $10 million in general and administrative expenses directly from DCP Midstream, LLC, before the addition of Southeast Texas to the Omnibus Agreement in March 2012. During the year ended December 31, 2011, East Texas incurred $8 million in general and administrative expenses directly from DCP Midstream, LLC.

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 three years ended December 31, 2013, 2012, and 2011. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Year Ended December 31,			Variance 2013 vs. 2012		Variance 2012 vs. 2011	
	2013 (a)(b)	2012 (a)(b)(c)	2011 (a)(b)(c)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues (d):							
Natural Gas Services	$ 2,598	$ 2,345	$ 3,102	$ 253	11 %	$ (757)	(24)%
NGL Logistics	73	64	57	9	14 %	7	12 %
Wholesale Propane Logistics	380	415	633	(35)	(8)%	(218)	(34)%
Intra-segment eliminations	—	—	(2)	—	— %	2	100 %
Total operating revenues	3,051	2,824	3,790	227	8 %	(966)	(25)%
Gross margin (e):							
Natural Gas Services	501	503	532	(2)	— %	(29)	(5)%
NGL Logistics	72	64	52	8	13 %	12	23 %
Wholesale Propane Logistics	52	42	51	10	24 %	(9)	(18)%
Total gross margin	625	609	635	16	3 %	(26)	(4)%
Operating and maintenance expense	(215)	(197)	(192)	18	9 %	5	3 %
Depreciation and amortization expense	(95)	(91)	(135)	4	4 %	(44)	(33)%
General and administrative expense	(63)	(75)	(76)	(12)	(16)%	(1)	(1)%
Other (expense) income	(8)	—	1	8	100 %	(1)	(100)%
Earnings from unconsolidated affiliates (f)	33	26	23	7	27 %	3	13 %
Interest expense	(52)	(42)	(34)	10	24 %	8	24 %
Income tax expense	(8)	(1)	(1)	7	700 %	—	— %
Net income attributable to noncontrolling interests	(17)	(13)	(30)	4	31 %	(17)	(57)%
Net income attributable to partners	$ 200	$ 216	$ 191	$ (16)	(7)%	$ 25	13 %
Other data:							
Non-cash commodity derivative mark-to-market	$ (37)	$ 21	$ 42	$ (58)	(276)%	$ (21)	(50)%
Natural gas throughput (MMcf/d) (g)	2,307	2,359	1,990	(52)	(2)%	369	19 %
NGL gross production (Bbls/d) (g)	121,970	115,945	90,295	6,025	5 %	25,650	28 %
NGL pipelines throughput (Bbls/d) (g)	89,361	78,508	62,555	10,853	14 %	15,953	26 %
Propane sales volume (Bbls/d)	19,553	19,111	24,743	442	2 %	(5,632)	(23)%

(a) Includes our Lucerne 1 plant, retrospectively adjusted. We acquired the Lucerne 1 plant on March 28, 2014.
(b) Includes our 80% interest in the Eagle Ford system, retrospectively adjusted. We acquired a 33.33% interest in the Eagle Ford system on November 2, 2012, and a 46.67% interest on March 28, 2013.
(c) Includes our 100% interest in Southeast Texas, retrospectively adjusted. We acquired a 33.33% interest in Southeast Texas on January 1, 2011, and a 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, 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, 20% ownership of the Mont Belvieu 1 fractionator, 12.5% ownership of the Mont Belvieu Enterprise fractionator and 10% ownership of Texas Express. Earnings for Discovery, the Mont Belvieu 1 fractionator 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, 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.

Year Ended December 31, 2012 vs. Year Ended December 31, 2011

Total Operating Revenues — Total operating revenues decreased $966 million in 2012 compared to 2011 primarily as a result of the following:

- $757 million decrease for our Natural Gas Services segment primarily due to lower commodity prices in 2012 and the East Texas recovery settlement in 2011, partially offset by increases related to commodity derivative activity, fee revenue and volumes; and

- $218 million decrease for our Wholesale Propane Logistics segment due to lower volumes and prices, partially offset by an increase related to commodity derivative activity.

  These decreases were partially offset by:

- $9 million increase for our NGL Logistics segment due to an increase in volumes.

Gross Margin — Gross margin decreased $26 million in 2012 compared to 2011, primarily as a result of the following:

- $29 million decrease for our Natural Gas Services segment, primarily related to lower commodity prices, the East Texas recovery settlement in 2011 and decreased volumes and differences in gas quality across certain assets, partially offset by increased commodity derivative activity and increased volumes across certain assets; and

- $9 million decrease for our Wholesale Propane Logistics segment primarily from a lack of demand.

These decreases were partially offset by:

- $12 million increase for our NGL Logistics segment primarily as a result of increased throughput and rates on certain of our assets and our acquisition of the DJ Basin NGL fractionators, partially offset by lower volumes at certain connected processing facilities due to ethane rejection.

Operating and Maintenance Expense - Operating and maintenance expense increased in 2012 compared to 2011 primarily as a result of our acquisition of the Crossroads system in July 2012, turnaround activity at our Eagle Ford system and increased costs associated with the organic growth projects completed in 2011 at our Eagle Ford system.

Depreciation and Amortization Expense - Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful lives of our assets. 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.

Earnings from Unconsolidated Affiliates - Earnings from unconsolidated affiliates, increased in 2012 compared to 2011 primarily as a result of our acquisition of the Mont Belvieu Fractionators in July 2012.

Net Income Attributable to Noncontrolling Interests - Net income attributable to noncontrolling interests decreased in 2012 compared to 2011 as a result of our acquisition of the remaining 49.9% of our East Texas system.

Results of Operations — Natural Gas Services Segment

This segment consists of our 80% interest in the Eagle Ford system, our 100% owned Eagle Plant, our East Texas system, our Southeast Texas system, our Michigan system, our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our 75% interest in the Piceance system, our 40% interest in Discovery, and our DJ Basin system which consists of the O'Connor and Lucerne 1 plants:

	Year Ended December 31,			Variance 2013 vs. 2012		Variance 2012 vs. 2011	
	2013 (a)(b)	2012 (a)(b)(c)	2011 (a)(b)(c)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of natural gas, NGLs and condensate	$ 2,383	$ 2,123	$ 2,937	$ 260	12 %	$ (814)	(28)%
Transportation, processing and other	199	170	156	29	17 %	14	9 %
Gains from commodity derivative activity	16	52	9	(36)	(69)%	43	478 %
Total operating revenues	2,598	2,345	3,102	253	11 %	(757)	(24)%
Purchases of natural gas and NGLs	(2,097)	(1,842)	(2,570)	255	14 %	(728)	(28)%
Segment gross margin (d)	501	503	532	(2)	— %	(29)	(5)%
Operating and maintenance expense	(184)	(166)	(161)	18	11 %	5	3 %
Depreciation and amortization expense	(87)	(83)	(124)	4	5 %	(41)	(33)%
Other expense	(1)	—	—	1	100 %	—	— %
Earnings from unconsolidated affiliates (e)	1	15	23	(14)	(93)%	(8)	(35)%
Segment net income	230	269	270	(39)	(14)%	(1)	— %
Segment net income attributable to noncontrolling interests	(17)	(13)	(30)	4	31 %	(17)	(57)%
Segment net income attributable to partners	$ 213	$ 256	$ 240	$ (43)	(17)%	$ 16	7 %
Other data:							
Non-cash commodity derivative mark-to-market	$ (36)	$ 20	$ 42	$ (56)	(280)%	$ (22)	(52)%
Natural gas throughput (MMcf/d) (f)	2,307	2,359	1,990	(52)	(2)%	369	19 %
NGL gross production (Bbls/d) (f)	121,970	115,945	90,295	6,025	5 %	25,650	28 %

(a) Includes our Lucerne 1 plant, retrospectively adjusted. We acquired the Lucerne 1 plant on March 28, 2014.
(b) Includes our 80% interest in the Eagle Ford system, retrospectively adjusted. We acquired a 33.33% interest in the Eagle Ford system on November 2, 2012, and a 46.67% interest on March 28, 2013.
(c) Includes our 100% interest in Southeast Texas, retrospectively adjusted. We acquired a 33.33% interest in Southeast Texas on January 1, 2011, and a 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, 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.

Year Ended December 31, 2012 vs. Year Ended December 31, 2011

Total Operating Revenues — Total operating revenues decreased $757 million in 2012 compared to 2011, primarily as a result of the following:

- $645 million decrease attributable to the impact of lower commodity prices on our gathering and processing business;
- $167 million decrease primarily attributable to decreased prices for physical sales related to our natural gas storage and pipeline assets, as well as a decrease in volumes; and
- $6 million decrease as a result of the East Texas recovery settlement in 2011.

These decreases were partially offset by:

- $43 million increase related to commodity derivative activity. This includes a change in unrealized commodity derivative activity in 2012 compared to 2011 of $22 million due to movements in forward prices of commodities, and realized cash settlement gains in 2012 compared to realized cash settlement losses in 2011 for a net increase of $65 million. Included in our derivative activity are an increase in unrealized losses of $38 million and an increase in realized gains of $33 million from the predecessor’s Southeast Texas storage business;
- $14 million in fee revenue primarily attributable to contractual amendments such that certain revenues changed from a gross presentation to a net fee presentation; and
- $4 million increase primarily attributable to increased volumes at our Eagle Ford system, partially offset by decreased volumes across certain assets, differences in gas quality and extensive turnaround activity at our East Texas system.

Purchases of Natural Gas and NGLs - Purchases of natural gas and NGLs decreased $728 million in 2012 compared to 2011 primarily as a result of higher natural gas prices, increased volumes at our Eagle Ford system and across certain assets, partially offset by contractual amendments such that certain revenues changed from a gross presentation to a net fee presentation, decreased NGL prices and a plant turnaround at our Eagle Ford system.

Segment Gross Margin — Segment gross margin decreased $29 million in 2012 compared to 2011, primarily as a result of the following:

- $102 million decrease as a result of lower commodity prices; and
- $6 million decrease as a result of the East Texas recovery settlement in 2011.

These decreases were partially offset by:

- $43 million increase related to commodity derivative activities as discussed in the Operating Revenues section above; and
- $36 million increase primarily attributable to increased volumes at our Eagle Ford system, partially offset by decreased volumes and differences in gas quality across certain assets, and extensive turnaround activity at our East Texas system.

Operating and Maintenance Expense - Operating and maintenance expense increased in 2012 compared to 2011 primarily as a result of our acquisition of the Crossroads system in July 2012, turnaround activity at our Eagle Ford system and increased costs associated with the organic growth projects completed in 2011 at our Eagle Ford system.

Depreciation and Amortization Expense - Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful lives of our assets. 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.

Earnings from Unconsolidated Affiliates - Earnings from unconsolidated affiliates, primarily representing our 40% ownership of Discovery, decreased in 2012 compared to 2011 primarily as a result of lower commodity prices and reduced throughput volumes on Discovery, partially offset by the timing of expenditures at Discovery. 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 decreased in 2012 compared to 2011 as a result of the acquisition of the remaining 49.9% of the East Texas system.

Natural Gas Throughput - Natural gas transported, processed and/or treated increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of the East Texas system and Crossroads system, partially offset by decreased volumes across certain assets and turnaround at our East Texas system.

NGL Gross Production - NGL production increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of the East Texas system and Crossroads system, partially offset by decreased volumes and differences in gas quality across certain assets and turnaround at East Texas.

Results of Operations — NGL Logistics Segment

This segment includes the NGL storage facility in Michigan, our 20% interest in the Mont Belvieu 1 fractionator, our 12.5% interest in the Mont Belvieu Enterprise fractionator, the Black Lake and Wattenberg interstate NGL pipelines, the DJ Basin NGL fractionators in Colorado, the Seabreeze and Wilbreeze intrastate NGL pipeline, our 33.33% interest in the Front Range interstate NGL pipeline (under construction as of December 31, 2013), and our 10% interest in the Texas Express intrastate NGL pipeline:

	Year Ended December 31,			Variance 2013 vs. 2012		Variance 2012 vs. 2011	
	2013	2012	2011	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of NGLs	$ 1	$ —	$ 5	$ 1	100%	$ (5)	(100)%
Transportation, processing and other	72	64	52	8	13%	12	23 %
Total operating revenues	73	64	57	9	14%	7	12 %
Purchases of NGLs	(1)	—	(5)	1	100%	(5)	(100)%
Segment gross margin (a)	72	64	52	8	13%	12	23 %
Operating and maintenance expense	(16)	(16)	(16)	—	—%	—	— %
Depreciation and amortization expense	(6)	(6)	(8)	—	—%	(2)	(25)%
Other (expense) income	(3)	—	1	3	100%	(1)	(100)%
Earnings from unconsolidated affiliates (b)	32	11	—	21	191%	11	100 %
Segment net income attributable to partners	$ 79	$ 53	$ 29	$ 26	49%	$ 24	83 %
Other data:							
NGL pipelines throughput (Bbls/d) (c)	89,361	78,508	62,555	10,853	14%	15,953	26 %

(a) Segment gross margin consists of total operating revenues 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 20% ownership of the Mont Belvieu 1 fractionator, 12.5% ownership of the Mont Belvieu Enterprise fractionator and 10% ownership of Texas Express. Earnings for 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, 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.

Year Ended December 31, 2012 vs. Year Ended December 31, 2011

Total Operating Revenues — Total operating revenues increased in 2012 compared to 2011 as result of increased throughput and rates on certain of our pipelines, the completion of the Wattenberg capital expansion project, and our acquisition of the DJ Basin NGL fractionators, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Segment Gross Margin - Segment gross margin increased in 2012 compared to 2011 as result of increased throughput and rates on certain of our pipelines, the completion of the Wattenberg capital expansion project, and our acquisition of the DJ Basin NGL fractionators, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Operating and Maintenance Expense - Operating and maintenance expense remained relatively constant in 2012 compared to 2011due to the completion of the Wattenberg capital expansion project, and our acquisition of the DJ Basin NGL fractionators, offset by timing of expenditures.

Depreciation and Amortization Expense - Depreciation and amortization expense decreased in 2012 compared to 2011 primarily as a result of a change in the estimated useful lives of our assets. 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.

Earnings from Unconsolidated Affiliates - Earnings from unconsolidated affiliates, representing 20% ownership of the Mont Belvieu 1 Fractionator and 12.5% ownership of the Mont Belvieu Enterprise Fractionator, increased in 2012 compared to 2011 as a result the acquisition of the Mont Belvieu Fractionators in July 2012.

NGL Pipelines Throughput - NGL pipelines throughput increased in 2012 compared to 2011 as a result of volume growth on our pipelines and the completion of the Wattenberg capital expansion project, partially offset by lower throughput volumes due to ethane rejection at certain connected processing facilities.

Results of Operations — Wholesale Propane Logistics Segment

This segment consists of our propane terminals, which include six owned and operated rail terminals, one owned marine import terminal, one leased marine terminal, one pipeline terminal and access to several open-access propane pipeline terminals.

	Year Ended December 31,			Variance 2013 vs. 2012		Variance 2012 vs. 2011	
	2013	2012	2011	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of propane	$ 379	$ 397	$ 634	$ (18)	(5)%	$ (237)	(37)%
Gains (losses) from commodity derivative activity	1	18	(1)	(17)	(94)%	19	*
Total operating revenues	380	415	633	(35)	(8)%	(218)	(34)%
Purchases of propane	(328)	(373)	(582)	(45)	(12)%	(209)	(36)%
Segment gross margin (a)	52	42	51	10	24 %	(9)	(18)%
Operating and maintenance expense	(15)	(15)	(15)	—	— %	—	— %
Depreciation and amortization expense	(2)	(2)	(3)	—	— %	(1)	(33)%
Other expense	(4)	—	—	4	100 %	—	— %
Segment net (loss) income attributable to partners	$ 31	$ 25	$ 33	$ 6	24 %	$ (8)	(24)%
Other data:							
Non-cash commodity derivative mark-to-market	$ (1)	$ 1	$ —	$ (2)	(200)%	$ 1	100 %
Propane sales volume (Bbls/d)	19,553	19,111	24,743	442	2 %	(5,632)	(23)%

* Percentage change is not meaningful.

(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, 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.

Year Ended December 31, 2012 vs. Year Ended December 31, 2011

Total Operating Revenues — Total operating revenues decreased $218 million in 2012 compared to 2011, primarily as a result of the following:

- $152 million decrease attributable to reduced sales volumes primarily as a result of a lack of demand due to the industry's excess inventory resulting from record warm weather last heating season; and

- $85 million decrease attributable to lower propane prices.

These decreases were partially offset by:

- $19 million increase related to a change in unrealized commodity derivative activity of $1 million and a change in realized commodity derivative activity of $18 million.

Purchases of Propane - Purchases of propane decreased in 2012 compared to 2011 primarily due to reduced volumes as a result of inventory build resulting from record warm weather last heating season and lower propane prices, partially offset by a non-cash lower of cost or market inventory adjustment of $15 million in 2012, offset by a significant recovery through the sale of inventory.

Segment Gross Margin - Segment gross margin decreased in 2012 compared to 2011 primarily from a lack of demand due to the industry's excess inventory resulting from record warm weather last heating season and lower per unit margins. A non-cash lower of cost or market inventory adjustment of $15 million was offset by a significant recovery through the sale of inventory and hedging activity.

Operating and Maintenance Expense - Operating and maintenance expense remained relatively constant in 2012 compared to 2011.

Depreciation and Amortization Expense - Depreciation and amortization expense remained relatively constant in 2012 compared to 2011.

Propane Sales Volume - Propane sales volumes decreased in 2012 compared to 2011 as a result of a lack of demand due to the industry's excess inventory resulting from record warm weather last heating season.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;

- cash distributions from our unconsolidated affiliates;

- borrowings under our revolving Credit Agreement;

- issuance of commercial paper under our Commercial Paper Program;
- borrowings under term loans;
- issuance of additional common units, including issuances we may make to DCP Midstream, LLC;
- debt offerings; and
- letters of credit.

We anticipate our more significant uses of resources to include:

- quarterly distributions to our unitholders and general partner;
- 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, impact our credit ratings, raise our financing costs, as well as impact our compliance with our financial covenant requirements under our Credit Agreement.

Our Credit Agreement consists of a senior unsecured revolving credit facility with capacity of $1 billion, which matures on November 10, 2016. Our borrowing capacity may be limited by the Credit Agreement’s financial covenant requirements. Except in the case of a default, which would make the borrowings under the Credit Agreement fully callable, amounts borrowed under the Credit Agreement will not mature prior to the November 10, 2016 maturity date. In October 2013, we entered into a commercial paper program, or the Commercial Paper Program, which serves 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 revolving credit facility, not to exceed $1 billion in the aggregate. Amounts undrawn under our revolving credit facility are available to repay the unsecured commercial paper notes, or the Notes, if necessary. The maturities of the Notes will vary, but may not exceed 397 days from the date of issue. The proceeds of the issuances of the Notes are expected to be used for capital expenditures and other general partnership purposes. As of February 20, 2014, we had $445 million of commercial paper outstanding as short-term borrowings and had approximately $555 million of unused capacity under the Credit Agreement.

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 totaling $10 million, which we used to fund a portion of the acquisition of an additional 46.67% interest in the Eagle Ford system.

During the year ended December 31, 2013, we issued 1,408,547 of our common units pursuant to an equity distribution agreement entered into in August 2011, or the 2011 equity distribution agreement. We received proceeds of $67 million, net of commissions and offering costs of $2 million, which were used to finance growth opportunities and for general corporate purposes. The 2011 equity distribution agreement provided for the offer and sale of common units having an aggregate offering amount of up to $150 million. As of December 31, 2013, no common units remain available for sale pursuant to this equity distribution agreement and we have deregistered the corresponding registration statement.

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 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 $300 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 accrued commissions and offering costs of $1 million, which were used to finance growth opportunities and for general corporate purposes. As of December 31, 2013, approximately $212 million aggregate offering price of our common units remain available for sale pursuant to the 2013 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 significant 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”.

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 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 liabilities of $220 million as of December 31, 2013, compared to working capital assets of $23 million as of December 31, 2012. Included in these working capital amounts are net derivative working capital assets of $51 million and $18 million as of December 31, 2013 and December 31, 2012, respectively. The change in working capital is primarily attributable to the factors described above, as well as our commercial paper borrowings. We expect that our future working capital requirements will be impacted by these same factors.

As of December 31, 2013, we had $12 million in cash and cash equivalents. Cash held by consolidated subsidiaries with noncontrolling interests totaled $1 million. The remaining cash balance was available for general partnership purposes.

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

	Year Ended December 31,		
	2013	2012	2011
	(Millions)		
Net cash provided by operating activities	$ 345	$ 102	$ 417
Net cash used in investing activities	$ (1,387)	$ (1,384)	$ (538)
Net cash provided by financing activities	$ 1,052	$ 1,276	$ 122

Our predecessor's sources of liquidity, prior to its acquisition by us, included cash generated from operations and funding from DCP Midstream, LLC. Our predecessor's cash receipts were deposited in DCP Midstream, LLC's bank accounts and all cash disbursements were made from these accounts. Cash transactions for our predecessor were handled by DCP Midstream, LLC and were reflected in partners' equity as net changes in parent advances to predecessors from DCP Midstream, LLC.

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

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 and $34 million for our net hedge cash settlements for the years ended December 31, 2012 and 2011.

We received cash distributions from unconsolidated affiliates of $39 million, $24 million and $25 million during the years ended December 31, 2013, 2012, and 2011, 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 used in investing activities during 2011 was comprised of: (1) capital expenditures of $385 million (our portion of which was $322 million and the noncontrolling interest holders' portion was $63 million), which includes $23 million of capital expenditures related to our Eagle Plant construction; (2) acquisition expenditures of $114 million, representing the carrying value of the net assets acquired, related to our acquisition of an initial 33.33% interest in Southeast Texas; (3) acquisition expenditures of $30 million related to our acquisition of our DJ Basin NGL fractionators and a payment of $8 million to the seller of Michigan Pipeline & Processing, LLC in relation to our contingent payment agreement; and (4) investments in unconsolidated affiliates of $8 million; partially offset by (5) proceeds from sales of assets of $5 million; and (6) a return of investment from unconsolidated affiliates of $2 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.

Net cash provided by financing activities during 2011 was comprised of: (1) proceeds from the issuance of common units, net of offering costs, of $170 million; (2) net borrowing of long-term debt of $99 million; (3) net change in advances to predecessor from DCP Midstream, LLC of $52 million; and (4) contributions from noncontrolling interests of $18 million; partially offset by (5) distributions to our unitholders and general partner of $132 million; (6) distributions to noncontrolling interests of $45 million; (7) excess purchase price over the acquired net assets of Southeast Texas of $36 million; and (8) payment of deferred financing costs of $4 million.

During 2011, 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 $426 million and did not exceed $591 million. The weighted-average indebtedness outstanding under the revolving credit facility was $519 million, $454 million, $484 million and $517 million for the first, second, third and fourth quarters of 2011, respectively.

We had unused capacity, which is available for commitments under the Credit Agreement of $424 million, $388 million,

$373 million and $502 million at the end of the first, second, third and fourth quarters of 2011, respectively.

During 2011, we had the following movements on our revolving credit facility:

- $150 million borrowing to fund the acquisition of our initial 33.33% interest in Southeast Texas;
- $30 million borrowing to fund the purchase of the DJ Basin NGL fractionators;
- $30 million borrowing to fund the Marysville tax payment;
- $23 million borrowing to fund the purchase of certain tangible assets and land located in the Eagle Ford Shale; and
- $6 million net borrowings; partially offset by
- $140 million repayment financed by the issue of 3,596,636 common units in March 2011.

We expect to continue to use cash provided by operating activities for the payment of distributions to our unitholders and general partner. See Note 12 of the Notes to Consolidated Financial Statements in Exhibit 99.3 to this Form 8-K.

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

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

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $35 million and $45 million, and approved expenditures for expansion capital of between $500 million and $600 million, for the year ending December 31, 2014. Expansion capital expenditures include construction of Discovery’s Keathley Canyon Connector, which is shown as investments in unconsolidated affiliates, construction of the Lucerne 2 plant, the Marysville NGL storage project and expansion of our Chesapeake facility, among other projects. The board of directors may, at its discretion, approve additional growth capital during the year.

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

	Year Ended December 31, 2013			Year Ended December 31, 2012		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)					
Our portion	$ 23	$ 302	$ 325	$ 23	$ 388	$ 411
Noncontrolling interest portion and reimbursable projects (a)	2	36	38	8	65	73
Total	$ 25	$ 338	$ 363	$ 31	$ 453	$ 484

	Year Ended December 31, 2011		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)		
Our portion	$ 18	$ 304	$ 322
Noncontrolling interest portion and reimbursable projects (a)	6	57	63
Total	$ 24	$ 361	$ 385

(a) 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 have commenced within three years from the respective acquisition dates.

In addition, we invested cash in unconsolidated affiliates of $242 million, $158 million and $8 million net of returns, during the year ended December 31, 2013, 2012 and 2011 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 expansion capital expenditures.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our Credit Agreement, the issuance of additional partnership units and the issuance of Commercial Paper and 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 $277 million, $181 million and $132 million during the years ended December 31, 2013, 2012 and 2011, 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.

Description of the Credit Agreement — The Credit Agreement consists of a $1 billion revolving credit facility that matures November 10, 2016. As of December 31, 2013, there was no outstanding balance on the revolving credit facility resulting in unused revolver capacity of $664 million, all of which was available for general working capital purposes.

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, 2013 and December 31, 2012, we had $1 million outstanding letters of credit issued under the 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. Indebtedness under the Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.25% 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 0.25% based on our current credit rating. The revolving credit facility incurs an annual facility fee of 0.25% based on our current credit rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

The 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 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.

Description of Commercial Paper Program – In October 2013, we entered into a Commercial Paper Program under which we may issue unsecured commercial paper notes, or the Notes. The Commercial Paper Program serves 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 revolving credit facility, not to exceed $1 billion in the aggregate. Amounts undrawn under our revolving credit facility 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, 2013, we had $335 million of commercial paper outstanding which is included in short-term borrowings in our consolidated balance sheets.

The weighted-average interest rate on our commercial paper was 1.14% per annum, excluding the impact of interest rate swaps.

Description of Debt Securities – On March 14, 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 totaling $10 million, 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 will be 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.

On November 27, 2012, we issued $500 million of our 2.50% 5-year Senior Notes due December 1, 2017. We received net proceeds of $494 million, net of underwriters' fees, related expenses and unamortized discounts totaling $6 million, which were used to repay our then-outstanding term loans. Interest on the notes will be paid semi-annually on June 1 and December 1 of each year, commencing June 1, 2013. The notes will mature on December 1, 2017, 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.

On March 13, 2012, we issued $350 million of our 4.95% 10-year Senior Notes due April 1, 2022. We received net proceeds of $346 million, net of underwriters' fees, related expenses and unamortized discounts totaling $4 million, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Agreement. Interest on the notes is paid semi-annually on April 1 and October 1 of each year. The notes will mature on April 1, 2022, 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.

On September 30, 2010, we issued $250 million of our 3.25% Senior Notes due October 1, 2015. We received net proceeds of $248 million, net of underwriters' fees, related expense and unamortized discounts of $2 million, which we used to repay funds borrowed under the revolver portion of our Credit Agreement. Interest on the notes is paid semi-annually on April 1 and October 1 of each year. The notes will mature on October 1, 2015, unless redeemed prior to maturity. The underwriters' fees and related expense 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 Credit Facility. 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, 2013, is as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
			(Millions)		
Debt (a)	$ 2,333	$ 392	$ 357	$ 586	$ 998
Operating lease obligations (b)	94	16	26	19	33
Purchase obligations (c)	280	199	59	19	3
Other long-term liabilities (d)	27	—	3	—	24
Total	$ 2,734	$ 607	$ 445	$ 624	$ 1,058

(a) Includes interest payments on debt securities that have been issued. These interest payments are $57 million, $107 million, $86 million, and $148 million for less than one year, one to three years, three to five years, and thereafter, respectively. The above table does not include estimated payments associated with our interest rate swaps as the repayment date and/or future interest rate are indeterminable.

(b) Our operating lease obligations are contractual obligations, and primarily consist of our leased marine propane terminal and railcar leases, both of which provide supply and storage infrastructure for our Wholesale Propane Logistics business. Operating lease obligations also include natural gas storage in our Northern Louisiana system. The natural gas storage arrangement enables us to maximize the value between the current price of natural gas and the futures market price of natural gas.

(c) Our purchase obligations are contractual obligations and include purchase orders 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, the amount is based on the forward market prices as of December 31, 2013. 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 $24 million of asset retirement obligations, $1 million of environmental reserves and $2 million of firm transportation commitments recognized in the December 31, 2013 consolidated balance sheet. In addition, $11 million of deferred state income taxes was excluded as cash payments for income taxes are determined primarily by taxable income for each discrete fiscal year.

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 Exhibit 99.3 to this Form 8-K.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Inventories		
Inventories, which consist of NGLs and natural gas, are recorded at the lower of weighted-average cost or market value.	Judgment is required in determining the market value of inventory, as the geographic location impacts market prices, and quoted market prices may not be available for the particular location of our inventory.	If the market value of our inventory is lower than the cost, we may be exposed to losses that could be material. If commodity prices were to decrease by 10% below our December 31, 2013 weighted-average cost, our net income would be affected by approximately $7 million.
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. We have not recorded any impairment charges on goodwill during the year ended December 31, 2013.

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. These techniques are also used when assigning the purchase price to acquired assets and liabilities.	Using the impairment review methodology described herein, we have not recorded any impairment charges on long-lived assets during the year ended December 31, 2013. 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.
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, 2013. 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.

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, 2013 would have affected net income by approximately $14 million based on our net derivative position for the year ended December 31, 2013.
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 judgments 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, 2013 would have less than a $1 million impact on our net income.

Exhibit 99.3

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, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

The consolidated financial statements give retrospective effect for the Company's acquisition of the 100% ownership interest in DCP Lucerne 1 Plant, LLC acquired on March 28, 2014, from DCP Midstream, LLC, as a combination of entities under common control, which has been accounted for in a manner similar to a pooling of interests, as described in Note 1 to the consolidated financial statements.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 26, 2014 (June 13, 2014 as to Notes 1, 3, 20, and 22)

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12	$ 2
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $1 million and less than $1 million, respectively	130	107
Affiliates	212	132
Inventories	67	76
Unrealized gains on derivative instruments	79	49
Other	3	2
Total current assets	503	368
Property, plant and equipment, net	3,046	2,592
Goodwill	154	154
Intangible assets, net	129	137
Investments in unconsolidated affiliates	627	304
Unrealized gains on derivative instruments	87	70
Other long-term assets	21	20
Total assets	$ 4,567	$ 3,645
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 232	$ 151
Affiliates	43	72
Short-term borrowings	335	—
Unrealized losses on derivative instruments	28	31
Capital spending accrual	24	44
Other	61	47
Total current liabilities	723	345
Long-term debt	1,590	1,620
Unrealized losses on derivative instruments	1	8
Other long-term liabilities	40	36
Total liabilities	2,354	2,009
Commitments and contingent liabilities		
Equity:		
Predecessor equity	40	399
Limited partners (89,045,139 and 61,346,058 common units issued and outstanding, respectively)	1,948	1,063
General partner	8	—
Accumulated other comprehensive loss	(11)	(15)
Total partners' equity	1,985	1,447
Noncontrolling interests	228	189
Total equity	2,213	1,636
Total liabilities and equity	$ 4,567	$ 3,645

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2013	2012	2011
	(Millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 932	$ 820	$ 1,171
Sales of natural gas, propane, NGLs and condensate to affiliates	1,831	1,700	2,403
Transportation, processing and other	211	179	169
Transportation, processing and other to affiliates	60	55	39
(Losses) gains from commodity derivative activity, net	(5)	17	7
Gains from commodity derivative activity, net — affiliates	22	53	1
Total operating revenues	3,051	2,824	3,790
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	2,159	1,807	2,445
Purchases of natural gas, propane and NGLs from affiliates	267	408	710
Operating and maintenance expense	215	197	192
Depreciation and amortization expense	95	91	135
General and administrative expense	17	17	19
General and administrative expense — affiliates	46	58	57
Other expense (income)	8	—	(1)
Total operating costs and expenses	2,807	2,578	3,557
Operating income	244	246	233
Interest expense	(52)	(42)	(34)
Earnings from unconsolidated affiliates	33	26	23
Income before income taxes	225	230	222
Income tax expense	(8)	(1)	(1)
Net income	217	229	221
Net income attributable to noncontrolling interests	(17)	(13)	(30)
Net income attributable to partners	200	216	191
Net income attributable to predecessor operations	(25)	(51)	(91)
General partner's interest in net income	(70)	(41)	(25)
Net income allocable to limited partners	$ 105	$ 124	$ 75
Net income per limited partner unit — basic	$ 1.34	$ 2.28	$ 1.73
Net income per limited partner unit — diluted	$ 1.34	$ 2.28	$ 1.72
Weighted-average limited partner units outstanding — basic	78.4	54.5	43.5
Weighted-average limited partner units outstanding — diluted	78.4	54.5	43.6

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2013	2012	2011
		(Millions)	
Net income	$ 217	$ 229	$ 221
Other comprehensive income (loss):			
Reclassification of cash flow hedge losses into earnings	4	10	21
Net unrealized losses on cash flow hedges	—	—	(13)
Net unrealized losses on cash flow hedges - predecessor operations	—	(1)	(2)
Total other comprehensive income	4	9	6
Total comprehensive income	221	238	227
Total comprehensive income attributable to noncontrolling interests	(17)	(13)	(30)
Total comprehensive income attributable to partners	$ 204	$ 225	$ 197

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 an 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 additional 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 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, 2011	$ 654	$ 552	$ (6)	$ (28)	$ 288	$ 1,460
Net income	91	75	25	—	30	221
Other comprehensive (loss) income	(2)	—	—	8	—	6
Net change in advances to predecessor from DCP Midstream, LLC	42	—	—	—	15	57
Acquisition of Southeast Texas	(114)	—	—	—	—	(114)
Excess purchase price over acquired assets	—	(35)	—	(1)	—	(36)
Issuance of 4,357,921 common units	—	170	—	—	—	170
Equity-based compensation	—	3	—	—	—	3
Distributions to DCP Midstream, LLC	—	(3)	—	—	—	(3)
Distributions to limited partners and general partner	—	(108)	(24)	—	—	(132)
Distributions to noncontrolling interests	—	—	—	—	(45)	(45)
Contributions from noncontrolling interests	—	—	—	—	18	18
Balance, December 31, 2011	$ 671	$ 654	$ (5)	$ (21)	$ 306	$ 1,605

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2013	2012	2011
	(Millions)		
OPERATING ACTIVITIES:			
Net income	$ 217	$ 229	$ 221
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	95	91	135
Earnings from unconsolidated affiliates	(33)	(26)	(23)
Distributions from unconsolidated affiliates	39	24	25
Net unrealized losses (gains) on derivative instruments	36	(21)	(40)
Deferred income taxes, net	5	—	(29)
Other, net	14	3	5
Change in operating assets and liabilities, which (used) provided cash, net of effects of acquisitions:			
Accounts receivable	(89)	(11)	34
Inventories	9	14	(14)
Accounts payable	51	(194)	106
Accrued interest	5	5	—
Other current assets and liabilities	(2)	(4)	2
Other long-term assets and liabilities	(2)	(8)	(5)
Net cash provided by operating activities	345	102	417
INVESTING ACTIVITIES:			
Capital expenditures	(363)	(484)	(385)
Acquisitions, net of cash acquired	(696)	(433)	(38)
Acquisition of unconsolidated affiliates	(86)	(312)	(114)
Investments in unconsolidated affiliates	(242)	(158)	(8)
Return of investment from unconsolidated affiliate	—	1	2
Proceeds from sales of assets	—	2	5
Net cash used in investing activities	(1,387)	(1,384)	(538)
FINANCING ACTIVITIES:			
Proceeds from long-term debt	1,957	2,665	1,524
Payments of long-term debt	(1,988)	(1,792)	(1,425)
Proceeds from issuance of commercial paper	335	—	—
Payments of deferred financing costs	(4)	(8)	(4)
Excess purchase price over acquired interests and commodity hedges	(85)	(225)	(36)
Proceeds from issuance of common units, net of offering costs	1,083	455	170
Net change in advances to predecessor from DCP Midstream, LLC	11	336	52
Distributions to limited partners and general partner	(277)	(181)	(132)
Distributions to noncontrolling interests	(24)	(9)	(45)
Contributions from noncontrolling interests	46	25	18
Distributions to DCP Midstream, LLC	(3)	—	—
Contributions from DCP Midstream, LLC	1	10	—
Net cash provided by financing activities	1,052	1,276	122
Net change in cash and cash equivalents	10	(6)	1
Cash and cash equivalents, beginning of year	2	8	7
Cash and cash equivalents, end of year	$ 12	$ 2	$ 8

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 segment (which includes our 80% interest in the Eagle Ford system, our 100% owned Eagle Plant; our East Texas system; our Southeast Texas system; our Michigan system; our Northern Louisiana system; our Southern Oklahoma system; our Wyoming system; a 75% interest in Collbran Valley Gas Gathering, LLC, or Collbran or our Piceance system; our 40% interest in Discovery Producer Services LLC, or Discovery; and our DJ Basin system, consisting of our O'Connor and Lucerne 1 plants), our NGL logistics segment (which includes the NGL storage facility in Michigan, our 12.5% interest in the Mont Belvieu Enterprise fractionator, our 20% interest in the Mont Belvieu 1 fractionator, the Black Lake and Wattenberg interstate NGL pipelines, the DJ Basin NGL fractionators, the Seabreeze and Wilbreeze intrastate NGL pipelines, our 33.33% interest in the Front Range interstate NGL pipeline, and our 10% interest in the Texas Express intrastate NGL pipeline), and our wholesale propane logistics segment (which includes six rail terminals, two marine terminals and one pipeline terminal).

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 and its affiliates’ employees provide administrative support to us and operate most of our assets. DCP Midstream, LLC owns approximately 23% of us.

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 operations consist of a 66.67% interest in Southeast Texas and commodity derivative hedge instruments related to the Southeast Texas storage business, which we acquired from DCP Midstream, LLC in March 2012, an 80% interest in the Eagle Ford system, of which we acquired 33.33% and 46.67% in November 2012 and March 2013, respectively, from DCP Midstream, LLC, and our 100% interest in DCP Lucerne 1 Plant, LLC, a 35 MMcf/d cryogenic natural gas processing plant located in Weld County, Colorado, or the Lucerne 1 plant, which we acquired from DCP Midstream, LLC in March 2014. Prior to our acquisition of the remaining 66.67% interest in Southeast Texas, we accounted for our initial 33.33% interest as an unconsolidated affiliate using the equity method. Subsequent to the March 2012 transaction, we own 100% of Southeast Texas which we account for as a consolidated subsidiary. 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, we own 80% of the Eagle Ford system which we account 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 100% interest in Southeast Texas and the commodity derivative hedge instruments associated with the storage business, our 80% interest in the Eagle Ford system and our Lucerne 1 plant 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.

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.

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.

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.

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.

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.

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 risk free interest rate, and accretes due to the passage of time based on the time value of money until the obligation is settled.

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, 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 considered to be permanently less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Unamortized Debt Expense - Expenses incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. These 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.

Accounting for Risk Management Activities and Financial Instruments - Non-trading energy commodity derivatives are designated as either 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 period 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 period 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.

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, 2013, 2012 and 2011. 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 amounted to $1 million, and other long-term liabilities amounted to $1 million at both December 31, 2013 and 2012.

Equity-Based Compensation - Equity classified share-based compensation cost is measured at fair value, based on the closing common unit price at grant date, and is recognized as expense over the vesting period. Liability classified share-based compensation cost is remeasured at each reporting date at fair value, based on the closing common unit price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees for acquiring, or in conjunction with selling, goods and services are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

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.

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.

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.

3. Acquisitions

On March 28, 2014, we acquired the Lucerne 1 Plant from DCP Midstream, LLC and its affiliates. The Lucerne 1 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 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. Also in March 2014, DCP Midstream, LLC and its affiliates contributed or sold to us (i) the remaining 20% interest in DCP SC Texas GP; (ii) a 33.33% membership interest in each DCP Southern Hills Pipeline, LLC, which owns the Southern Hills pipeline, and DCP Sand Hills Pipeline, LLC, which owns the Sand Hills pipeline; and (iii) a 200 MMcf/d cryogenic natural gas processing plant also located in Weld County, Colorado, which is currently under construction, or the Lucerne 2 plant. The March 2014 transactions are discussed in Note 22. "Subsequent Events".

On August 5, 2013, we entered into a purchase and sale agreement with DCP Midstream, LP, or Midstream LP, a 100% owned subsidiary of DCP Midstream, LLC, pursuant to which the Partnership acquired from Midstream LP all of the membership interests in DCP LaSalle Plant LLC, or the LaSalle Transaction, for consideration of $209 million, subject to certain customary purchase price adjustments. The LaSalle Transaction was financed at closing using borrowings under our revolving credit facility.

DCP LaSalle Plant LLC owns the O'Connor plant, a cryogenic natural gas processing plant in Weld County, Colorado with initial capacity of 110 MMcf/d. Prior to the start of commercial operations in October 2013, the O'Connor plant was known as the LaSalle plant. The LaSalle Transaction represents a transfer of assets between entities under common control. The results of the O'Connor plant are included prospectively from the date of contribution in our Natural Gas Services segment. As of February 2014, the O'Connor plant expansion to 160 MMcf/d is mechanically complete.

On August 5, 2013, we entered into a purchase and sale agreement with Midstream LP pursuant to which the Partnership acquired from Midstream LP all of the membership interests in DCP Midstream Front Range LLC, or Front Range, for consideration of $86 million, subject to certain customary purchase price adjustments, or the Front Range Transaction. The Front Range Transaction was financed at closing using borrowings under our revolving credit facility.

Front Range owns a 33.33% equity interest in Front Range Pipeline LLC, a joint venture with affiliates of Enterprise Products Partners L.P., or Enterprise, and Anadarko Petroleum Corporation. The joint venture was formed to construct a new raw NGL mix pipeline that originates in the DJ Basin and extends approximately 435 miles to Skellytown, Texas, or the Front Range pipeline. With connections to the Mid-America pipeline, and to the Texas Express pipeline, in which the Partnership owns a 10% interest, the Front Range pipeline provides takeaway capacity and market access to the Gulf Coast for the expanding production of NGLs in the DJ Basin. The Front Range pipeline connects to the O'Connor plant as well as third party and DCP Midstream, LLC plants in the DJ Basin. The initial capacity of the Front Range pipeline is expected to be 150 MBbls/d, which could be expanded to 230 MBbls/d with the installation of additional pump stations. Enterprise is the operator of the pipeline, which was placed into service in February 2014. The Front Range pipeline currently has transportation agreements in place with affiliates of DCP Midstream, LLC and others. The transportation agreements provide for ship-or-pay arrangements for the first 10 years for a minimum volume specified in the agreement, with the last five years under plant dedication arrangements. The Front Range transaction represents a transfer of assets between entities under common control. The results of Front Range are included prospectively from the date of contribution in our NGL Logistics segment.

On March 28, 2013, we acquired an additional 46.67% interest in DCP SC Texas GP, or the Eagle Ford system, from DCP Midstream, LLC and an $87 million fixed price commodity derivative hedge for a three-year period for aggregate consideration of $626 million, plus customary working capital and other purchase price adjustments. $490 million of the consideration was financed with the net proceeds from our 3.875% 10-year Senior Notes offering, $125 million was financed by the issuance at closing of an aggregate 2,789,739 of our common units to DCP Midstream, LLC and the remaining $11 million was paid with cash on hand. We also reimbursed DCP Midstream, LLC $50 million for 46.67% of the capital spent to date by the Eagle Ford system for the construction of the Goliad plant, plus an incremental payment of $23 million as reimbursement for 46.67% of preformation capital expenditures. The $203 million excess purchase price over the carrying value of the acquired interest in the Eagle Ford system, as adjusted for customary working capital and other purchase price adjustments, was recorded as a decrease in limited partners’ equity. Prior to the acquisition of the additional interest in the Eagle Ford system, we owned a 33.33% interest which we accounted for as an unconsolidated affiliate using the equity method. The Eagle Ford system acquisition 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 our 80% interest in the Eagle Ford system for all periods presented, similar to the pooling method.

The assets and liabilities of our Lucerne 1 plant are included in the consolidated balance sheet as of December 31, 2013. The following table presents the previously reported December 31, 2013 consolidated balance sheet, adjusted for the acquisition of our 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)
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 assets and liabilities of our Lucerne 1 plant are included in the consolidated balance sheet as of December 31, 2012. The following table presents the previously reported December 31, 2012 consolidated balance sheet, adjusted for the acquisition of our Lucerne 1 plant from DCP Midstream, LLC:

As of 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)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 2	$ —	$ 2
Accounts receivable	239	—	239
Inventories	76	—	76
Other	51	—	51
Total current assets	368	—	368
Property, plant and equipment, net	2,550	42	2,592
Goodwill and intangible assets, net	291	—	291
Investments in unconsolidated affiliates	304	—	304
Other non-current assets	90	—	90
Total assets	$ 3,603	$ 42	$ 3,645
LIABILITIES AND EQUITY			
Accounts payable and other current liabilities	$ 345	$ —	$ 345
Long-term debt	1,620	—	1,620
Other long-term liabilities	44	—	44
Total liabilities	2,009	—	2,009
Commitments and contingent liabilities			
Equity:			
Partners’ equity			
Net equity	1,420	42	1,462
Accumulated other comprehensive loss	(15)	—	(15)
Total partners’ equity	1,405	42	1,447
Noncontrolling interests	189	—	189
Total equity	1,594	42	1,636
Total liabilities and equity	$ 3,603	$ 42	$ 3,645

The results of our Lucerne 1 plant are included in the consolidated statement of operations for the year ended December 31, 2013. The following table presents the previously reported consolidated statement of operations for the year ended December 31, 2013, adjusted for the acquisition of our 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 income	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

The results of our Lucerne 1 plant are included in the consolidated statement of operations for the year ended December 31, 2012. The following table presents the previously reported consolidated statement of operations for the year ended December 31, 2012, adjusted for the acquisition of our Lucerne 1 plant from DCP Midstream, LLC:

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

Year Ended December 31, 2011

The results of our Lucerne 1 plant are included in the consolidated statement of operations for the year ended December 31, 2011. The following table presents the previously reported consolidated statement of operations for the year ended December 31, 2011 adjusted for the acquisition of our Lucerne 1 plant from DCP Midstream, LLC:

	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	$ 3,487	$ 87	$ 3,574
Transportation, processing and other	205	3	208
Gains from commodity derivative activity, net	8	—	8
Total operating revenues	3,700	90	3,790
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	3,100	55	3,155
Operating and maintenance expense	188	4	192
Depreciation and amortization expense	133	2	135
General and administrative expense	75	1	76
Other income	(1)	—	(1)
Total operating costs and expenses	3,495	62	3,557
Operating income	205	28	233
Interest expense	(34)	—	(34)
Earnings from unconsolidated affiliates	23	—	23
Income before income taxes	194	28	222
Income tax expense	(1)	—	(1)
Net income	193	28	221
Net income attributable to noncontrolling interests	(30)	—	(30)
Net income attributable to partners	$ 163	$ 28	$ 191

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 tables present unaudited supplemental pro forma information for the consolidated statement of operations for the years ended December 31, 2012 and 2011, as if the acquisition of Crossroads had occurred at the beginning of the earliest period presented.

	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.

	Year Ended December 31, 2011		
	DCP Midstream Partners, LP	Acquisition of Crossroads	DCP Midstream Partners, LP Pro Forma
	(Millions)		
Total operating revenues	$ 3,790	$ 114	$ 3,904
Net income attributable to partners	$ 191	$ 4	$ 195
Less:			
Net income attributable to predecessor operations	(91)	—	(91)
General partner's interest in net income	(25)	—	(25)
Net income allocable to limited partners	$ 75	$ 4	$ 79
Net income per limited partner unit - basic	$ 1.73	$ 0.09	$ 1.82
Net income per limited partner unit - diluted	$ 1.72	$ 0.09	$ 1.81

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.

4. 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. Pursuant to the Services Agreement, we will reimburse DCP Midstream, LLC for expenses and expenditures incurred or payments made on our behalf.

The Services Agreement fee is subject to adjustment based on the scope of general and administrative services performed by DCP Midstream, LLC.

The following is a summary of the fees we incurred under the Services and Omnibus Agreements, as well as other fees paid to DCP Midstream, LLC:

	Year Ended December 31,		
	2013	2012	2011
		(Millions)	
Services/Omnibus Agreement	$ 29	$ 26	$ 10
Other fees — DCP Midstream, LLC	17	32	47
Total — DCP Midstream, LLC	$ 46	$ 58	$ 57

In addition to the fees paid pursuant to the Services and Omnibus Agreements, we incurred allocated expenses, including insurance and internal audit fees with DCP Midstream, LLC of $2 million for the year ended December 31, 2013 and $1 million for each of the years ended December 31, 2012 and 2011, respectively. The Lucerne 1 plant incurred $1 million in general and administrative expenses directly from DCP Midstream, LLC for each of the years ended December 31, 2013, 2012 and 2011. The Eagle Ford system incurred $14 million for the year ended December 31, 2013 and $27 million for each of the years ended December 31, 2012 and 2011, respectively, in general and administrative expenses directly from DCP Midstream, LLC. For the years ended December 31, 2012 and 2011, Southeast Texas incurred $3 million and $10 million in general and administrative expenses directly from DCP Midstream, LLC, before the addition of Southeast Texas to the Omnibus Agreement in March 2012. During the year ended December 31, 2011, East Texas incurred $8 million in general and administrative expenses directly from DCP Midstream, 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.

Other Agreements and Transactions with DCP Midstream, LLC

DCP Midstream, LLC was a significant customer during the years ended December 31, 2013, 2012 and 2011. 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, $5 million and $18 million for the years ended December 31, 2013, 2012, and 2011 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 plant, we entered into a 15-year fee-based processing agreement with an affiliate of DCP Midstream, LLC pursuant to which such affiliate 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 such affiliate at the O'Connor plant. Under this agreement, we received fees of $6 million during the year ended December 31, 2013, which are included in transportation, processing and other to affiliates in the consolidated statements of operations.

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.

During the year ended December 31, 2011, East Texas received $8 million in business interruption recoveries related to the first quarter 2009 fire that was caused by a third party underground pipeline rupture outside of our property, or the East Texas recovery settlement. We have allocated the recoveries based upon relative ownership percentages at the time the losses were incurred, factoring in amounts previously reimbursed to us by DCP Midstream, LLC. For the year ended December 31, 2011, we recorded $7 million to sales of natural gas, propane, NGLs and condensate, with $5 million representing DCP Midstream, LLC’s portion recorded in net income attributable to noncontrolling interests, in the consolidated statement of operations.

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 Texas Express Pipeline has in place a long-term, fee-based, ship-or-pay transportation agreement with DCP Midstream, LLC of 20 MBbls/d.

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.

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 incurred fees of $1 million and less than $1 million during the years ended December 31, 2013 and 2012, respectively, which are included in operating and maintenance expense in the consolidated statements of operations.

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,		
	2013	**2012**	**2011**
		(Millions)	
DCP Midstream, LLC:			
Sales of natural gas, propane, NGLs and condensate	$ 1,830	$ 1,691	$ 2,346
Transportation, processing and other	$ 60	$ 52	$ 30
Purchases of natural gas, propane and NGLs	$ 204	$ 173	$ 244
Gains from commodity derivative activity, net	$ 22	$ 53	$ 1
Operating and maintenance expense	$ 1	$ 1	$ 1
General and administrative expense	$ 46	$ 58	$ 57
Phillips 66:			
Sales of natural gas, propane, NGLs and condensate	$ 1	$ —	$ —
ConocoPhillips (a):			
Sales of natural gas, propane, NGLs and condensate	$ —	$ 9	$ 57
Transportation, processing and other	$ —	$ 3	$ 9
Purchases of natural gas, propane and NGLs	$ —	$ 67	$ 139
Spectra Energy:			
Purchases of natural gas, propane and NGLs	$ 63	$ 166	$ 321
Unconsolidated affiliates:			
Purchases of natural gas, propane and NGLs	$ —	$ 2	$ 6

(a) In connection with Phillips 66's separation from ConocoPhillips, ConocoPhillips is not considered to be a related party for periods after April 30, 2012 and Phillips 66 is considered a related party for periods starting May 1, 2012.

We had balances with affiliates as follows:

	December 31, 2013	December 31, 2012
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 211	$ 132
Accounts payable	$ 37	$ 66
Unrealized gains on derivative instruments — current	$ 79	$ 48
Unrealized gains on derivative instruments — long-term	$ 81	$ 64
Unrealized losses on derivative instruments — current	$ 18	$ (11)
Unrealized losses on derivative instruments — long-term	$ 1	$ —
Spectra Energy:		
Accounts receivable	$ 1	$ —
Accounts payable	$ 6	$ 5
Unconsolidated affiliates:		
Accounts payable	$ —	$ 1

5. Inventories

Inventories were as follows:

	December 31, 2013	December 31, 2012
	(Millions)	
Natural gas	$ 38	$ 22
NGLs	29	54
Total inventories	$ 67	$ 76

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 $4 million and $19 million in lower of cost or market adjustments during the years ended December 31, 2013 and 2012, respectively.

6. Property, Plant and Equipment

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

	Depreciable Life	December 31, 2013	December 31, 2012
		(Millions)	
Gathering and transmission systems	20 — 50 Years	$ 2,205	$ 1,921
Processing, storage, and terminal facilities	35 — 60 Years	1,645	1,154
Other	3 — 30 Years	49	32
Construction work in progress		310	561
Property, plant and equipment		4,209	3,668
Accumulated depreciation		(1,163)	(1,076)
Property, plant and equipment, net		$ 3,046	$ 2,592

Interest capitalized on construction projects in 2013, 2012 and 2011 was $11 million, $7 million and $2 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 $87 million, $83 million, and $127 million for the years ended December 31, 2013, 2012, and 2011, respectively.

During the year ended December 31, 2013, we discontinued certain construction projects and wrote off approximately $8 million in construction work in progress to other expense in the consolidated statements of operations.

Asset Retirement Obligations - As of December 31, 2013 and 2012, we had asset retirement obligations of $24 million and $23 million, respectively, included in other long-term liabilities in the consolidated balance sheets. Accretion expense was $1 million for each of the years ended December 31, 2013 and 2011 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.

7. Goodwill and Intangible Assets

The carrying value of goodwill as of December 31, 2013 and December 31, 2012 was $154 million for each of the periods, 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 the components of our operating segments constitute businesses for which discrete financial information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. As a result of our assessment, we concluded that the fair value of goodwill substantially exceeded its carrying value 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.

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,	
	2013	2012
	(Millions)	
Gross carrying amount	$ 164	$ 164
Accumulated amortization	(35)	(27)
Intangible assets, net	$ 129	$ 137

For each of the years ended December 31, 2013, 2012, and 2011, we recorded amortization expense of $8 million. As of December 31, 2013, the remaining amortization periods ranged from approximately 8 years to 22 years, with a weighted-average remaining period of approximately 17 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization
	(Millions)
2014	$ 8
2015	8
2016	8
2017	8
2018	8
Thereafter	89
Total	$ 129

8. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of December 31, 2013	Carrying Value as of December 31, 2012
		(Millions)	
Discovery Producer Services LLC	40%	$ 348	$ 223
Front Range Pipeline LLC	33.33%	134	—
Texas Express Pipeline	10%	96	41
Mont Belvieu Enterprise Fractionator	12.5%	26	19
Mont Belvieu 1 Fractionator	20%	16	14
CrossPoint Pipeline, LLC	50%	6	6
Other	Various	1	1
Total investments in unconsolidated affiliates		$ 627	$ 304

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $28 million and $30 million at December 31, 2013 and December 31, 2012, 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 Front Range of $4 million at December 31, 2013, which is associated with interest capitalized during the construction of the pipeline and will be 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 and less than $1 million at December 31, 2013 and December 31, 2012, 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 $5 million and $6 million at December 31, 2013 and December 31, 2012, respectively, which is associated with, and is being amortized over the life of the underlying long-lived assets of Mont Belvieu 1.

Earnings from investments in unconsolidated affiliates were as follows:

	Year Ended December 31,		
	2013	2012	2011
		(Millions)	
Mont Belvieu 1 Fractionator	$ 19	$ 6	$ —
Mont Belvieu Enterprise Fractionator	14	5	—
Discovery Producer Services LLC	1	15	23
Texas Express	(1)	—	—
Total earnings from unconsolidated affiliates	$ 33	$ 26	$ 23

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

	Year Ended December 31,		
	2013	2012	2011
		(Millions)	
Statements of operations:			
Operating revenue	$ 484	$ 293	$ 213
Operating expenses	$ 298	$ 190	$ 163
Net income	$ 186	$ 103	$ 50

	December 31, 2013	December 31, 2012
	(Millions)	
Balance sheets:		
Current assets	$ 182	$ 129
Long-term assets	2,678	1,288
Current liabilities	(276)	(75)
Long-term liabilities	(37)	(43)
Net assets	$ 2,547	$ 1,299

9. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an “exit price” methodology, in line with how we believe a marketplace participant would value that asset or liability. Fair values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, 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 11 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 input that requires the highest degree of judgment 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 use interest rate swap agreements as part of our overall capital strategy. These instruments 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 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, 2013 and December 31, 2012, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets (a):								
Commodity derivatives	$ —	$ 14	$ 65	$ 79	$ —	$ 9	$ 40	$ 49
Short-term investments (b)	$ 9	$ —	$ —	$ 9	$ 2	$ —	$ —	$ 2
Long-term assets (c):								
Commodity derivatives	$ —	$ 12	$ 75	$ 87	$ —	$ 5	$ 65	$ 70
Current liabilities (d):								
Commodity derivatives	$ —	$ (26)	$ —	$ (26)	$ —	$ (26)	$ (1)	$ (27)
Interest rate derivatives	$ —	$ (2)	$ —	$ (2)	$ —	$ (4)	$ —	$ (4)
Long-term liabilities (e):								
Commodity derivatives	$ —	$ (1)	$ —	$ (1)	$ —	$ (6)	$ —	$ (6)
Interest rate derivatives	$ —	$ —	$ —	$ —	$ —	$ (2)	$ —	$ (2)

(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 between Level 1 and Level 2 would be reflected in a table as Transfers in/out of Level 1/Level 2. During the years ended December 31, 2013 and 2012, there were no transfers between Level 1 and Level 2 of the fair value hierarchy.

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our 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” caption.

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, 2013 (a):				
Beginning balance	$ 40	$ 65	$ (1)	$ —
Net realized and unrealized gains (losses) included in earnings (c)	42	(50)	—	—
Transfers into Level 3 (b)	—	—	—	
Transfers out of Level 3 (b)	(1)	(2)	1	—
Settlements	(40)	—	—	—
Purchases	24	62	—	—
Ending balance	$ 65	$ 75	$ —	$ —
Net unrealized gains (losses) still held included in earnings (c)	$ 41	$ (50)	$ —	$ —
Year ended December 31, 2012 (a):				
Beginning balance	$ 1	$ 1	$ (1)	$ —
Net realized and unrealized gains included in earnings (c)	14	2	—	—
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	—	—	—	—
Settlements	(2)	—	—	—
Purchases	27	62	—	—
Ending balance	$ 40	$ 65	$ (1)	$ —
Net unrealized gains still held included in earnings (c)	$ 13	$ 2	$ —	$ —

(a) There were no issuances or sales of derivatives for the years ended December 31, 2013 and 2012.
(b) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(c) Represents the amount of total gains or losses for the year, 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, 2013		
Product Group	Fair Value	Forward Curve Range	
	(Millions)		
Assets			
NGLs	$ 140	$0.27-$2.11	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 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, 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.

The carrying value of outstanding balances under our Credit Agreement was $525 million as of December 31, 2012, which approximated fair value.

The carrying and fair values of the 3.875% Senior Notes were $494 million and $461 million, respectively, as of December 31, 2013.

The carrying and fair values of the 2.50% Senior Notes was $497 million and $500 million as of December 31, 2013. The carrying value as of December 31, 2012 was $500 million, which approximated fair value.

The carrying and fair values of the 4.95% Senior Notes was $349 million and $354 million, respectively as of December 31, 2013, and $350 million and $374 million, respectively, as of December 31, 2012.

The carrying and fair values of the 3.25% Senior Notes were $250 million and $258 million, respectively, as of December 31, 2013, and $250 million and $259 million, respectively, as of December 31, 2012.

We determine the fair value of our Credit Agreement borrowings based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We 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.

10. Debt

	December 31, 2013	December 31, 2012
	(Millions)	
Commercial Paper		
Short-term borrowings, weighted-average interest rate of 1.14%	$ 335	$ —
Credit Agreement		
Revolving credit facility, weighted-average variable interest rate of 1.47%, as of December 31, 2012, due November 10, 2016 (a)	—	525
Debt Securities		
Issued March 14, 2013, interest at 3.875% payable semi-annually, due March 15, 2023	500	—
Issued November 27, 2012, interest at 2.50% payable semi-annually, due December 1, 2017	500	500
Issued March 13, 2012, interest at 4.95% payable semi-annually, due April 1, 2022	350	350
Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015	250	250
Unamortized discount	(10)	(5)
Total debt	1,925	1,620
Short-term borrowings	(335)	—
Total long-term debt	$ 1,590	$ 1,620

(a) $150 million was swapped to a fixed rate obligation with fixed rates ranging from 2.94% to 2.99%, for a net effective rate of 2.25% on the $525 million of outstanding debt under our revolving credit facility as of December 31, 2012.

Commercial Paper Program

In October 2013, we entered into a commercial paper program, or the Commercial Paper Program, under which we may issue unsecured commercial paper notes, or the Notes. The Commercial Paper Program serves 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 revolving credit facility, not to exceed $1 billion in the aggregate. Amounts undrawn under our revolving credit facility 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, 2013, we had $335 million of commercial paper outstanding, which is included in short-term borrowings in our consolidated balance sheets.

Credit Agreement

We have a $1 billion revolving credit facility that matures November 10, 2016, or the Credit Agreement.

At December 31, 2013 and 2012, we had $1 million of letters of credit issued and outstanding under the Credit Agreement. As of December 31, 2013, the unused capacity under the Credit Agreement was $664 million, net of amounts outstanding under our Commercial Paper Program and letters of credit, which was available for general working capital purposes.

Our borrowing capacity may be limited by the Credit Agreement’s financial covenant requirements. Except in the case of a default, amounts borrowed under our Credit Agreement will not become due prior to the November 10, 2016 maturity date.

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. Under the Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) LIBOR, plus an applicable margin of 1.25% 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 0.25% based on our current credit rating. The revolving credit facility incurs an annual facility fee of 0.25% based on our current credit rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

The 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.

Debt Securities

On March 14, 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 of $10 million, 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 will be 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.

On November 27, 2012, we issued $500 million of our 2.50% 5-year Senior Notes due December 1, 2017. We received net proceeds of $494 million, net of underwriters' fees, related expenses and unamortized discounts of $6 million. Interest on the notes will be paid semi-annually on June 1 and December 1 of each year, commencing June 1, 2013. The notes will mature on December 1, 2017, unless redeemed prior to maturity.

On March 13, 2012, we issued $350 million of our 4.95% 10-year Senior Notes due April 1, 2022. We received net proceeds of $346 million, net of underwriters' fees, related expenses and unamortized discounts of $4 million, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Agreement. Interest on the notes is paid semi-annually on April 1 and October 1 of each year. The notes will mature on April 1, 2022, unless redeemed prior to maturity.

On September 30, 2010, we issued $250 million of our 3.25% Senior Notes due October 1, 2015. We received net proceeds of $248 million, net of underwriters' fees, related expense and unamortized discounts of $2 million, which we used to repay funds borrowed under the revolver portion of our Credit Agreement. Interest on the notes is paid semi-annually on April 1 and October 1 of each year. The notes will mature on October 1, 2015, 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 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)
2014	$ —
2015	250
2016	—
2017	500
2018	—
Thereafter	850
	1,600
Unamortized discount	(10)
Total	$ 1,590

11. 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 significant 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 2017 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 2011, Southeast Texas commenced an expansion project to build an additional storage cavern. To mitigate risk associated with the forecasted purchase of natural gas, we executed a series of derivative financial instruments, which were designated as cash flow hedges. During the second half of 2013, Southeast Texas purchased base gas to bring the storage cavern to operation. The balance in accumulated other comprehensive income, or AOCI, of these cash flow hedges was in a loss position of $3 million as of December 31, 2013. While the cash paid upon settlement of these hedges economically fixed the cash required to purchase the base gas, the deferred loss will remain in AOCI until the cavern is emptied and the base gas is sold.

Interest Rate Risk

At December 31, 2013, we had interest rate swap agreements extending 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 pay fixed-rates ranging from 2.94% to 2.99%, and receive 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. The deferred loss in AOCI of $3 million, at the time of de-designation, will be reclassified into earnings as the hedged transactions impact earnings.

In March 2012, we settled $195 million of our forward-starting interest rate swap agreements for $7 million. The net deferred losses in AOCI of $5 million, at the settlement date, will be amortized into interest expense associated with our long-term debt offering through 2022.

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 Swap Dealers Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- If we were to have an effective event of default under our Credit Agreement that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.
- In the event that we or DCP Midstream, LLC were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties 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 those agreements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Credit Agreement. As of December 31, 2013, we are not a party to any agreements that would be subject to these provisions other than our Credit Agreement.

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, 2013, we had $8 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any cash collateral relative to such positions. 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, 2013, if a credit-risk related event were to occur we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2013, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $6 million.

As of December 31, 2013, we had $150 million of interest rate swap instruments that were in a net liability position of $2 million and were subject to credit-risk related contingent features. If we were to have a default of any of our covenants to our Credit Agreement that occurs and is continuing, the counterparties to our swap instruments have the right to request that we net settle the instrument in the form of cash.

Unconsolidated Affiliates

Discovery Producer Services LLC, 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, 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:

	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
	December 31, 2013			December 31, 2012		
Assets:						
Commodity derivatives	$ 166	$ (13)	$ 153	$ 119	$ (10)	$ 109
Interest rate derivatives	$ —	$ —	$ —	$ —	$ —	$ —
Liabilities:						
Commodity derivatives	$ (27)	$ 13	$ (14)	$ (33)	$ 10	$ (23)
Interest rate derivatives	$ (2)	$ —	$ (2)	$ (6)	$ —	$ (6)

(a) There is no cash collateral pledged or received against these positions.

Summarized Derivative Information

The fair value of our derivative instruments that are designated as hedging instruments and those that are marked-to-market each period, as well as the location of each within our consolidated balance sheets, by major category, is summarized as follows:

Balance Sheet Line Item	December 31, 2013	December 31, 2012	Balance Sheet Line Item	December 31, 2013	December 31, 2012
	(Millions)			(Millions)	
Derivative Assets Designated as Hedging Instruments:			**Derivative Liabilities Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments — current	$ —	$ —	Unrealized losses on derivative instruments — current	$ —	$ (3)
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	—
	$ —	$ —		$ —	$ (3)
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments — current	$ —	$ —	Unrealized losses on derivative instruments — current	$ —	$ (4)
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	(2)
	$ —	$ —		$ —	$ (6)
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments — current	$ 79	$ 49	Unrealized losses on derivative instruments — current	$ (26)	$ (24)
Unrealized gains on derivative instruments — long-term	87	70	Unrealized losses on derivative instruments — long-term	(1)	(6)
	$ 166	$ 119		$ (27)	$ (30)
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, 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) gains in AOCI (ending balance)	$ (6)		$ (6)	$ 1	$ (11)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ (2)		$ —	$ —	$ (2)

(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 were reclassified from AOCI to earnings from unconsolidated affiliates 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.

The following table summarizes the impact on our consolidated balance sheet and consolidated statements of operations of our derivative instruments that are accounted for using the cash flow hedge method of accounting for the year ended December 31, 2012:

	(Losses) gains Recognized in AOCI on Derivatives — Effective Portion	Losses Reclassified From AOCI to Earnings — Effective Portion		Losses Recognized in Income on Derivatives — Ineffective Portion and Amount Excluded From Effectiveness Testing	
	(Millions)				
Interest rate derivatives	$ (1)	$ (10)	(a)	$ (2)	(a) (b)
Commodity derivatives	$ (1)	$ —		$ —	
Foreign currency derivatives (c)	$ 1	$ —		$ —	

(a) Included in interest expense in our consolidated statements of operations.
(b) For the year ended December 31, 2012, less than $1 million of derivative losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.
(c) Relates to Discovery, our unconsolidated affiliate.

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, 2013	2012	2011
	(Millions)		
Third party:			
Realized (losses) gains	$ (19)	$ 4	$ (36)
Unrealized gains	14	13	43
(Losses) gains from commodity derivative activity, net	$ (5)	$ 17	$ 7
Affiliates:			
Realized gains	$ 73	$ 45	$ 2
Unrealized (losses) gains	(51)	8	(1)
Gains from commodity derivative activity, net —affiliates	$ 22	$ 53	$ 1

Interest Rate Derivatives: Statements of Operations Line Item	Year Ended December 31, 2013	2012	2011
	(Millions)		
Third party:			
Realized losses	$ (2)	$ (7)	$ (4)
Unrealized gains	2	7	5
Interest expense	$ —	$ —	$ 1

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, 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)	—

	December 31, 2012			
	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 (Short) Position (Mmbtu)
2013	(943,379)	(8,887,980)	(2,593,955)	9,690,000
2014	(584,365)	(4,712,880)	(2,584,930)	(1,350,000)
2015	(401,865)	(5,127,155)	(2,491,250)	—
2016	(183,000)	—	—	—

We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of December 31, 2013, we have swaps with a notional value of $70 million and $80 million, which, in aggregate, exchange $150 million of our floating rate obligation to a fixed rate obligation through June 2014.

12. Partnership Equity and Distributions

General — During the year ended December 31, 2013, we issued 1,408,547 of our common units pursuant to an equity distribution agreement entered into in August 2011, or the 2011 equity distribution agreement. We received proceeds of $67 million, net of commissions and offering costs of $2 million, which were used to finance growth opportunities and for general partnership purposes. The 2011 equity distribution agreement provided for the offer and sale of common units having an aggregate offering amount of up to $150 million. As of December 31, 2013, no common units remain available for sale pursuant to this equity distribution agreement and we have deregistered the corresponding registration statement.

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 June 2013, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of $300 million, which became effective on June 27, 2013. The shelf registration statement allows us to issue additional common units. 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 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 $300 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 accrued commissions and offering costs of $1 million, which were used to finance growth opportunities and for general partnership purposes. As of December 31, 2013, approximately $212 million of the aggregate offering amount remains available for sale pursuant to the 2013 equity distribution agreement.

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 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 March 2011, we issued 3,596,636 common units at $40.55 per unit. We received proceeds of $140 million, net of offering costs.

In February 2011, we issued 8,399 common units, from our LTIP to employees as compensation for their service during 2010, 2009 and 2008.

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 1% and limited partner interest of 1% as of December 31, 2013. 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 2013, 2012 and 2011:

Payment Date	Per Unit Distribution	Total Cash Distribution
		(Millions)
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
November 14, 2011	$ 0.6400	$ 35
August 12, 2011	$ 0.6325	$ 34
May 13, 2011	$ 0.6250	$ 33
February 14, 2011	$ 0.6175	$ 30

13. Equity-Based Compensation

Total compensation cost for equity-based arrangements was as follows:

	Year Ended December 31,		
	2013	2012	2011
	(Millions)		
Performance Phantom Units	$ 1	$ 1	$ 5
Phantom Units	—	—	—
Restricted Phantom Units	1	1	2
Total compensation cost	$ 2	$ 2	$ 7

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. 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 the grant of DERs. The phantom units consist of a notional unit based on the value of common units or shares of the Partnership, 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. All awards are subject to cliff vesting.

Prior to February 18, 2011, substantially all equity-based awards were accounted for as liability awards. Effective February 18, 2011, the Modification Date, we have the intent and ability to settle certain awards within our control in units and therefore modified the accounting for these awards. We classified them as equity awards based on their re-measured fair value. The fair value was determined based on the closing price of our common units on the Modification Date. Such modification resulted in a reclassification of $2 million from share-based compensation liability to additional paid-in capital on the Modification Date. Compensation expense on unvested equity awards as of the Modification Date is recognized ratably over each remaining vesting period.

We account for other awards, which are subject to settlement in cash, 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.

The reclassification of the affected awards did not impact our accounting for dividend equivalent rights as these instruments will continue to be settled in cash and therefore retain their share-based compensation liability classification.

Performance Phantom Units - We have awarded Performance Phantom Units, or PPUs, pursuant to the LTIP to certain employees. PPUs generally vest in their entirety at the end of a three year performance period. The number of PPUs that will ultimately vest range, in value up to 200% of the outstanding PPUs, depending on the achievement of specified performance targets over three year performance periods. The final performance payout is determined by the board of directors of our General Partner. The DERs are paid in cash at the end of the performance period. Of the remaining PPUs outstanding at December 31, 2013, 2,070 units are expected to vest on December 31, 2014 and 10,890 units are expected to vest on December 31, 2015.

At December 31, 2013, there was less than $1 million of unrecognized compensation expense related to the PPUs that is expected to be recognized over a weighted-average period of approximately 2 years. The following table presents information related to the PPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2011	67,350	$ 15.42	
Granted	10,580	$ 41.80	
Vested	(50,720)	$ 10.05	
Forfeited	—	$ —	
Outstanding at December 31, 2011	27,210	$ 35.69	
Granted (a)	11,740	$ 39.31	
Vested	(20,100)	$ 34.57	
Forfeited	(7,760)	$ 38.97	
Outstanding at December 31, 2012	11,090	$ 39.24	
Granted	11,450	$ 40.88	
Vested (b)	(3,800)	$ 40.75	
Forfeited	(4,990)	$ 38.77	
Outstanding at December 31, 2013	13,750	$ 40.36	$ 50.33
Expected to vest (c)	12,960	$ 40.38	$ 50.33

(a) Includes the impact of conversion of the underlying securities, in connection with Phillip 66's separation from ConocoPhillips, granted under the 2012 LTIP.
(b) The units vested at 150%.
(c) Based on our December 31, 2013 estimated achievement of specified performance targets, the performance estimate for units granted in both 2013 and 2012 is 100%. The estimated forfeiture rate for units granted in both 2013 and 2012 is 10%.

The estimate of PPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

The following table presents the fair value of units vested and the unit-based liabilities paid related to PPUs, including the related DERs:

	Year Ended December 31,		
	2013	2012	2011
	(Millions)		
Fair value of units vested	less than $1	$ 1	$ 5
Unit-based liabilities paid	$ 1	$ 5	$ —

Phantom Units - As part of their director fees, we granted 4,400 Phantom Units to directors during the year ended December 31, 2013 and 4,000 Phantom Units to directors during each of the years ended December 31, 2012, and 2011, respectively. All of these units vested in their respective grant years, and were settled in units. The DERs are paid in cash quarterly in arrears. The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2011	—	$ —	
Granted	4,000	$ 41.80	
Vested	(4,000)	$ 41.80	
Outstanding at December 31, 2011	—	$ —	
Granted	4,000	$ 48.03	
Vested	(4,000)	$ 48.03	
Outstanding at December 31, 2012	—	$ —	
Granted	4,400	$ 46.39	
Vested	(4,400)	$ 46.39	
Outstanding at December 31, 2013	—	$ —	$ —

The fair value of units vested related to Phantom Units was less than $1 million for each of the years ended December 31, 2013, 2012 and 2011.

Restricted Phantom Units - Our General Partner’s board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. Of the remaining RPUs outstanding at December 31, 2013, 2,070 units are expected to vest on December 31, 2014 and 11,281 units are expected to vest on December 31, 2015. The DERs are paid in cash quarterly in arrears. At December 31, 2013, there was less than $1 million of unrecognized compensation expense related to the RPUs that is expected to be recognized over a weighted-average period of approximately 2 years. The following table presents information related to the RPUs:

	Units	Grant Date Weighted-Average Price per Unit		Measurement Date Price per Unit	
Outstanding at January 1, 2011	67,350	$	15.42		
Granted	10,580	$	41.80		
Vested	(58,600)	$	12.97		
Forfeited	—	$	—		
Outstanding at December 31, 2011	19,330	$	37.27		
Granted (a)	11,740	$	39.31		
Vested	(19,060)	$	37.31		
Forfeited	(7,760)	$	43.27		
Outstanding at December 31, 2012	4,250	$	39.63		
Granted	11,590	$	41.94		
Vested	(1,950)	$	41.80		
Forfeited	—	$	—		
Outstanding at December 31, 2013	13,890	$	41.25	$	50.33
Expected to vest	13,351	$	41.38	$	50.30

(a) Includes the impact of conversion of the underlying securities, in connection with Phillip 66's separation from ConocoPhillips, granted under the 2012 LTIP.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to Restricted Phantom Units:

	Year Ended December 31,					
	2013		2012		2011	
	(Millions)					
Fair value of units vested		less than $1	$	1	$	3
Unit-based liabilities paid	$	1	$	2	$	1

The estimate of RPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate, which was estimated at 10% for units granted in both 2013 and 2012. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

14. 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 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 Performance Units, Phantom Units and Restricted Units. The dilutive effect of unit-based awards was 19,179, 33,043 and 64,286 equivalent units during the years ended December 31, 2013, 2012 and 2011, respectively.

15. 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, 2013 and 2012.

In December 2010, we acquired all of the interests in Marysville Hydrocarbons Holdings, LLC, an entity that owned a taxable C-Corporation consolidated return group. We estimated $35 million of deferred tax liabilities resulting from built-in tax gains recognized in the transaction and recorded this as part of our preliminary acquisition accounting as of December 31, 2010. In January 2011, we merged two 100% owned subsidiaries of Marysville Hydrocarbons Holding, LLC and converted the combined entity's organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggered the deferred tax liabilities resulting from built-in tax gains to become currently payable. Accordingly, the estimated $35 million of deferred tax liabilities at December 31, 2010 became currently payable on January 4, 2011. During 2011, we made federal and state tax payments of $29 million and less than $1 million, respectively, related to our estimated $35 million tax liability that resulted from our acquisition of Marysville. In 2011, the remaining $5 million estimated tax payable was reclassified to goodwill in our final acquisition accounting for the Marysville business combination.

The State of Texas imposes a margin tax that is assessed at 0.975% of taxable margin apportioned to Texas for the year ended December 31, 2013 and 1% for the years ended December 31, 2012 and 2011. For the year ended December 31, 2011, the state of Michigan imposed a business tax of 0.8% on gross receipts and 4.95% of Michigan taxable income. The sum of the gross receipts and income tax was subject to a tax surcharge of 21.99%. The Michigan business tax was repealed beginning with the year ended December 31, 2012.

Income tax expense consists of the following:

	Year Ended December 31,		
	2013	**2012**	**2011**
		(Millions)	
Current:			
Federal income tax expense	$ —	$ —	$ (29)
State income tax expense	(3)	(1)	(2)
Deferred:			
Federal income tax benefit	—	—	29
State income tax (expense) benefit	(5)	—	1
Total income tax expense	$ (8)	$ (1)	$ (1)

We had net long-term deferred tax liabilities of $11 million and $6 million as of December 31, 2013 and 2012, 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.

16. Commitments and Contingent Liabilities

Litigation

Prospect — In 2011, we received an arbitration claim, or the Claim, filed with the American Arbitration Association by Prospect Street Energy, LLC and Prospect Street Ventures I, LLC, or together, the Claimants, against EE Group, LLC, or EE Group, and a number of other parties that previously owned, directly or indirectly, our Marysville NGL storage facility, or collectively, the Respondents. EE Group is our indirect subsidiary which we acquired in connection with our acquisition of Marysville Hydrocarbons Holdings, LLC, or Marysville, on December 30, 2010. The Claim involves actions taken and time periods prior to our ownership of EE Group and Marysville, and includes several causes of action including claims of civil conspiracy, breach of fiduciary duty and fraud. As of February 2014, we have entered into separate settlement agreements with the Claimants and the other Respondents involved in the arbitration. We believe these settlement agreements substantially mitigate our liability in this matter and therefore, we consider this matter closed.

Other — We are not a party to any other 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 and July 2013 for the 2013-2014 insurance year. We contract with third party and affiliate 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 or our limits in the 2013-2014 insurance year compared with the 2012-2013 insurance year. We are jointly insured with DCP Midstream, LLC for a portion of the directors and officers 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 2013-2014 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 as a result of higher industry-wide damage claims. Additionally, the named windstorm property and business interruption insurance that is available comes at uneconomic premium levels, higher deductibles and lower coverage limits. As such, Discovery continues to elect not to purchase offshore named windstorm property and business interruption insurance coverage for the 2013-2014 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 United States 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. Failure to comply with these 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 $17 million, $14 million, and $15 million for the years ended December 31, 2013, 2012, and 2011, 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, 2013:

		(Millions)
2014	$	16
2015		14
2016		12
2017		10
2018		9
Thereafter		33
Total minimum rental payments	$	94

17. 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.

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 80% interest in the Eagle Ford system, 100% owned Eagle Plant, East Texas system, Southeast Texas system, Michigan system, Northern Louisiana system, Southern Oklahoma system, Wyoming system, 75% interest in the Piceance system, 40% interest in Discovery, and the DJ Basin system.

NGL Logistics — Our NGL Logistics segment provides services that include transportation, storage and fractionation of NGLs. The segment consists of the NGL storage facility in Michigan, our 20% interest in the Mont Belvieu 1 fractionator, our 12.5% interest in the Mont Belvieu Enterprise fractionator, the Black Lake and Wattenberg interstate NGL pipelines, the DJ Basin NGL fractionators in Colorado, the Seabreeze and Wilbreeze intrastate NGL pipelines, our 33.33% interest in the Front Range interstate NGL pipeline, and our 10% interest in the Texas Express intrastate NGL pipeline.

Wholesale Propane Logistics — Our Wholesale Propane Logistics segment provides services that include the receipt of propane by pipeline, rail or ship to our terminals that store and deliver the product to distributors. The segment consists of six 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 business of each segment.

The following tables set forth our segment information:

Year Ended December 31, 2013:

	Natural Gas Services (d)	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 (b)	—	—	—	(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 (c)	$ (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 (d)	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 (b)	—	—	—	(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 (c)	$ 20	$ —	$ 1	$ —	$ 21
Capital expenditures	$ 468	$ 12	$ 4	$ —	$ 484
Acquisitions net of cash acquired	$ 715	$ 30	$ —	$ —	$ 745
Investments in unconsolidated affiliates	$ 115	$ 43	$ —	$ —	$ 158

Year Ended December 31, 2011:

	Natural Gas Services (d)	NGL Logistics	Wholesale Propane Logistics	Other	Eliminations (f)	Total
				(Millions)		
Total operating revenue	$ 3,102	$ 57	$ 633	$ —	$ (2)	$ 3,790
Gross margin (a)	$ 532	$ 52	$ 51	$ —	$ —	$ 635
Operating and maintenance expense	(161)	(16)	(15)	—	—	(192)
Depreciation and amortization expense	(124)	(8)	(3)	—	—	(135)
General and administrative expense	—	—	—	(76)	—	(76)
Earnings from unconsolidated affiliates	23	—	—	—	—	23
Other operating income	—	1	—	—	—	1
Interest expense	—	—	—	(34)	—	(34)
Income tax expense (b)	—	—	—	(1)	—	(1)
Net income (loss)	270	29	33	(111)	—	221
Net income attributable to noncontrolling interests	(30)	—	—	—	—	(30)
Net income (loss) attributable to partners	$ 240	$ 29	$ 33	$ (111)	$ —	$ 191
Non-cash derivative mark-to-market (c)	$ 42	$ —	$ —	$ (2)	$ —	$ 40
Capital expenditures	$ 372	$ 9	$ 4	$ —	$ —	$ 385
Acquisitions net of cash acquired	$ 122	$ 30	$ —	$ —	$ —	$ 152
Investments in unconsolidated affiliates	$ 8	$ —	$ —	$ —	$ —	$ 8

	December 31,		
	2013	2012	2011
	(Millions)		
Segment long-term assets:			
Natural Gas Services (d)	$ 3,303	$ 2,748	$ 2,214
NGL Logistics	555	340	250
Wholesale Propane Logistics	106	105	104
Other (e)	100	84	14
Total long-term assets	4,064	3,277	2,582
Current assets (d)	503	368	373
Total assets	$ 4,567	$ 3,645	$ 2,955

(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) For the year ended December 31, 2011, income tax expense relates primarily to the Texas margin tax and the Michigan business tax. The Michigan business tax was repealed in 2012; accordingly, income tax expense for the years ended December 31, 2013 and 2012 relates primarily to the Texas margin tax.

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

(d) The segment information as of and for the years ended December 31, 2013, 2012 and 2011, includes the results of our Lucerne 1 plant, our 80% interest in the Eagle Ford system and our 100% interest in Southeast Texas. Transfers of net assets between entities under common control 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.

(e) Other long-term assets not allocable to segments consist of unrealized gains on derivative instruments, corporate leasehold improvements and other long-term assets.

(f) Represents intersegment revenues consisting of sales of NGLs by Marysville in our NGL Logistics segment to our Wholesale Propane Logistics segment.

18. Supplemental Cash Flow Information

	Year Ended December 31,		
	2013	2012	2011
	(Millions)		
Cash paid for interest and income taxes:			
Cash paid for interest, net of amounts capitalized	$ 40	$ 23	$ 17
Cash paid for income taxes, net of income tax refunds	$ 1	$ 1	$ 30
Non-cash investing and financing activities:			
Property, plant and equipment acquired with accounts payable	$ 27	$ 47	$ 34
Other non-cash additions of property, plant and equipment	$ 1	$ 8	$ 3
Non-cash change in parent advances	$ —	$ (115)	$ 5
Accounts payable related to equity issuance costs	$ 1	$ —	$ —

19. Quarterly Financial Data (Unaudited)

Our consolidated results of operations by quarter for the years ended December 31, 2013 and 2012 were as follows (millions, except per unit amounts):

2013	First (a)	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 (loss) 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 all periods presented.

2012	First (a)	Second (a)	Third (a)	Fourth (a)	Year Ended December 31, 2012 (a)
Total operating revenues	$ 855	$ 680	$ 618	$ 671	$ 2,824
Operating income	$ 52	$ 99	$ 13	$ 82	$ 246
Net income	$ 44	$ 90	$ 14	$ 81	$ 229
Net income attributable to noncontrolling interests	$ (4)	$ (2)	$ (2)	$ (5)	$ (13)
Net income attributable to partners	$ 40	$ 88	$ 12	$ 76	$ 216
Net income (loss) allocable to limited partners	$ 12	$ 69	$ (9)	$ 52	$ 124
Basic and diluted net income (loss) per limited partner unit	$ 0.26	$ 1.33	$ (0.16)	$ 0.87	$ 2.28

(a) Our consolidated results of operations have been adjusted to retrospectively include the historical results of the Lucerne 1 plant for all periods presented.

20. 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 filed with the SEC on June 14, 2012, the parent guarantor has agreed to fully and unconditionally guarantee 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, 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 and an 80% interest in the Eagle Ford system, transfers of net assets between entities under common control that 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 Balance Sheet December 31, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 3	$ 2	$ (3)	$ 2
Accounts receivable, net	—	—	239	—	239
Inventories	—	—	76	—	76
Other	—	—	51	—	51
Total current assets	—	3	368	(3)	368
Property, plant and equipment, net	—	—	2,592	—	2,592
Goodwill and intangible assets, net	—	—	291	—	291
Advances receivable — consolidated subsidiaries	873	1,424	—	(2,297)	—
Investments in consolidated subsidiaries	574	770	—	(1,344)	—
Investments in unconsolidated affiliates	—	—	304	—	304
Other long-term assets	—	11	79	—	90
Total assets	$ 1,447	$ 2,208	$ 3,634	$ (3,644)	$ 3,645
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 12	$ 336	$ (3)	$ 345
Advances payable — consolidated subsidiaries	—	—	2,297	(2,297)	—
Long-term debt	—	1,620	—	—	1,620
Other long-term liabilities	—	2	42	—	44
Total liabilities	—	1,634	2,675	(2,300)	2,009
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Predecessor equity	—	—	399	—	399
Net equity	1,447	584	376	(1,344)	1,063
Accumulated other comprehensive loss	—	(10)	(5)	—	(15)
Total partners' equity	1,447	574	770	(1,344)	1,447
Noncontrolling interests	—	—	189	—	189
Total equity	1,447	574	959	(1,344)	1,636
Total liabilities and equity	$ 1,447	$ 2,208	$ 3,634	$ (3,644)	$ 3,645

(a) The financial information as of December 31, 2012 includes the results of our Lucerne 1 plant and our 80% interest in the Eagle Ford system, transfers of net assets between entities under common control that 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, 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, net	—	(52)	—	—	(52)
Income from consolidated subsidiaries	200	252	—	(452)	—
Earnings from unconsolidated affiliates	—	—	33	—	33
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 our 80% interest in the Eagle Ford system, transfers of net assets between entities under common control that 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 our 80% interest in the Eagle Ford system, transfers of net assets between entities under common control that 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, net	—	(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, 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.

	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 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, 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.

	Condensed Consolidating Statement of Operations Year Ended December 31, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 3,574	$ —	$ 3,574
Transportation, processing and other	—	—	208	—	208
Gains from commodity derivative activity, net	—	—	8	—	8
Total operating revenues	—	—	3,790	—	3,790
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	3,155	—	3,155
Operating and maintenance expense	—	—	192	—	192
Depreciation and amortization expense	—	—	135	—	135
General and administrative expense	—	—	76	—	76
Other income	—	—	(1)	—	(1)
Total operating costs and expenses	—	—	3,557	—	3,557
Operating income	—	—	233	—	233
Interest expense	—	(33)	(1)	—	(34)
Earnings from unconsolidated affiliates	—	—	23	—	23
Income from consolidated subsidiaries	191	224	—	(415)	—
Income before income taxes	191	191	255	(415)	222
Income tax expense	—	—	(1)	—	(1)
Net income	191	191	254	(415)	221
Net income attributable to noncontrolling interests	—	—	(30)	—	(30)
Net income attributable to partners	$ 191	$ 191	$ 224	$ (415)	$ 191

(a) The financial information for the year ended December 31, 2011 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.

Condensed Consolidating Statement of Comprehensive Income
Year Ended December 31, 2011 (a)

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 191	$ 191	$ 254	$ (415)	$ 221
Other comprehensive loss:					
Reclassification of cash flow hedge losses into earnings	—	21	—	—	21
Net unrealized losses on cash flow hedges	—	(12)	(3)	—	(15)
Other comprehensive income from consolidated subsidiaries	6	(3)	—	(3)	—
Total other comprehensive income	6	6	(3) —	(3)	6
Total comprehensive income	197	197	251	(418)	227
Total comprehensive income attributable to noncontrolling interests	—	—	(30)	—	(30)
Total comprehensive income attributable to partners	$ 197	$ 197	$ 221	$ (418)	$ 197

(a) The financial information for the year ended December 31, 2011 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.

	Condensed Consolidating Statement 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)
Acquisition of unconsolidated affiliates	—	—	(86)	—	(86)
Investments in unconsolidated affiliates	—	—	(242)	—	(242)
Net cash (used in) provided by 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
Payments of deferred financing costs	—	(4)	—	—	(4)
Excess purchase price over acquired interests and commodity hedges	—	—	(85)	—	(85)
Proceeds from issuance of common units, net of offering costs	1,083	—	—	—	1,083
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 (used in) 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 for the year ended December 31, 2013 includes the results of our Lucerne 1 plant and our 80% interest in the Eagle Ford system, transfers of net assets between entities under common control that 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) provided by 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 (used in) 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.

	Condensed Consolidating Statements of Cash Flows Year Ended December 31, 2011 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (31)	$ 448	$ —	$ 417
INVESTING ACTIVITIES:					
Intercompany transfers	(38)	(62)	—	100	—
Capital expenditures	—	—	(385)	—	(385)
Acquisitions, net of cash acquired	—	—	(152)	—	(152)
Investments in unconsolidated affiliates	—	—	(8)	—	(8)
Return of investment from unconsolidated affiliate	—	—	2	—	2
Proceeds from sale of assets	—	—	5	—	5
Net cash (used in) provided by investing activities	(38)	(62)	(538)	100	(538)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	100	(100)	—
Proceeds from debt	—	1,524	—	—	1,524
Payments of debt	—	(1,425)	—	—	(1,425)
Payment of deferred financing costs	—	(4)	—	—	(4)
Proceeds from issuance of common units, net of offering costs	170	—	—	—	170
Excess purchase price over acquired unconsolidated affiliates	—	—	(36)	—	(36)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	52	—	52
Distributions to common unitholders and general partner	(132)	—	—	—	(132)
Distributions to noncontrolling interests	—	—	(45)	—	(45)
Contributions from noncontrolling interests	—	—	18	—	18
Net cash provided by (used in) financing activities	38	95	89	(100)	122
Net change in cash and cash equivalents	—	2	(1)	—	1
Cash and cash equivalents, beginning of year	—	2	7	(2)	7
Cash and cash equivalents, end of year	$ —	$ 4	$ 6	$ (2)	$ 8

(a) The financial information as of December 31, 2011, 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 transfers occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

The parent guarantor, subsidiary issuer and non-guarantor subsidiaries participate in a cash pooling program, whereby cash balances are generally swept daily between the parent guarantor and the non-guarantor subsidiaries bank accounts and those of the subsidiary issuer.

Subsequent to the issuance of the 2013 financial statements, management determined that intercompany transfers between the parent guarantor and the non-guarantor subsidiaries, as well as the subsidiary issuer and the non-guarantor subsidiaries, should be classified as investing activities by the parent guarantor and subsidiary issuer and financing activities by the non-guarantor subsidiaries, within the condensed consolidating statements of cash flows. The intercompany transfers had previously been reported as operating activities by the parent guarantor, subsidiary issuer and non-guarantor subsidiaries. The classification of these intercompany transfers has been corrected in the condensed consolidating financial statements for the years ended December 31, 2013, 2012 and 2011. This correction has no impact on the consolidated statement of cash flows for all years presented. These amounts have been included within the line item “intercompany transfers” in investing and financing activities within the condensed consolidating statements of cash flows. The changes to the previously reported amounts are summarized as follows:

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Year Ended December 31, 2013					
Net cash (used in) provided by operating activities	$ 806	$ 258	$ (1,064)	$ —	$ —
Net cash (used in) provided by investing activities	$ (806)	$ (258)	$ —	$ 1,064	$ —
Net cash provided by (used in) financing activities	$ —	$ —	$ 1,064	$ (1,064)	$ —
Year Ended December 31, 2012					
Net cash (used in) provided by operating activities	$ 274	$ 827	$ (1,101)	$ —	$ —
Net cash (used in) provided by investing activities	$ (274)	$ (827)	$ —	$ 1,101	$ —
Net cash provided by (used in) financing activities	$ —	$ —	$ 1,101	$ (1,101)	$ —
Year Ended December 31, 2011					
Net cash (used in) provided by operating activities	$ 38	$ 62	$ (100)	$ —	$ —
Net cash (used in) provided by investing activities	$ (38)	$ (62)	$ —	$ 100	$ —
Net cash provided by (used in) financing activities	$ —	$ —	$ 100	$ (100)	$ —

21. Valuation and Qualifying Accounts and Reserves

Our valuation and qualifying accounts and reserves for the years ended December 31, 2013, 2012, and 2011 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, 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
December 31, 2011					
Environmental	$ 3	$ —	$ —	$ —	$ 3
Litigation	1	—	—	(1)	—
Other (a)	—	1	—	—	1
	$ 4	$ 1	$ —	$ (1)	$ 4

(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.

22. Subsequent Events

On January 28, 2014, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.7325 per unit, payable on February 14, 2014 to unitholders of record on February 7, 2014.

On February 25, 2014, we entered into various transaction documents with DCP Midstream, LLC and its affiliates for the contribution or acquisition of (i) the remaining 20% interest in DCP SC Texas GP; (ii) a 33.33% membership interest in each DCP Southern Hills Pipeline, LLC, which owns the Southern Hills pipeline, and DCP Sand Hills Pipeline, LLC, which owns the Sand Hills pipeline; (iii) the Lucerne 1 plant; and (iv) the Lucerne 2 plant. Total consideration for these transactions at closing was $1,220 million, subject to certain working capital and other customary adjustments. These transactions closed in March 2014. The Southern Hills pipeline is engaged in the business of transporting NGLs, and consists of approximately 800 miles of pipeline, with an expected capacity of 175 MBbls/d after completion of planned pump stations. The pipeline provides NGL takeaway service from the Midcontinent to fractionation facilities along the Texas Gulf Coast and 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. The Sand Hills pipeline is also engaged in the business of transporting NGLs and consists of approximately 720 miles of pipeline, with an expected initial capacity of 200 MBbls/d after completion of pump stations, and possible further capacity increases with the installation of additional pump stations. The pipeline provides NGL takeaway service from the Permian and Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and 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.

Exhibit 99.4

Supplementary Information — Condensed Consolidating Statements of Cash Flows

Subsequent to the issuance of the March 31, 2014 financial statements, management determined that intercompany transfers between the parent guarantor and the non-guarantor subsidiaries, as well as the subsidiary issuer and the non-guarantor subsidiaries, should be classified as investing activities by the parent guarantor and subsidiary issuer and financing activities by the non-guarantor subsidiaries, within the condensed consolidating statements of cash flows. The intercompany transfers had previously been reported as operating activities by the parent guarantor, subsidiary issuer and non-guarantor subsidiaries. The classification of these intercompany transfers has been corrected in the condensed consolidating financial statements for the periods ended March 31, 2014, and 2013. This correction has no impact on the condensed consolidated statement of cash flows for all periods presented. These amounts have been included within the line item "intercompany transfers" in investing and financing activities within the condensed consolidating statements of cash flows.

Condensed Consolidating Statement of Cash Flows
Three Months Ended March 31, 2014 (a)

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	—	(11)	157	—	146
INVESTING ACTIVITIES:					
Intercompany transfers	(591)	(365)	—	956	—
Capital expenditures	—	—	(63)	—	(63)
Acquisitions, net of cash acquired	—	—	(100)	—	(100)
Acquisition of unconsolidated affiliates	—	—	(669)	—	(669)
Investments in unconsolidated affiliates	—	—	(65)	—	(65)
Other	—	—	1	—	1
Net cash (used in) provided by investing activities	(591)	(365)	(896)	956	(896)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	956	(956)	—
Proceeds from long-term debt	—	719	—	—	719
Payments of commercial paper, net	—	(314)	—	—	(314)
Payments of deferred financing costs	—	(6)	—	—	(6)
Excess purchase price over acquired interests and commodity hedges	—	—	(14)	—	(14)
Proceeds from issuance of common units, net of offering costs	677	—	—	—	677
Net change in advances to predecessor from DCP Midstream, LLC	—	—	(6)	—	(6)
Distributions to limited partners and general partner	(86)	—	—	—	(86)
Distributions to noncontrolling interests	—	—	(10)	—	(10)
Purchase of additional interest in a subsidiary	—	—	(198)	—	(198)
Contributions from noncontrolling interests	—	—	3	—	3
Net cash provided by (used in) financing activities	591	399	731	(956)	765
Net change in cash and cash equivalents	—	23	(8)	—	15
Cash and cash equivalents, beginning of period	—	—	12	—	12
Cash and cash equivalents, end of period	—	23	4	—	27

(a) The financial information for the three months ended March 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
Three Months Ended March 31, 2013 (a)

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (1)	$ 159	$ (6)	$ 152
INVESTING ACTIVITIES:					
Intercompany transfers	(440)	(72)	—	512	—
Capital expenditures	—	—	(101)	—	(101)
Acquisitions, net of cash acquired	—	—	(481)	—	(481)
Investments in unconsolidated affiliates	—	—	(26)	—	(26)
Net cash (used in) provided by investing activities	(440)	(72)	(608)	512	(608)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	512	(512)	—
Proceeds from long-term debt	—	809	—	—	809
Payments of long-term debt	—	(690)	—	—	(690)
Payment of deferred financing costs	—	(4)	—	—	(4)
Proceeds from issuance of common units, net of offering costs	494	—	—	—	494
Excess purchase price over acquired assets	—	—	(94)	—	(94)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	22	—	22
Distributions to common unitholders and general partner	(54)	—	—	—	(54)
Distributions to noncontrolling interests	—	—	(5)	—	(5)
Contributions from noncontrolling interests	—	—	15	—	15
Distributions to DCP Midstream, LLC	—	—	(3)	—	(3)
Contributions from DCP Midstream, LLC	—	—	1	—	1
Net cash provided by (used in) financing activities	440	115	448	(512)	491
Net change in cash and cash equivalents	—	42	(1)	(6)	35
Cash and cash equivalents, beginning of period	—	3	2	(3)	2
Cash and cash equivalents, end of period	$ —	$ 45	$ 1	$ (9)	$ 37

(a) The financial information during the three months ended March 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.

The parent guarantor, subsidiary issuer and non-guarantor subsidiaries participate in a cash pooling program, whereby cash balances are generally swept daily between the parent guarantor and the non-guarantor subsidiaries bank accounts and those of the subsidiary issuer.

The changes to the previously reported amounts are summarized as follows:

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Three Months Ended March 31, 2014					
Net cash (used in) provided by operating activities	$ 591	$ 365	$ (956)	$ —	$ —
Net cash (used in) provided by investing activities	$ (591)	$ (365)	$ —	$ 956	$ —
Net cash provided by (used in) financing activities	$ —	$ —	$ 956	$ (956)	$ —
Three Months Ended March 31, 2013					
Net cash (used in) provided by operating activities	$ 440	$ 72	$ (512)	$ —	$ —
Net cash (used in) provided by investing activities	$ (440)	$ (72)	$ —	$ 512	$ —
Net cash provided by (used in) financing activities	$ —	$ —	$ 512	$ (512)	$ —