DCP Midstream, LLC
Consolidated Financial Statements for the Years Ended December 31, 2014, 2013 and 2012

DCP MIDSTREAM, LLC
CONSOLIDATED FINANCIAL STATEMENTS

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Members of
DCP Midstream, LLC
Denver, Colorado

We have audited the accompanying consolidated financial statements of DCP Midstream, LLC and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2014, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of DCP Midstream, LLC and its subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in accordance with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

February 26, 2015

DCP MIDSTREAM, LLC
CONSOLIDATED BALANCE SHEETS
(millions)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 27	$ 31
Accounts receivable:		
Customers, net of allowance for doubtful accounts of $3 million and $4 million, respectively	813	1,139
Affiliates	180	265
Other	39	28
Inventories	76	96
Unrealized gains on derivative instruments	165	59
Other	80	45
Total current assets	1,380	1,663
Property, plant and equipment, net	9,537	8,420
Investments in unconsolidated affiliates	1,463	1,378
Intangible assets, net	290	311
Goodwill	704	722
Unrealized gains on derivative instruments	23	10
Other long-term assets	282	217
Total assets	$ 13,679	$ 12,721
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 904	$ 1,296
Affiliates	35	59
Other	58	58
Short-term borrowings	1,012	1,300
Current maturities of long-term debt	450	—
Unrealized losses on derivative instruments	124	64
Accrued taxes	34	37
Other	321	300
Total current liabilities	2,938	3,114
Deferred income taxes	105	96
Long-term debt	5,233	4,962
Unrealized losses on derivative instruments	15	2
Other long-term liabilities	185	158
Total liabilities	8,476	8,332
Commitments and contingent liabilities		
Equity:		
Members’ interest	2,630	2,670
Accumulated other comprehensive loss	(5)	(6)
Total members’ equity	2,625	2,664
Noncontrolling interest	2,578	1,725
Total equity	5,203	4,389
Total liabilities and equity	$ 13,679	$ 12,721

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
(millions)

	Year Ended December 31,		
	2014	2013	2012
Operating revenues:			
Sales of natural gas and NGL products	$ 11,378	$ 9,807	$ 7,826
Sales of natural gas and NGL products to affiliates	2,030	1,732	1,886
Transportation, storage and processing	517	463	373
Trading and marketing gains, net	88	36	86
Total operating revenues	14,013	12,038	10,171
Operating costs and expenses:			
Purchases of natural gas and NGL products	11,361	9,679	7,662
Purchases of natural gas and NGL products from affiliates	467	288	510
Operating and maintenance	780	691	667
Depreciation and amortization	348	314	291
General and administrative	281	280	297
Loss (gain) on sale of assets and goodwill impairment	25	(22)	—
Total operating costs and expenses	13,262	11,230	9,427
Operating income	751	808	744
Earnings from unconsolidated affiliates	83	35	34
Interest expense, net	(287)	(249)	(193)
Income before income taxes	547	594	585
Income tax expense	(11)	(10)	(2)
Net income	536	584	583
Net income attributable to noncontrolling interests	(248)	(93)	(97)
Net income attributable to members' interests	$ 288	$ 491	$ 486

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(millions)

	Year Ended December 31,		
	2014	**2013**	**2012**
Net income	$ 536	$ 584	$ 583
Other comprehensive income:			
Net unrealized gains on cash flow hedges	—	—	1
Reclassification of cash flow hedge losses into earnings	2	3	11
Total other comprehensive income	2	3	12
Total comprehensive income	538	587	595
Total comprehensive income attributable to noncontrolling interests	(249)	(93)	(106)
Total comprehensive income attributable to members' interests	$ 289	494	489

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
(millions)

	Year Ended December 31,		
	2014	**2013**	**2012**
Cash flows from operating activities:			
Net income	$ 536	$ 584	$ 583
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	348	314	291
Earnings from unconsolidated affiliates	(83)	(35)	(34)
Distributions from unconsolidated affiliates	141	52	36
Deferred income tax expense (benefit)	9	4	(1)
Net unrealized gains on derivative instruments	(43)	(5)	—
Loss (gain) on sale of assets and goodwill impairment	25	(22)	—
Other, net	27	20	6
Changes in operating assets and liabilities which provided (used) cash:			
Accounts receivable	397	(333)	241
Inventories	16	9	(9)
Accounts payable	(452)	300	(630)
Other	(104)	(50)	(139)
Net cash provided by operating activities	817	838	344
Cash flows from investing activities:			
Capital expenditures	(1,384)	(1,420)	(2,285)
Acquisitions, net of cash acquired	—	—	(123)
Proceeds from sales of two-thirds interest in Sand Hills and Southern Hills	—	—	919
Investments in unconsolidated affiliates	(161)	(523)	(240)
Proceeds from sale of assets and equity method investments	30	46	1
Net cash used in investing activities	(1,515)	(1,897)	(1,728)
Cash flows from financing activities:			
Payment of dividends and distributions to members	(474)	(430)	(405)
Proceeds from long-term debt	719	2,507	2,915
Payment of long-term debt	—	(2,238)	(2,042)
Proceeds from issuance of common units by DCP Partners, net of offering costs	1,001	1,083	455
(Repayment) borrowings of commercial paper, net	(288)	342	588
Distributions paid to noncontrolling interests	(252)	(167)	(112)
Payment of deferred financing costs	(12)	(11)	(20)
Net cash provided by financing activities	694	1,086	1,379
Net change in cash and cash equivalents	(4)	27	(5)
Cash and cash equivalents, beginning of period	31	4	9
Cash and cash equivalents, end of period	$ 27	$ 31	$ 4

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(millions)

	Members' Equity			
	Members' Interest	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interest	Total Equity
Balance, January 1, 2012	$ 2,164	$ (12)	$ 537	$ 2,689
Net income	486	—	97	583
Other comprehensive income	—	3	9	12
Dividends and distributions	(310)	—	(112)	(422)
Issuance of common units by DCP Partners, net of offering costs	73	—	382	455
Balance, December 31, 2012	2,413	(9)	913	3,317
Net income	491	—	93	584
Other comprehensive income	—	3	—	3
Dividends and distributions	(430)	—	(167)	(597)
Issuance of common units by DCP Partners, net of offering costs	196	—	886	1,082
Balance, December 31, 2013	2,670	(6)	1,725	4,389
Net income	288	—	248	536
Other comprehensive income	—	1	1	2
Dividends and distributions	(474)	—	(252)	(726)
Issuance of common units by DCP Partners, net of offering costs	146	—	856	1,002
Balance, December 31, 2014	$ 2,630	$ (5)	$ 2,578	$ 5,203

See Notes to Consolidated Financial Statements.

1. Description of Business and Basis of Presentation

DCP Midstream, LLC, with its consolidated subsidiaries, or us, we, our, or the Company, is a joint venture owned 50% by Phillips 66 and its affiliates, or Phillips 66, and 50% by Spectra Energy Corp and its affiliates, or Spectra Energy. We operate in the midstream natural gas industry and are engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas and producing, fractionating, transporting, storing and selling natural gas liquids, or NGLs, and recovering and selling condensate. Additionally, we generate revenues by trading and marketing natural gas and NGLs.

DCP Midstream Partners, LP, or DCP Partners, is a master limited partnership, of which we act as general partner. As of December 31, 2014 and 2013, we owned an approximate 22% and 23% interest in DCP Partners, respectively, including our limited partner and general partner interests. We also own incentive distribution rights that entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved. As the general partner of DCP Partners, we have responsibility for its operations.

We are governed by a five member board of directors, consisting of two voting members from each of Phillips 66 and Spectra Energy and our Chairman of the Board, President and Chief Executive Officer, a non-voting member. All decisions requiring the approval of our board of directors are made by simple majority vote of the board, but must include at least one vote from both a Phillips 66 and Spectra Energy board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Phillips 66 and Spectra Energy.

The consolidated financial statements include the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control and undivided interests in jointly owned assets. We also consolidate DCP Partners, which we control through our ownership and general partner interest, and where the limited partners do not have substantive kick-out or participating rights. 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. Intercompany balances and transactions have been eliminated.

2. Summary of Significant Accounting Policies

Use of Estimates — Conformity with accounting principles generally accepted in the United States of America, or 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 — Cash and cash equivalents include all cash balances and 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.

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

Inventories — Inventories, which consist primarily of natural gas and NGLs held in storage for transportation, processing and sales commitments, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Accounting for Risk Management and Derivative Activities and Financial Instruments — We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales contract. The remaining other non-trading derivatives, which are related to asset based activities for which hedge accounting or 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 on 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
Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses
Non-Trading Derivatives:		
Cash Flow Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method (c)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale
Other Non-Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses

(a) 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 trading and marketing gains and losses during the current period.
(b) Hedge method — An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery impacts earnings. For fair value hedges, the changes 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.
(c) Accrual method — An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery impacts earnings.

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 the consolidated balance sheets as 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 in the consolidated balance sheets 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. The change in fair value of all derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the consolidated 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 internally developed pricing models developed primarily from historical relationships with quoted market prices and the expected relationship with quoted market prices.

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

Property, Plant and Equipment — Property, plant and equipment are recorded at historical cost. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Capitalized Interest — We capitalize interest during construction of major projects. Interest is calculated on the monthly outstanding capital balance and ceases in the month that the asset is placed into service. We also capitalize interest on our equity method investments which are devoting substantially all efforts to establishing a new business and have not yet begun planned principal operations. Capitalization ceases when the investee commences planned principal operations. The rates used to calculate capitalized interest are the weighted-average cost of debt, including the impact of interest rate swaps.

Asset Retirement Obligations — 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.

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.

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 in 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. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill and intangible assets impairment charges for other reporting units due to the potential impact on our operations and cash flows.

Intangible assets consist primarily of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit. Intangible assets are removed from the gross carrying amount and the total of accumulated amortization in the period in which they become fully amortized.

Investments in Unconsolidated Affiliates — We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When there is evidence of loss in value that is other than temporary, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Long-Lived Assets — We 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:

- a 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 determine the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management's intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

Unamortized Debt Premium, Discount and Expense — Premiums, discounts and expenses incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. The premiums and discounts are recorded on the consolidated balance sheets within the carrying amount of long-term debt. The unamortized expenses are recorded on the consolidated balance sheets as other long-term assets.

Noncontrolling Interest **—** Noncontrolling interest represents the ownership interests of third-party entities in the net assets of consolidated affiliates, including the ownership interest of DCP Partners' public unitholders, through DCP Partners' publicly traded common units, in net assets of DCP Partners and the noncontrolling interest which is recorded in DCP Partners' consolidated balance sheets. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party 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 investors.

Dividends and Distributions — Under the terms of the Second Amended and Restated LLC Agreement dated July 5, 2005, as amended, or the LLC Agreement, we are required to make quarterly distributions to Phillips 66 and Spectra Energy based on allocated taxable income. The LLC Agreement provides for taxable income to be allocated in accordance with Internal Revenue Code Section 704(c). This Code Section accounts for the variation between the adjusted tax basis and the fair market value of assets contributed to the joint venture. The distribution is based on the highest taxable income allocated to either member, with the other member receiving a proportionate amount to maintain the ownership capital accounts at 50% for both Phillips 66 and Spectra Energy. Tax distributions to the members are calculated based on estimated annual taxable income allocated to the members according to their respective ownership percentages at the date the distributions became due. Our board of directors determines the amount of the periodic dividends to be paid by considering net income attributable to members' interests, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. Dividends are allocated to the members in accordance with their respective ownership percentages.

DCP Partners considers the payment of a quarterly distribution to the holders of its common units, to the extent DCP Partners has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a 100% owned subsidiary of ours. There is no guarantee, however, that DCP Partners will pay the minimum quarterly distribution on the units in any quarter. DCP Partners will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement.

Revenue Recognition — We generate the majority of our revenues from gathering, processing, compressing, treating, transporting, storing and selling natural gas and producing, fractionating, transporting, storing and selling NGLs and recovering and selling condensate, as well as trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas, NGLs and condensate, or by receiving fees.

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:

- *Percent-of-proceeds/index arrangements* — Under percent-of-proceeds/index 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 published index 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 or contractual recoveries 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-liquid arrangements, we do not keep any amounts related to the 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/index arrangements relate directly with the price of natural gas, NGLs and condensate. Our revenues under percent-of-liquids arrangements relate directly to the price of NGLs and condensate.

- *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.

- *Keep-whole and wellhead purchase 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 British thermal unit, or 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 the terms of a wellhead purchase contract, we purchase natural gas from the producer at the wellhead or defined receipt point for processing and then market the resulting NGLs and residue gas at market prices. Under these types of contracts, we are exposed to the difference between the value of the NGLs extracted from processing and the value of the Btu equivalent of residue natural gas, or frac spread. We benefit in periods when NGL prices are higher relative to natural gas prices when that frac spread exceeds our operating costs.

Our trading and marketing of natural gas and NGL products consists of physical purchases and sales, as well as 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 of the product, and incur the risks and rewards of ownership. New or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues for our NGL and residue gas derivative trading activities net in the consolidated statements of operations as trading and marketing gains and losses. These activities include mark-to-market gains and losses on energy trading contracts, and the settlement of financial and physical energy trading contracts.

Revenue for goods and services provided but not invoiced is estimated each month and recorded along with related purchases of goods and services used but not invoiced. These estimates are generally based on estimated commodity prices, preliminary throughput measurements and allocations and contract data. There are no material differences between the actual amounts and the estimated amounts of revenues and purchases recorded at December 31, 2014, 2013 and 2012.

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. Included in the consolidated balance sheets as accounts receivable — other, as of December 31, 2014 and 2013, were imbalances totaling $38 million and $28 million, respectively. Included in the consolidated balance sheets as accounts payable — other, as of both December 31, 2014 and 2013, were imbalances totaling $58 million.

Significant Customers — There were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2014, 2013 or 2012. We had significant transactions with affiliates. See Note 5, Agreements and Transactions with Related Parties and 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.

Equity-Based Compensation — Liability classified share-based compensation cost is remeasured at each reporting date at fair value, based on the closing security 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.

Accounting for Sales of Units by a Subsidiary — We account for sales of units by a subsidiary by recording an increase or decrease in members' interest within equity equal to the amount of net proceeds received in excess or deficit of the carrying value of the units sold. The remaining net proceeds are recorded as an increase to noncontrolling interest.

Income Taxes — We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state, local, franchise and margin taxes of the limited liability company and other 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 included in the federal returns of each partner.

3. Recent Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2014-09 "Revenue from Contracts with Customers (Topic 606)," **or ASU 2014-09** — In May 2014, the FASB issued ASU 2014-09, which supersedes the revenue recognition requirements of Accounting Standards Codification, or ASC, Topic 605 "Revenue Recognition." We intend to adopt this ASU when it is effective for public entities, which is for annual reporting periods beginning after December 15, 2016 and we are currently assessing the impact of adoption on our consolidated results of operations, cash flows and financial position.

ASU 2014-12 "Compensation — Stock Compensation (Topic 718): Accounting for Share-Based payments When the Terms of an Award Provide That a Performance Target Could be Achieved after the Requisite Service Period," **or ASU 2014-12** — In May 2014, the FASB issued ASU 2014-12, which provides more explicit guidance for treating share-based payment awards that require a specific performance target that affects vesting and that could be achieved after the requisite service period as a performance condition. This ASU is effective for interim and annual reporting periods beginning after December 15, 2015 and is not expected to have a material impact on our consolidated results of operations, cash flows and financial position.

4. Dispositions

In August 2014, we entered into a purchase and sale agreement with American Midstream, LLC to divest our two-thirds ownership interest in Main Pass Oil Gathering Company, or Main Pass, for total proceeds of approximately $14 million and selling costs of approximately $3 million. This transaction closed on August 11, 2014, and we recognized a $6 million loss on sale in the consolidated statements of operations for the year ended December 31, 2014.

5. Agreements and Transactions with Related Parties and Affiliates

Dividends and Distributions

During the years ended December 31, 2014, 2013 and 2012, we paid tax distributions to the members of $159 million, $18 million and $244 million, respectively, based on estimated annual taxable income allocated to Phillips 66 and Spectra Energy according to their respective ownership percentages at the date the distributions became due. During the years ended December 31, 2014, 2013 and 2012, we declared and paid dividends of $315 million, $412 million and $161 million, respectively, to Phillips 66 and Spectra Energy, allocated in accordance with their respective ownership percentages. During the years ended December 31, 2014, 2013 and 2012, DCP Partners paid distributions of $247 million, $161 million and $106 million, respectively, to its public unitholders.

Phillips 66, CPChem and ConocoPhillips

Long-Term NGL Purchases Contract and Transactions — We sell a portion of our NGLs to Phillips 66 and Chevron Phillips Chemical LLC, or CPChem. In addition, we purchase NGLs from CPChem. CPChem is owned 50% by Phillips 66, and is considered a related party. Prior to December 31, 2014, approximately 35% of our NGL production was committed to Phillips 66 and CPChem, under 15-year contracts, the primary production commitment of which began a wind down period in December 2014 and expires in January 2019. We anticipate continuing to purchase and sell commodities with Phillips 66 and CPChem in the ordinary course of business.

Spectra Energy

Commodity Transactions — We sell a portion of our residue gas and NGLs to, purchase natural gas and other NGL products from, and provide gathering, transportation and other services to Spectra Energy. Management anticipates continuing to purchase and sell commodities and provide services to Spectra Energy in the ordinary course of business.

DCP Partners

We have entered into a services agreement, as amended, or the Services Agreement, with DCP Partners. Under the Services Agreement, DCP Partners is required to reimburse us for salaries of operating personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by us on behalf of DCP Partners. DCP Partners also pays us an annual fee under the Services Agreement for centralized corporate functions performed by us on behalf of DCP Partners. Except with respect to the annual fee, there is no limit on the reimbursements DCP Partners makes to us under the Services Agreement for other expenses and expenditures incurred or payments made by us on behalf of DCP Partners. Reimbursements received from DCP Partners have been eliminated in consolidation. In the event DCP Partners acquires assets or its business otherwise expands, the annual fee under the Services Agreement is subject to adjustment based on the nature and extent of general and administrative services performed by us on DCP Partners' behalf, as well as an annual adjustment based on the changes to the Consumer Price Index.

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

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

In March 2014, we contributed: (i) our 33.33% membership interest in DCP Sand Hills Pipeline, LLC, or Sand Hills, which owns the Sand Hills pipeline, and our 33.33% interest in DCP Southern Hills Pipeline, LLC, or Southern Hills, which owns the Southern Hills pipeline; (ii) the remaining 20% interest in the Eagle Ford system; (iii) a 35 million cubic feet per day, or 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 in Weld County, Colorado, which is currently under construction, or the Lucerne 2 plant, to DCP Partners, collectively referred to as the March 2014 Transactions. Total consideration for the March 2014 Transactions at closing was $1,220 million, less customary working capital and other adjustments. We will continue to account for Sand Hills and Southern Hills as equity method investments through our consolidation of DCP Partners.

Unconsolidated Affiliates

We, along with other third party shippers, have entered into 15-year transportation agreements with Sand Hills, Southern Hills, Front Range Pipeline LLC, or Front Range, and Texas Express Pipeline LLC, or Texas Express. Under the terms of these 15-year agreements, which commenced at each of the pipelines' respective in-service dates, we have committed to transport minimum throughput volumes at rates defined in each of the pipelines' respective tariffs.

Under the terms of the Sand Hills LLC Agreement and the Southern Hills LLC Agreement, or the Sand Hills and Southern Hills LLC Agreements, Sand Hills and Southern Hills are required to reimburse us for any direct costs or expenses (other than general and administration services) which we incur on behalf of Sand Hills and Southern Hills. Additionally, Sand Hills and Southern Hills pay us an annual service fee totaling $10 million, for centralized corporate functions provided by us as operator of Sand Hills and Southern Hills, 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 service fee, there is no limit on the reimbursements Sand Hills and Southern Hills make to us under the Sand Hills and Southern Hills LLC Agreements for other expenses and expenditures which we incur on behalf of Sand Hills or Southern Hills.

Competition

Our related parties or affiliates, including DCP Partners, Phillips 66 and Spectra Energy, are not restricted, under either the LLC Agreement or the Services Agreement, from competing with us. Our related parties or affiliates, including DCP Partners, 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.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase natural gas and other NGL products from, and provide gathering and transportation services to unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

The following table summarizes our transactions with related parties and affiliates:

	Year Ended December 31,		
	2014	2013	2012
		(millions)	
Phillips 66 (including CPChem) (a):			
Sales of natural gas and NGL products to affiliates	$ 1,960	$ 1,665	$ 1,028
Transportation, storage and processing	$ —	$ 1	$ —
Purchases of natural gas and NGL products from affiliates	$ 11	$ 14	$ 21
Operating and general and administrative expenses (b)	$ 3	$ (11)	$ 3
ConocoPhillips (a):			
Sales of natural gas and NGL products to affiliates	$ —	$ —	$ 800
Transportation, storage and processing	$ —	$ —	$ 5
Purchases of natural gas and NGL products from affiliates	$ —	$ —	$ 192
Operating and general and administrative expenses (c)	$ —	$ —	$ (1)
Spectra Energy:			
Transportation, storage and processing	$ 14	$ —	$ —
Purchases of natural gas and NGL products from affiliates	$ 88	$ 74	$ 181
Operating and general and administrative expenses	$ 10	$ 10	$ 12
Unconsolidated affiliates:			
Sales of natural gas and NGL products to affiliates	$ 70	$ 67	$ 58
Transportation, storage and processing	$ 12	$ 10	$ 16
Purchases of natural gas and NGL products from affiliates	$ 368	$ 200	$ 116

(a) On May 1, 2012, ConocoPhillips created two independent publicly traded companies by separating its downstream businesses, including its 50% ownership in us, to a newly formed company, Phillips 66. As a result of this transaction, ConocoPhillips is not considered a related party for periods after May 1, 2012.

(b) The year ended December 31, 2013 includes a gain on the sale of sections of our existing Seaway pipeline to Phillips 66, which was treated as a reduction to operating expense in the consolidated statements of operations.

(c) The year ended December 31, 2012 includes hurricane insurance recovery receivables, which were treated as a reduction to operating expense in the consolidated statements of operations.

We had balances with related parties and affiliates as follows:

	December 31, 2014		December 31, 2013	
	(millions)			
Phillips 66 (including CPChem):				
Accounts receivable	$	161	$	236
Accounts payable	$	(4)	$	(17)
Other assets	$	1	$	2
Spectra Energy:				
Accounts receivable	$	1	$	1
Accounts payable	$	(4)	$	(6)
Other assets	$	1	$	1
Unconsolidated affiliates:				
Accounts receivable	$	18	$	28
Accounts payable	$	(27)	$	(36)
Other assets	$	30	$	18

6. Inventories

Inventories were as follows:

	December 31, 2014		December 31, 2013	
	(millions)			
Natural gas	$	36	$	39
NGLs		40		57
Total inventories	$	76	$	96

We recognize lower of cost or market adjustments when the carrying value of our inventories exceeds their estimated market value. These non-cash charges are a component of purchases of natural gas, propane and NGLs in the consolidated statements of operations. We recognized $24 million, $4 million and $19 million in lower of cost or market adjustments during the years ended December 31, 2014, 2013 and 2012, respectively.

7. Property, Plant and Equipment

Property, plant and equipment by classification were as follows:

	Depreciable Life	December 31, 2014		December 31, 2013	
		(millions)			
Gathering and transmission systems	20 - 50 years	$	8,434	$	7,986
Processing, storage and terminal facilities	35 - 60 years		4,522		3,908
Other	3 - 30 years		415		366
Construction work in progress			1,159		831
Property, plant and equipment			14,530		13,091
Accumulated depreciation			(4,993)		(4,671)
Property, plant and equipment, net		$	9,537	$	8,420

Interest capitalized on construction projects for the years ended December 31, 2014, 2013 and 2012 was $34 million, $40 million and $79 million, respectively.

Depreciation expense for the years ended December 31, 2014, 2013 and 2012 was $327 million, $289 million and $265 million, respectively.

Asset Retirement Obligations — As of December 31, 2014 and 2013, we had $117 million and $93 million, respectively, of asset retirement obligations, or AROs, in other long-term liabilities in the consolidated balance sheets. Accretion expense is recorded within operating and maintenance expense in our consolidated statements of operations.

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 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 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.

The following table summarizes changes in the asset retirement obligations included in our balance sheets:

	December 31,	
	2014	2013
	(millions)	
Balance, beginning of period	$ 93	$ 91
Accretion expense (benefit)	6	(1)
Revisions in estimated cash flows	18	3
Balance, end of period	$ 117	$ 93

8. Goodwill and Intangible Assets

The change in the carrying amount of goodwill is as follows:

	December 31,	
	2014	2013
	(millions)	
Balance, beginning of period	$ 722	$ 723
Impairment	(18)	—
Dispositions	—	(1)
Balance, end of period	$ 704	$ 722

We performed our annual goodwill assessment at the reporting unit level. We primarily used a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill impairment charges for other reporting units due to the potential impact on our operations and cash flows.

The disposition of Main Pass was considered a triggering event for a goodwill impairment analysis for the related reporting unit. We determined that the estimated fair value of the related reporting unit was less than its carrying amount, primarily due to current economic factors and changes in assumptions related to potential future revenues of this reporting unit. An assessment of these factors in step one of the goodwill impairment test led to a conclusion that the estimated fair value of the reporting unit was less than its carrying amount. The fair value was assessed utilizing a probability weighted approach which included discounted cash flow and market-based valuation techniques. We then applied the second step of the goodwill impairment test, allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. As a result of this analysis, we recorded a full impairment of the goodwill associated with this reporting unit totaling $18 million during the third quarter of 2014, which is included in loss on sale of assets and goodwill impairment in the consolidated statements of operations. We concluded that the fair value of goodwill of our remaining reporting units exceeded its carrying value, and the entire amount of goodwill disclosed on the consolidated balance sheet associated with these remaining reporting units is recoverable, therefore, no other goodwill impairments were identified or recorded for the remaining reporting units as a result of our annual goodwill assessment.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and are as follows:

	December 31, 2014	December 31, 2013
	(millions)	
Gross carrying amount	$ 524	$ 524
Accumulated amortization	(234)	(213)
Intangible assets, net	$ 290	$ 311

For the years ended December 31, 2014, 2013 and 2012, we recorded amortization expense of $21 million, $25 million and $26 million, respectively. As of December 31, 2014, the remaining amortization periods ranged from approximately 4 years to approximately 21 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)	
2015	$ 19
2016	19
2017	19
2018	18
2019	18
Thereafter	197
Total	$ 290

9. Investments in Unconsolidated Affiliates

We had investments in the following unconsolidated affiliates accounted for using the equity method:

	Percentage Ownership	December 31, 2014	December 31, 2013
		(millions)	
DCP Sand Hills Pipeline, LLC	33.33%	$ 413	$ 402
Discovery Producer Services, LLC	40.00%	407	347
DCP Southern Hills Pipeline, LLC	33.33%	329	325
Front Range Pipeline LLC	33.33%	169	134
Texas Express Pipeline LLC	10.00%	98	96
Mont Belvieu Enterprise Fractionator	12.50%	23	25
Main Pass Oil Gathering Company (a)	66.67%	—	23
Mont Belvieu I Fractionation Facility	20.00%	14	16
Other unconsolidated affiliates	Various	10	10
Total investments in unconsolidated affiliates		$ 1,463	$ 1,378

(a) In August 2014, we sold our two-thirds ownership interest in Main Pass. See Note 4, Dispositions.

There was an excess of the carrying amount of the investment over the underlying equity of Sand Hills of $10 million at both December 31, 2014 and 2013, which is associated with interest capitalized during the construction of the Sand Hills pipeline. The Sand Hills pipeline was placed into service in the second quarter of 2013, and the excess carrying amount is being amortized over the life of the underlying long-lived assets of Sand Hills.

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery Producer Services, LLC, or Discovery, of $25 million and $28 million as of December 31, 2014 and 2013, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Discovery.

There was an excess of the carrying amount of the investment over the underlying equity of Southern Hills of $7 million and $8 million as of December 31, 2014 and 2013, respectively, which is associated with interest capitalized during the construction of the Southern Hills pipeline. The Southern Hills pipeline was placed into service in the second quarter of 2013, and the excess carrying amount is being amortized over the life of the underlying long-lived assets of Southern Hills.

There was an excess of the carrying amount of the investment over the underlying equity of Front Range of $5 million and $4 million as of December 31, 2014 and 2013, respectively, which is associated with interest capitalized during the construction of the Front Range pipeline. The Front Range pipeline was placed into service in the first quarter of 2014, and the excess carrying amount is being amortized over the life of the underlying long-lived assets of Front Range.

There was an excess of the carrying amount of the investment over the underlying equity of Texas Express of $3 million at both December 31, 2014 and 2013, which is associated with interest capitalized during the construction of the Texas Express pipeline. The Texas Express pipeline was placed into service in the fourth quarter of 2013, and the excess carrying amount is being amortized over the life of the underlying long-lived assets of Texas Express.

There was an excess of the carrying amount of the investment over the underlying equity of Main Pass of approximately $7 million as of December 31, 2013. In August 2014, we sold our two-thirds ownership interest in Main Pass. See Note 4, Dispositions.

There was a deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu I Fractionation Facility, or Mont Belvieu I, of $4 million and $5 million as of December 31, 2014 and 2013, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Mont Belvieu I.

Earnings (loss) from unconsolidated affiliates amounted to the following:

	Year Ended December 31,		
	2014	2013	2012
		(millions)	
DCP Sand Hills Pipeline, LLC	$ 27	$ 5	$ —
Discovery Producer Services, LLC	7	1	13
DCP Southern Hills Pipeline, LLC	15	(2)	—
Front Range Pipeline LLC	2	—	—
Texas Express Pipeline LLC	3	(1)	—
Mont Belvieu Enterprise Fractionator	17	13	12
Main Pass Oil Gathering Company (a)	—	1	—
Mont Belvieu I Fractionation Facility	12	19	9
Other unconsolidated affiliates	—	(1)	—
Total earnings from unconsolidated affiliates	$ 83	$ 35	$ 34

(a) In August 2014, we sold our two-thirds ownership interest in Main Pass. See Note 4, Dispositions.

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

	Year Ended December 31, 2014	2013	2012
		(millions)	
Income statement:			
Operating revenues	$ 859	$ 556	$ 431
Operating expenses	$ 503	$ 359	$ 254
Net income	$ 354	$ 194	$ 175

	December 31, 2014	2013
	(millions)	
Balance sheet:		
Current assets	$ 270	$ 314
Long-term assets	5,125	4,776
Current liabilities	(192)	(322)
Long-term liabilities	(165)	(69)
Net assets	$ 5,038	$ 4,699

10. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an “exit price” methodology, in line with how we believe a marketplace participant would value that asset or liability. Fair values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.

- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability positions with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.

- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets and liabilities. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 12, Risk Management and Hedging Activities, Credit Risk and Financial Instruments.

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 level of judgment involved in the most significant input in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil or natural gas futures) or over-the-counter, or OTC, instruments (such as natural gas contracts, costless commodity collars, crude oil or NGL swaps). The exchange traded instruments are generally executed on the NYMEX exchange with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk. To mitigate a portion of this risk and to manage commodity price risk related primarily to owned natural gas storage and pipeline assets, we engage in natural gas asset based trading and marketing, and we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

We also engage in the business of trading energy related products and services, which exposes us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third-party pricing services, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming 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 periodically use interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our fixed-rate debt for floating rate debt or floating rate debt for fixed-rate debt. The 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 interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Benefits

We offer certain eligible executives the opportunity to participate in DCP Midstream LP’s Non-Qualified Executive Deferred Compensation Plan, or the EDC Plan. All amounts contributed to and earned by the EDC Plan’s investments are held in a trust account, which is managed by a third-party service provider. The trust account is invested in short-term money market securities and mutual funds. These investments are recorded at fair value, with any changes in fair value being recorded as a gain or loss in the consolidated statements of operations. Given that the value of the short-term money market securities and mutual funds are publicly traded and for which market prices are readily available, these investments are classified within Level 1.

Nonfinancial Assets and Liabilities

We utilize fair value to perform impairment tests as required on our property, plant and equipment; goodwill; and long-lived intangible assets. Assets and liabilities acquired in third party business combinations are recorded at their fair value as of the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3 in the event that we were required to measure and record such assets at fair value within our consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified within Level 3.

The following table presents the financial instruments carried at fair value on a recurring basis, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(millions)							
Current assets:								
Commodity derivatives (a)	$ 33	$ 108	$ 23	$ 164	$ 9	$ 29	$ 21	$ 59
Interest rate derivatives (a)	$ —	$ 1	$ —	$ 1	$ —	$ —	$ —	$ —
Short-term investments (b)	$ 25	$ —	$ —	$ 25	$ 28	$ —	$ —	$ 28
Long-term assets:								
Commodity derivatives (c)	$ 1	$ 19	$ 3	$ 23	$ —	$ 8	$ 2	$ 10
Mutual funds (d)	$ 14	$ —	$ —	$ 14	$ 4	$ —	$ —	$ 4
Current liabilities (e):								
Commodity derivatives	$ (22)	$ (57)	$ (45)	$ (124)	$ (9)	$ (43)	$ (10)	$ (62)
Interest rate derivatives	$ —	$ —	$ —	$ —	$ —	$ (2)	$ —	$ (2)
Long-term liabilities (f):								
Commodity derivatives	$ (2)	$ (1)	$ (12)	$ (15)	$ —	$ (1)	$ (1)	$ (2)
Interest rate derivatives	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(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 other long-term assets in our consolidated balance sheets.
(e) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.
(f) 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. Amounts transferred in and out of Level 1 and Level 2 are reflected at fair value as of the end of the period. During the years ended December 31, 2014 and 2013, there were no transfers from Level 1 to Level 2 of the fair value hierarchy. During the years ended December 31, 2014 and 2013, we had the following transfers from Level 2 to Level 1 of the fair value hierarchy:

	Year Ended December 31,	
	2014 (a)	2013
	(millions)	
Current assets	$ 3	$ —
Long-term assets	$ 1	$ —
Current liabilities	$ (4)	$ —
Long-term liabilities	$ (2)	$ —

(a) Financial instruments have moved from Level 2 to Level 1 due to the passage of time.

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 Level 3" and "Transfers out of Level 3" captions.

We manage our overall risk at the portfolio level and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforwards below, the gains or losses in the tables do not reflect the effect of our total risk management activities.

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(millions)			
Year Ended December 31, 2014 (a):				
Beginning balance	$ 21	$ 2	$ (10)	$ (1)
Net realized and unrealized gains (losses) included in earnings (b)	23	1	(41)	(11)
Transfers out of Level 3 (c)	—	—	—	—
Settlements	(21)	—	6	—
Ending balance	$ 23	$ 3	$ (45)	$ (12)
Net unrealized gains (losses) still held included in earnings (b)	$ 23	$ —	$ (45)	$ (11)
Year Ended December 31, 2013 (a):				
Beginning balance	$ 16	$ 3	$ (14)	$ —
Net realized and unrealized gains (losses) included in earnings (b)	20	(1)	(5)	(1)
Transfers out of Level 3 (c)	—	—	1	—
Settlements	(15)	—	8	—
Ending balance	$ 21	$ 2	$ (10)	$ (1)
Net unrealized gains (losses) still held included in earnings (b)	$ 21	$ —	$ (10)	$ (1)

(a) There were no purchases, issuances, sales of derivatives or transfers into Level 3 for the years ended December 31, 2014 and 2013.
(b) Represents the amount of total gains or losses for the period, included in trading and marketing gains, net, in the consolidated statements of operations attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3.
(c) Amounts transferred in and amounts transferred out of Level 3 are reflected at fair value as of the end of the period.

Quantitative Information and Fair Value Sensitivities Related to Level 3 Unobservable Inputs

We utilize the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach 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 these contracts.

Product Group	Fair Value (millions)	Forward Curve Range	
Assets:			
NGLs	$ 26	$0.17 – $1.05	Per gallon
Liabilities:			
NGLs	$ (57)	$0.15 – $1.12	Per gallon

Estimated Fair Value of Financial Instruments

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

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

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

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

The fair value of accounts receivable, accounts payable and short-term borrowings are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Derivative instruments are carried at fair value. We determine the fair value of our variable rate debt 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 debt based on quotes obtained from bond dealers. We classify the fair value of our outstanding debt balances within Level 2 of the fair value hierarchy. As of December 31, 2014, the carrying and fair value of our long-term debt, including current maturities of long-term debt, was $5,683 million and $5,951 million, respectively. As of December 31, 2013, the carrying and fair value of our long-term debt was $4,962 million and $5,169 million, respectively.

11. Financing

	December 31, 2014	December 31, 2013
	(millions)	
Commercial paper:		
DCP Midstream's short-term borrowings, weighted-average interest rate of 0.89% and 0.91%, respectively	$ 1,012	$ 965
DCP Partners' short-term borrowings, weighted-average interest rate of 1.14% as of December 31, 2013	—	335
DCP Midstream's debt securities:		
Senior notes:		
Issued October 2005, interest at 5.375% payable semiannually, due October 2015	200	200
Issued February 2009, interest at 9.750% payable semiannually, due March 2019 (a)	450	450
Issued March 2010, interest at 5.350% payable semiannually, due March 2020 (a)	600	600
Issued September 2011, interest at 4.750% payable semiannually, due September 2021	500	500
Issued August 2000, interest at 8.125% payable semiannually, due August 2030 (b)	300	300
Issued October 2006, interest at 6.450% payable semiannually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semiannually, due September 2037	450	450
Junior subordinated notes:		
Issued May 2013, interest at 5.850% payable semiannually, due May 2043	550	550
DCP Partners' debt securities:		
Issued September 2010, interest at 3.25% payable semiannually, due October 2015	250	250
Issued November 2012, interest at 2.50% payable semiannually, due December 2017	500	500
Issued March 2014, interest at 2.70% payable semiannually, due April 2019	325	—
Issued March 2012, interest at 4.95% payable semiannually, due April 2022	350	350
Issued March 2013, interest at 3.875% payable semiannually, due March 2023	500	500
Issued March 2014, interest at 5.60% payable semiannually, due April 2044	400	—
Fair value adjustments related to interest rate swap fair value hedges (a) (b)	29	30
Unamortized discount	(21)	(18)
Total debt	6,695	6,262
Current maturities of long-term debt	(450)	—
DCP Midstream short-term borrowings	(1,012)	(965)
DCP Partners short-term borrowings	—	(335)
Total long-term debt	$ 5,233	$ 4,962

(a) Prior to December 31, 2014, $50 million of debt associated with each of these note issuances was swapped to a floating rate obligation. These interest rate swap agreements were terminated in January 2015, and the remaining long-term fair value of approximately $1 million related to these swaps will be amortized as a reduction of interest expense through March 2019 and March 2020, respectively, the original maturity date of the debt.

(b) In December 2008, the swaps associated with this debt were terminated. The remaining long-term fair value of approximately $28 million related to the swaps is being amortized as a reduction to interest expense through August 2030, the original maturity date of the debt.

Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2014:

	Debt Maturities
	(millions)
2015	$ 450
2016	—
2017	500
2018	—
2019	775
Thereafter	3,950
	5,675
Fair value adjustments related to interest rate swap fair value hedges	29
Unamortized discount	(21)
Current maturities of long-term debt	(450)
Long-term debt	$ 5,233

DCP Midstream's Debt Securities — In May 2013, we issued $550 million principal amount of 5.85% Fixed-to-Floating Rate Junior Subordinated Notes, due May 2043, for proceeds of approximately $544 million, net of unamortized offering costs and expenses of $6 million. The net proceeds were used to repay short-term borrowings.

The DCP Midstream senior debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. The DCP Midstream senior debt securities are senior unsecured obligations, and are redeemable at a premium at our option. The underwriters' fees and related expenses are deferred in other long-term assets in the consolidated balance sheets and will be amortized over the term of the notes.

DCP Midstream's Commercial Paper Program — We have a commercial paper program, or the DCP Midstream Commercial Paper Program, under which we may issue unsecured commercial paper notes, or the Notes. The Notes may be borrowed, repaid and re-borrowed from time to time with the maximum aggregate principal amount of the Notes outstanding, combined with the amount outstanding under our $2 billion amended and restated revolving credit agreement, or the DCP Midstream Amended and Restated Revolving Credit Agreement, not to exceed $2 billion in the aggregate. As of December 31, 2014 and 2013, we had $1,012 million and $965 million, respectively, of commercial paper outstanding, which are included in short-term borrowings in the consolidated balance sheets. Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, we no longer have access to the DCP Midstream Commercial Paper Program. Our available liquidity under the DCP Midstream Commercial Paper Program will be replaced with borrowings under the DCP Midstream Amended and Restated Revolving Credit Agreement. As of February 24, 2015, we have no commercial paper outstanding.

DCP Midstream's Credit Facilities with Financial Institutions — In May 2014, we entered into the DCP Midstream Amended and Restated Revolving Credit Agreement, which matures in May 2019. The DCP Midstream Amended and Restated Revolving Credit Agreement replaced our previous credit agreement dated as of March 2, 2012, or the DCP Midstream Credit Facility, which had a total borrowing capacity of $2 billion and would have matured in March 2017. The DCP Midstream Amended and Restated Revolving Credit Agreement may be used to support our capital expansion program, for working capital requirements and other general corporate purposes, including acquisitions, as well as for letters of credit. There were no borrowings outstanding under the DCP Midstream Amended and Restated Revolving Credit Facility as of December 31, 2014.

As of December 31, 2014 and 2013, we had $6 million and $8 million in letters of credit outstanding, respectively. As of December 31, 2014, the available capacity under the DCP Midstream Amended and Restated Revolving Credit Agreement was $982 million, net of letters of credit, of which approximately $865 million was available for general working capital purposes. Our borrowing capacity may be limited by the DCP Midstream Amended and Restated Revolving Credit Agreement's financial covenant requirements. Except in the case of default, amounts borrowed under the DCP Midstream Amended and Restated Revolving Credit Agreement will not become due prior to the May 2019 maturity date.

Indebtedness under the DCP Midstream Amended and Restated Revolving Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.075% based on our 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 0.075% based on our credit rating. The DCP Midstream Amended and Restated Revolving Credit Agreement incurs an annual facility fee of 0.175% based on our credit rating. This fee is paid on drawn and undrawn portions of the DCP Midstream Amended and Restated Revolving Credit Agreement. Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, interest rates and fees under the DCP Midstream Amended and Restated Revolving Credit Agreement have increased.

The DCP Midstream Amended and Restated Revolving Credit Agreement requires us to maintain a consolidated leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA as defined) of not more than 5.0 to 1.0, and following the consummation of qualifying acquisitions (as defined), 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. As a result of the current commodity price environment, we expect to exceed our consolidated leverage ratio as of March 31, 2015. As of February 24, 2015 we have $948 million outstanding under the DCP Midstream Amended and Restated Revolving Credit Agreement. Subsequent to December 31, 2014, we and our owners have initiated a process to modify certain terms of the DCP Midstream Amended and Restated Revolving Credit Agreement. If successfully completed, the outcome of these discussions may impact the availability, capacity and the cost of the borrowings under the DCP Midstream Amended and Restated Revolving Credit Agreement. Should a modification not be obtained, the amount outstanding would become due. However, we have multiple alternatives in the event an amendment is not obtained including, but not limited to, drop down transactions with DCP Partners, the sale of certain investments held by us or the sale of assets. We believe one, or a combination, of these alternatives would be sufficient to address our ongoing liquidity needs.

DCP Partners' Commercial Paper Program — DCP Partners has a commercial paper program, or the DCP Partners Commercial Paper Program, under which DCP Partners may issue unsecured commercial paper notes, or the DCP Partners' Notes. The DCP Partners' Notes outstanding may be borrowed, repaid, and re-borrowed from time to time with the maximum aggregate principal amount of the notes outstanding, combined with the amount outstanding under DCP Partners' $1.25 billion amended senior unsecured revolving credit agreement, or the DCP Partners Amended and Restated Credit Agreement, not to exceed $1.25 billion in the aggregate. As of December 31, 2014, DCP Partners had no commercial paper outstanding. As of December 31, 2013, DCP Partners had $335 million of commercial paper outstanding which was included in short-term borrowings in the consolidated balance sheets. Subsequent to December 31, 2014, DCP Partners' credit rating has been lowered below investment grade. As a result of this ratings action, DCP Partners no longer has access to the DCP Partners Commercial Paper Program. Available liquidity under the DCP Partners Commercial Paper Program will be replaced with borrowings under the DCP Partners Amended and Restated Credit Agreement, which had $89 million outstanding as of February 24, 2015.

DCP Partners' Credit Facilities with Financial Institutions — In May 2014, DCP Partners entered into the DCP Partners Amended and Restated Credit Agreement. The DCP Partners Amended and Restated Credit Agreement replaced DCP Partners' previous credit agreement dated as of November 10, 2011, or the DCP Partners Credit Agreement, which had a total borrowing capacity of $1 billion and would have matured in November 2016. The DCP Partners Amended and Restated Credit Agreement will be used for working capital requirements and other general partnership purposes including acquisitions. As of December 31, 2014 and 2013, DCP Partners had $1 million of letters of credit issued and outstanding under the DCP Partners Amended and Restated Credit Agreement and the DCP Partners Credit Agreement, respectively. As of December 31, 2014, the unused capacity under the DCP Partners Amended and Restated Credit Agreement was $1,249 million, which is net of letters of credit. DCP Partners' borrowing capacity may be limited by the DCP Partners Amended and Restated Credit Agreement's financial covenant requirements. Except in the case of default, amounts borrowed under the DCP Partners Amended and Restated Credit Agreement will not become due prior to the May 2019 maturity date.

Indebtedness under the DCP Partners Amended and Restated Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.275% based on DCP Partners' current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.275% based on DCP Partners' current credit rating. The DCP Partners Amended and Restated Credit Agreement incurs an annual facility fee of 0.225% based on DCP Partners' current credit rating. This fee is paid on drawn and undrawn portions of the DCP Partners Amended and Restated Credit Agreement.

The DCP Partners Amended and Restated Credit Agreement requires DCP Partners to maintain a leverage ratio (the ratio of DCP Partners' consolidated indebtedness to its consolidated EBITDA, in each case as defined) of not more than 5.0 to 1.0, and following consummation of qualifying acquisitions, not more than 5.5 to 1.0, on a temporary basis for three consecutive quarters, including the quarter in which such acquisition is consummated. Further, DCP Partners' cost of borrowing under the DCP Partners Amended and Restated Credit Agreement is determined by a ratings based pricing grid. Subsequent to December 31, 2014, DCP Partners' credit rating has been lowered below investment grade. As a result of this ratings action, interest rates and fees under the DCP Partners Amended and Restated Credit Agreement have increased.

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

In March 2013, DCP Partners issued $500 million of 3.875% 10-year Senior Notes, due March 2023. DCP Partners received proceeds of $490 million, net of underwriters' fees, related expenses and unamortized discounts, which were used to fund a portion of the acquisition of an additional 46.67% interest in the Eagle Ford system. Interest on the notes is paid semiannually on March 15 and September 15 of each year, and the first payment occurred on September 15, 2013. The notes will mature in March 2023, unless redeemed prior to maturity.

DCP Partners' debt securities are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under the DCP Partners Amended and Restated Credit Agreement. DCP Partners is 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 DCP Partners' 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.

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

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

In August 2013, DCP Partners issued 9,000,000 of its common units to the public at $50.04 per unit. DCP Partners received proceeds of $434 million, net of offering costs.

In June 2013, DCP Partners filed a shelf registration statement on Form S-3, or the June 2013 shelf registration statement, with the SEC with a maximum offering price of $300 million, which became effective on June 27, 2013. The June 2013 shelf registration statement allowed DCP Partners to issue additional common units. In November 2013, DCP Partners entered into an equity distribution agreement, or the 2013 equity distribution agreement, related to the June 2013 shelf registration statement, with a group of financial institutions as sales agents. The 2013 equity distribution agreement provided for the offer and sale from time to time, through DCP Partners' sales agents, of common units having an aggregate offering amount of up to $300 million. During the year ended December 31, 2014, DCP Partners issued 3,769,635 of its common units pursuant to the 2013 equity distribution agreement and received proceeds of $206 million, which is net of commissions and offering costs of $2 million. During the year ended December 31, 2013, DCP Partners issued 1,839,430 of its common units pursuant to the 2013 equity distribution agreement and received proceeds of $87 million, net of commissions and offering costs of $1 million. The proceeds were used to finance growth opportunities and for general partnership purposes. In connection with DCP Partners' entry into the 2014 equity distribution agreement, DCP Partners terminated the 2013 equity distribution agreement in September 2014. In October 2014, DCP Partners de-registered the common units that remained unsold under the 2013 equity distribution agreement at the time of its termination.

In March 2013, DCP Partners issued 12,650,000 of its common units to the public at $40.63 per unit. DCP Partners received proceeds of $494 million, net of offering costs.

In July 2012, DCP Partners closed a private placement of equity with a group of institutional investors in which DCP Partners sold 4,989,802 of its common units at a price of $35.55 per unit and received proceeds of $174 million, net of offering costs.

In March 2012, DCP Partners issued 5,148,500 of its common units at $47.42 per unit. DCP Partners received proceeds of $234 million, net of offering costs.

During the year ended December 31, 2013, DCP Partners issued 1,408,547 of its common units pursuant to the equity distribution agreement entered into in August 2011, or the 2011 equity distribution agreement. DCP Partners 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. During the year ended December 31, 2012, DCP Partners issued 1,147,654 of its common units under the 2011 equity distribution agreement, and received proceeds of $47 million, net of commissions and offering costs of $2 million. The 2011 equity distribution agreement provided for the offer and sale of common units having an aggregate offering amount of up to $150 million. In September 2013, DCP Partners de-registered the common units that remained unsold under this equity distribution agreement.

12. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

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. Our Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The following describes each of the risks that we manage.

Commodity Price Risk

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting. The risks, strategies and instruments used to mitigate such risks, as well as the method of accounting are discussed and summarized below.

Natural Gas Asset Based Trading and Marketing

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

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period 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.

DCP Partners Commodity Cash Flow Hedges

In order for our storage facilities to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. During construction or expansion of DCP Partners' storage caverns, DCP Partners may execute a series of derivative financial instruments to mitigate a portion of the risk associated with the forecasted purchase of natural gas when DCP Partners brings the storage caverns to operation. These derivative financial instruments may be designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixes the cash required to purchase base gas, the deferred losses or gains would remain in accumulated other comprehensive income, or AOCI, until the cavern is emptied and the base gas is sold. The balance in AOCI of DCP Partners' previously settled base gas cash flow hedges was in a loss position of $6 million as of December 31, 2014.

NGL Proprietary Trading

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations.

We employ established risk limits, policies and procedures to manage risks associated with our natural gas asset based trading and marketing and NGL proprietary trading.

Commodity Cash Flow Protection Activities at DCP Partners

DCP Partners is exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of its gathering, processing, sales and storage activities. For gathering, processing and storage services, DCP Partners may receive cash or commodities as payment for these services, depending on the contract type. DCP Partners enters into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with its gathering, processing and sales activities, thereby stabilizing its cash flows. DCP Partners has mitigated a portion of its expected commodity cash flow risk associated with its gathering, processing and sales activities through 2017 with commodity derivative instruments. DCP Partners' commodity derivative instruments used for its 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, DCP Partners has used crude oil swaps and costless commodity collars to mitigate a portion of its commodity price risk exposure for 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 DCP Partners' NGL hedges from 2014 through 2016 are direct product hedges with us. When its crude oil swaps become short-term in nature, DCP Partners has periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. DCP Partners' crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange DCP Partners' floating price risk for a fixed price. DCP Partners also utilizes crude oil costless commodity collars that minimize its floating price risk by establishing a fixed price floor and a fixed price ceiling. However, the type of instrument that DCP Partners uses to mitigate a portion of its risk may vary depending on DCP Partners' risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected in the current period within our consolidated statements of operations as trading and marketing gains, net.

Interest Rate Risk

We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to convert our floating rate debt to fixed-rate debt or to convert our fixed-rate debt to floating rate debt. Our primary goals include: (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates.

Prior to June 30, 2014, DCP Partners had interest rate swap agreements with notional values totaling $150 million, which were accounted for under the mark-to-market method of accounting and repriced prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, DCP Partners paid fixed rates ranging from 2.94% to 2.99%, and received interest payments based on the one-month LIBOR. These interest rate swap agreements settled in June 2014. Prior to August 2013, these interest rate swaps were designated as cash flow hedges whereby the effective portions of changes in fair value were recognized in AOCI in the consolidated balance sheets. In March 2014, DCP Partners paid down a portion of the balance outstanding under the DCP Partners Commercial Paper Program and reclassified the remaining loss of $1 million in AOCI into earnings as interest expense, net.

In conjunction with the issuance of DCP Partners' 4.95% Senior Notes in March 2012, DCP Partners entered into forward-starting interest rate swap agreements to reduce its exposure to market rate fluctuations prior to issuance. These derivative financial instruments were designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixed the rate DCP Partners would pay on a portion of its 4.95% Senior Notes, the deferred loss in AOCI will be amortized into interest expense through the maturity of the notes in 2022. The balance in AOCI of these cash flow hedges was in a loss position of $4 million as of December 31, 2014.

In July 2014, we entered into an interest rate swap agreement to convert $50 million of fixed-rate debt securities issued in February 2009 to floating rate debt. Additionally, in July 2014, we entered into an interest rate swap agreement to convert $50 million of fixed-rate debt securities issued in March 2010, to floating rate debt. The interest rate fair value hedges associated with each of these interest rate swap agreements are at a floating rate based on one month LIBOR, which resets monthly and are paid semi-annually through the expiration of the securities in March 2019 and March 2020, respectively. These swap agreements meet conditions that permit the assumption of no ineffectiveness. As such, for the life of the swap agreements no ineffectiveness will be recognized. These interest rate swap agreements were terminated in January 2015, and the remaining long-term fair value relative to these interest rate swap agreements will be reclassified to interest expense, net through March 2019 and March 2020, respectively, the original maturity date of the debt, as the underlying transactions impact earnings.

We previously had interest rate cash flow hedges and fair value hedges in place that were terminated in 2000 and 2008, respectively. As a result, the remaining net loss deferred in AOCI relative to these cash flow hedges and the remaining net loss included in long-term debt relative to these fair value hedges will be reclassified to interest expense, net through August 2030, the original maturity date of the debt, as the underlying transactions impact earnings.

Credit Risk

Our principal customers range from large, natural gas marketers to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Prior to December 31, 2014, approximately 35% of our NGL production was committed to Phillips 66 and CPChem, under 15-year contracts, the primary production commitment of which expired in December 2014 and began a wind down period and expires in January 2019. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

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

- In the event that we or DCP Partners were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties would have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.

- In some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. For example, if we were to fail to make a required interest or principal payment on a debt instrument, above a predefined threshold level, and after giving effect to any applicable notice or grace period as defined in the ISDA contracts, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative positions.

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or interest rate swap instruments are in either a net asset or net liability position. Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features. As of December 31, 2014, we had less than $1 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position 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, 2014, if a credit-risk related event were to occur, we may be required to post additional collateral. Although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2014, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position.

Collateral

As of December 31, 2014, we had cash deposits with counterparties of $35 million, included in other current assets in the consolidated balance sheets, to secure our obligations to provide future services or to perform under financial contracts. Additionally, as of December 31, 2014, we held cash of $9 million, included in other current liabilities in the consolidated balance sheet, related to cash postings by third parties and letters of credit of $79 million from counterparties to secure their future performance under financial or physical contracts. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, trading and hedging contracts. In many cases, we and our counterparties have publicly disclosed credit ratings, which may impact the amounts of collateral requirements.

Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

Offsetting

Certain of our derivative instruments are subject to a master netting or similar arrangement, whereby we may elect to settle multiple positions with an individual counterparty through a single net payment. Each of our individual derivative instruments are presented on a gross basis on the consolidated balance sheets, regardless of our ability to net settle our positions. Instruments that are governed by agreements that include net settle provisions allow final settlement, when presented with a termination event, of outstanding amounts by extinguishing the mutual debts owed between the parties in exchange for a net amount due. We have trade receivables and payables associated with derivative instruments, subject to master netting or similar agreements, which are not included in the table below. The following summarizes the gross and net amounts of our derivative instruments:

	December 31, 2014				December 31, 2013		
	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet: Financial Instruments	Amounts Not Offset in the Balance Sheet: Cash Collateral Pledged/ (Received) (a)	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet – Financial Instruments (b)	Net Amount
				(millions)			
Assets:							
Commodity derivative instruments	$ 187	$ —	$ (9)	$ 178	$ 69	$ (2)	$ 67
Interest rate derivative instruments	$ 1	$ —	$ —	$ 1	$ —	$ —	$ —
Liabilities:							
Commodity derivative instruments	$ (139)	$ —	$ —	$ (139)	$ (64)	$ 2	$ (62)
Interest rate derivative instruments	$ —	$ —	$ —	$ —	$ (2)	$ —	$ (2)

(a) Included in other current liabilities in the consolidated balance sheets.

(b) 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, those that are marked to market each period, and the location of each within our consolidated balance sheets, by major category, is summarized below:

Balance Sheet Line Item	December 31, 2014	December 31, 2013	Balance Sheet Line Item	December 31, 2014	December 31, 2013
	(millions)			(millions)	
Derivative Assets Designated as Hedging Instruments:			**Derivative Liabilities Designated as Hedging Instruments**:		
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments — current	$ 1	$ —	Unrealized losses on derivative instruments — current	$ —	$ —
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	—
	$ 1	$ —		$ —	$ —
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments**:		
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)
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments — current	$ 164	$ 59	Unrealized losses on derivative instruments — current	$ (124)	$ (62)
Unrealized gains on derivative instruments — long-term	23	10	Unrealized losses on derivative instruments — long-term	(15)	(2)
	$ 187	$ 69		$ (139)	$ (64)

The following table summarizes the balance and activity within AOCI relative to our interest rate and commodity derivatives, net of noncontrolling interest, for the year ended December 31, 2014:

	Interest Rate Derivatives		Commodity Derivatives	Total
			(millions)	
Net deferred losses in AOCI, beginning balance	$ (3)		$ (3)	$ (6)
Gains recognized in AOCI on derivatives — effective portion	—		—	—
Losses reclassified from AOCI — effective portion	1	(a)	—	1
Net deferred losses in AOCI, ending balance	$ (2)		$ (3)	$ (5)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ —		$ —	$ —

(a) Included in interest expense, net in our consolidated statements of operations.

For the year ended December 31, 2014, no derivative gains or losses were recognized in trading and marketing gains, net and interest expense, net in our consolidated statements of operations attributable to the ineffective portion of our derivative instruments, as a result of exclusion 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 balance and activity within AOCI relative to our interest rate and commodity derivatives, net of noncontrolling interest, for the year ended December 31, 2013:

	Interest Rate Derivatives		Commodity Derivatives		Total
			(millions)		
Net deferred losses in AOCI, beginning balance	$ (4)		$ (5)		$ (9)
Gains recognized in AOCI on derivatives — effective portion	—		—		—
Losses reclassified from AOCI — effective portion	1	(a)	2	(b)	3
Net deferred losses in AOCI, ending balance	$ (3)		$ (3)		$ (6)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ (1)		$ —		$ (1)

(a) Included in interest expense, net in our consolidated statements of operations.

(b) Included in noncontrolling interest in our consolidated balance sheets, as a result of changes in our ownership interest in DCP Partners.

For the year ended December 31, 2013, no derivative gains or losses were recognized in trading and marketing gains, net and interest expense, net in our consolidated statements of operations attributable to the ineffective portion of our derivative instruments, as a result of exclusion from effectiveness testing or as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

Changes in value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the consolidated statements of operations. The following summarizes these amounts and the location within the consolidated statements of operations that such amounts are reflected:

	Year Ended December 31,		
Commodity Derivatives: Statement of Operations Line Item	**2014**	**2013**	**2012**
		(millions)	
Realized gains	$ 45	$ 31	$ 86
Unrealized gains	43	5	—
Trading and marketing gains, net	$ 88	$ 36	$ 86

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 derivative positions, as well as the number of outstanding contracts 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 table below. Additionally, relative to the hedging of certain of our storage and/or transportation assets, we may execute basis transactions for natural gas, which may result in a net long/short position of zero. This table also presents our net long or short natural gas basis swap positions separately from our net long or short natural gas positions.

	December 31, 2014								
	Crude Oil		Natural Gas		Natural Gas Liquids			Natural Gas Basis Swaps	
Year of Expiration	Net Short Position (Bbls) (a)	Number of Contracts	Net Short Position (MMBtu) (b)	Number of Contracts	Net Short Position (Bbls)	Number of Contracts		Net Long (Short) Position (MMBtu)	Number of Contracts
2015	(1,091,000)	115	(18,882,800)	238	(21,236,472)	336	(c)	9,200,000	66
2016	(544,000)	19	(3,830,000)	2	(4,946,778)	23	(d)	(1,830,000)	10
2017	—	—	(6,387,500)	4	(2,700,000)	1	(e)	—	—

(a) Bbls represents barrels.
(b) MMBtu represents one million British thermal units.
(c) Includes 41 physical index based derivative contracts totaling (20,649,707) Bbls.
(d) Includes 2 physical index based derivative contracts totaling (5,400,000) Bbls.
(e) Includes 1 physical index based derivative contracts totaling (2,700,000) Bbls.

	December 31, 2013								
	Crude Oil		Natural Gas		Natural Gas Liquids			Natural Gas Basis Swaps	
Year of Expiration	Net Short Position (Bbls)	Number of Contracts	Net (Short) Long Position (MMBtu)	Number of Contracts	Net (Short) Long Position (Bbls)	Number of Contracts		Net Long Position (MMBtu)	Number of Contracts
2014	(1,323,250)	448	(19,102,550)	273	(19,991,853)	445	(a)	25,065,000	105
2015	(465,000)	51	2,737,500	28	703,344	12		1,875,000	4
2016	(498,000)	14	—	—	—	—		—	—

(a) Includes 49 physical index based derivative contracts totaling (20,580,664) Bbls.

DCP Partners periodically enters into interest rate swap agreements to mitigate a portion of its floating rate interest exposure. As of December 31, 2013, DCP Partners had interest rate swaps outstanding with individual notional values of $70 million and $80 million, which, in aggregate, exchanged $150 million of DCP Partners’ floating rate obligation to a fixed rate obligation through June 2014. These interest rate swap agreements settled in June 2014.

13. Equity-Based Compensation

We recorded equity-based compensation expense as follows, the components of which are further described below:

	Year Ended December 31, 2014	2013	2012
		(millions)	
DCP Midstream, LLC Long-Term Incentive Plan	$ 13	$ 18	$ 14
DCP Partners' Long-Term Incentive Plan (DCP Partners' LTIP)	1	2	2
Total	$ 14	$ 20	$ 16

	Vesting Period (years)	Unrecognized Compensation Expense at December 31, 2014 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream LTIP:				
Strategic Performance Units (SPUs)	3	$ 5	0% - 15%	2
Phantom Units	1 – 3	$ 4	0% - 14%	2

DCP Midstream LTIP — Under the DCP Midstream LTIP, or LTIP, awards may be granted to our key employees. The DCP Midstream LTIP provides for the grant of Strategic Performance Units, or SPUs, and Phantom Units. The SPUs and Phantom Units consist of a notional unit based on the value of common shares or units of Phillips 66, Spectra Energy and DCP Partners. Each award provides for the grant of dividend or distribution equivalent rights, or DERs. The LTIP is administered by the compensation committee of our board of directors. All awards are subject to cliff vesting.

Strategic Performance Units — The number of SPUs that will ultimately vest range in value of up to 200% of the outstanding SPUs, depending on the achievement of specified performance targets over a three year period. The final performance payout is determined by the compensation committee of our board of directors. The DERs are paid in cash at the end of the performance period. The following tables presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2012	255,975	$ 34.10	
Granted	173,129	$ 36.98	
Forfeited	(20,067)	$ 35.34	
Vested (a)	(141,650)	$ 30.35	
Outstanding at December 31, 2012	267,387	$ 37.86	
Granted	123,682	$ 41.01	
Forfeited	(43,658)	$ 38.71	
Vested (b)	(116,511)	$ 38.02	
Outstanding at December 31, 2013	230,900	$ 39.30	
Granted	116,790	$ 54.05	
Forfeited	(13,828)	$ 40.75	
Vested (c)	(114,499)	$ 37.72	
Outstanding at December 31, 2014	219,363	$ 47.89	$ 46.57
Expected to vest	203,142	$ 47.39	$ 46.57

(a) The 2010 grants vested at 130%.
(b) The 2011 grants vested at 142%.
(c) The 2012 grants vested at 115%.

The estimate of SPUs that are expected to vest is based on highly subjective assumptions that could change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amounts 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 for unit-based awards related to the strategic performance units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested or paid in cash in 2012	141,650	$ 8	$ 14
Vested or paid in cash in 2013	116,511	$ 8	$ 7
Vested or paid in cash in 2014	114,499	$ 7	$ 8

Phantom Units — The DERs are paid quarterly in arrears. The following table presents information related to Phantom Units:

	Units	Grant Date Weighted-Average Price	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2012	222,970	$ 34.68	
Granted	175,490	$ 37.14	
Forfeited	(18,590)	$ 35.34	
Vested	(139,670)	$ 31.98	
Outstanding at December 31, 2012	240,200	$ 38.00	
Granted	134,427	$ 41.78	
Forfeited	(23,215)	$ 39.81	
Vested	(143,890)	$ 38.10	
Outstanding at December 31, 2013	207,522	$ 40.18	
Granted	122,650	$ 53.73	
Forfeited	(11,130)	$ 41.96	
Vested	(147,840)	$ 42.10	
Outstanding at December 31, 2014	171,202	$ 48.11	$ 46.46
Expected to vest	159,659	$ 47.71	$ 46.48

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

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested or paid in cash in 2012	139,670	$ 6	$ 9
Vested or paid in cash in 2013	143,890	$ 5	$ 7
Vested or paid in cash in 2014	147,840	$ 5	$ 5

DCP Partners' LTIP — Under DCP Partners' 2005 LTIP, which was adopted by DCP Midstream GP, LLC, equity instruments may be granted to key employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The DCP Partners' 2005 LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. The 2005 LTIP phantom units consist of a notional unit based on the value of DCP Partners' common units. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the DCP Partners' 2005 LTIP. Awards that are canceled or forfeited, or are withheld to satisfy DCP Midstream GP, LLC's tax withholding obligations, are available for delivery pursuant to other awards. On February 15, 2012, the board of directors of DCP Midstream GP, LLC adopted a 2012 LTIP for employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The 2012 LTIP provides for the grant of phantom units and DERs. The 2012 LTIP phantom units consist of a notional unit based on the value of common units or shares of Phillips 66 and Spectra Energy. The LTIPs were administered by the compensation committee of DCP Midstream GP, LLC's board of directors through 2012, and by DCP Midstream GP, LLC's board of directors beginning in 2013. Awards are issued under both LTIPs and all awards are subject to cliff vesting.

Since DCP Partners has the intent and ability to settle certain awards within its control in units, DCP Partners classifies them as equity awards based on their fair value. The fair value of DCP Partners' equity awards is determined based on the closing price of DCP Partners' common units at the grant date. Compensation expense on equity awards is recognized ratably over each vesting period. DCP Partners accounts for other awards which are subject to settlement in cash, including DERs, as liability awards. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-measured each reporting period for all awards outstanding until the units are vested. The fair value of all liability awards is determined based on the closing price of DCP Partners' common units at each measurement date.

As of December 31, 2014, there was less than $1 million of unrecognized compensation expense related to DCP Partners LTIP awards.

14. Benefits

All Company employees who have reached the age of 18 and work at least 20 hours per week are eligible for participation in our 401(k) and retirement plan, to which we contribute a range of 4% to 7% of each eligible employee's qualified earnings to the retirement plan, based on years of service. Additionally, we match employees' contributions in the 401(k) plan up to 6% of qualified earnings. During the years ended December 31, 2014, 2013 and 2012, we expensed plan contributions of $30 million, $28 million and $27 million, respectively.

We offer certain eligible executives the opportunity to participate in the EDC Plan. The EDC Plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions. The EDC Plan also has make-whole provisions for plan participants who may otherwise be limited in the amount that we can contribute to the 401(k) plan on the participant's behalf. During the third quarter of 2013, we liquidated the net cash surrender value of our company owned life insurance policies, in order to change service providers, and received proceeds of $29 million. We re-invested these proceeds with a new service provider in the fourth quarter of 2013. Under the new service plan, all amounts contributed to and earned by the EDC Plan's investments are held in a trust account for the benefit of the EDC Plan participants, or general creditors in the event of our insolvency, as defined in the trust agreement. The trust assets and liability to the EDC Plan participants are part of our general assets and liabilities, respectively.

15. Income Taxes

We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state and local taxes of the limited liability company and other subsidiaries.

The State of Texas imposes a margin tax that is assessed at 0.95% of taxable margin apportioned to Texas for the year ended December 31, 2014, 0.975% for the year ended December 31, 2013 and 1% for the year ended December 31, 2012. Accordingly, we have recorded current tax expense for the Texas margin tax.

Income tax expense consisted of the following:

	Year Ended December 31,		
	2014	2013	2012
		(millions)	
Current:			
State income tax expense	$ (2)	$ (6)	$ (3)
Deferred:			
Federal income tax (expense) benefit	—	(1)	3
State income tax expense	(9)	(3)	(2)
Total income tax expense	$ (11)	$ (10)	$ (2)

We had net long-term deferred tax liabilities of $105 million and $96 million as of December 31, 2014 and 2013, respectively. The net long-term deferred tax liabilities are included in deferred income taxes on the consolidated balance sheets. The deferred tax liabilities of $156 million and $144 million as of December 31, 2014 and 2013, respectively, are primarily associated with depreciation and amortization related to the acquired intangible assets and property, plant and equipment. Offsetting the deferred tax liabilities are deferred tax assets related to the net operating loss of an affiliate corporation of approximately $51 million and $48 million as of December 31, 2014 and 2013, respectively. The net operating losses begin expiring in 2027. We expect to fully utilize the net operating loss carryovers, and, accordingly we have not provided a valuation allowance for the net deferred tax asset.

Our effective tax rate differs from statutory rates primarily due to our structure as a limited liability company, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states. Additionally, one of our subsidiaries is a tax paying entity for federal income tax purposes.

16. Commitments and Contingent Liabilities

Litigation — The midstream industry has seen a number of class action lawsuits involving royalty disputes, mismeasurement and mispayment allegations. We are currently named as defendants in some of these cases and customers have asserted individual audit claims related to mismeasurement and mispayment. Management believes we have meritorious defenses to these cases and, therefore, will continue to defend them vigorously. These claims, however, can be costly and time consuming to defend. We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business, including, from time to time, disputes with customers over various measurement and settlement issues.

Management currently believes that these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage and other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

General Insurance – Our insurance coverage is carried with an affiliate of Phillips 66, an affiliate of Spectra Energy and third-party insurers. Our insurance coverage includes: (1) general liability insurance covering third-party exposures; (2) statutory workers' compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired vehicles; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of real and personal property and includes business interruption; and (6) insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

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

We make expenditures in connection with environmental matters as part of our normal operations. As of December 31, 2014 and 2013, environmental liabilities included in the consolidated balance sheets as other current liabilities amounted to $5 million and $4 million, respectively. As of both December 31, 2014 and 2013, environmental liabilities included in the consolidated balance sheets as other long-term liabilities amounted to $9 million.

Operating Leases — We utilize assets under operating leases in several areas of operations. Consolidated rental expense, including leases with no continuing commitment, amounted to $31 million, $36 million and $36 million during the years ended December 31, 2014, 2013 and 2012, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows:

	Minimum Rental Payments (millions)
2015	$ 59
2016	35
2017	33
2018	31
2019	30
Thereafter	90
Total minimum lease payments	$ 278

17. Guarantees and Indemnifications

We periodically enter into agreements for the acquisition, contribution or divestiture of assets. These agreements contain indemnification provisions that may provide indemnity for environmental, tax, employment, outstanding litigation, breaches of representations, warranties and covenants, performance of DCP Partners or other liabilities related to the assets being acquired, contributed or divested. Claims may be made by third parties or DCP Partners under these indemnification agreements for various periods of time depending on the nature of the claim. The effective periods on these indemnification provisions generally have terms of one to 15 years, although some are longer. Our maximum potential exposure under these indemnification agreements can vary depending on the nature of the claim and the particular transaction. We are unable to estimate the total maximum potential amount of future payments under indemnification agreements due to several factors, including uncertainty as to whether claims will be made under these indemnities. We have issued guarantees and indemnifications for certain of our consolidated subsidiaries.

18. Supplemental Cash Flow Information

	Year Ended December 31,		
	2014	2013	2012
		(millions)	
Cash paid for interest, net of capitalized interest	$ 274	$ 229	$ 169
Cash paid for income taxes, net of income tax refunds received	$ 4	$ 6	$ 6
Non-cash investing and financing activities:			
Property, plant and equipment acquired with accounts payable	$ 145	$ 82	$ 158
Other non-cash changes in property, plant and equipment	$ 27	$ 77	$ 59

During the years ended December 31, 2014, 2013 and 2012, we received distributions from DCP Partners of $173 million, $116 million and $75 million, respectively, which have been eliminated in consolidation.

19. Subsequent Events

We have evaluated subsequent events occurring through February 26, 2015, the date the consolidated financial statements were issued.

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

In January 2015, we entered into a purchase and sale agreement with Mustang Gas Products, LLC to sell our approximate 44% membership interest in the Dover-Hennessey gas processing plant and gathering system, or Dover-Hennessey, for approximately $29 million, subject to customary purchase price adjustments. This transaction closed on January 30, 2015.

As part of an effort to reduce costs, we announced a reduction in force in January 2015 affecting approximately 20 percent of our corporate staff functions. With this corporate restructuring, we will also close or reduce the workforce of certain regional offices. We are also working on several other initiatives to either reduce costs or improve margins.

On January 29, 2015, DCP Partners announced that the board of directors of DCP Partners' general partner declared a quarterly distribution of $0.78 per unit, payable on February 13, 2015 to unitholders of record on February 9, 2015.

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