DCP Midstream, LLC
Condensed Consolidated Financial Statements for the Three Months Ended March 31, 2011 and 2010
(Unaudited)

DCP MIDSTREAM, LLC
CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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DCP MIDSTREAM, LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
(millions)

	March 31, 2011 (Unaudited)	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9	$ 8
Accounts receivable:		
Customers, net of allowance for doubtful accounts of $2 million each period	868	1,013
Affiliates	267	239
Other	20	18
Inventories	78	108
Unrealized gains on derivative instruments	214	144
Other	45	43
Total current assets	1,501	1,573
Property, plant and equipment, net	5,399	5,287
Investments in unconsolidated affiliates	156	159
Intangible assets, net	381	387
Goodwill	728	721
Unrealized gains on derivative instruments	49	25
Other long-term assets	96	86
Total assets	$ 8,310	$ 8,238
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 1,024	$ 1,105
Affiliates	89	79
Other	42	33
Short-term borrowings	385	187
Current maturities of long-term debt	—	250
Distributions payable to members	35	77
Unrealized losses on derivative instruments	263	180
Accrued taxes	86	60
Other	202	235
Total current liabilities	2,126	2,206
Deferred income taxes	97	135
Long-term debt	3,250	3,223
Unrealized losses on derivative instruments	101	65
Other long-term liabilities	122	128
Total liabilities	5,696	5,757
Commitments and contingent liabilities		
Equity:		
Members' interest	2,116	2,073
Accumulated other comprehensive loss	(12)	(13)
Total members' equity	2,104	2,060
Noncontrolling interest	510	421
Total equity	2,614	2,481
Total liabilities and equity	$ 8,310	$ 8,238

See Notes to Condensed Consolidated Financial Statements.

DCP MIDSTREAM, LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(millions)

	Three Months Ended March 31,	
	2011	**2010**
Operating revenues:		
Sales of natural gas and petroleum products	$ 2,226	$ 2,267
Sales of natural gas and petroleum products to affiliates	645	694
Transportation, storage and processing	91	91
Trading and marketing (losses) gains, net	(29)	20
Total operating revenues	2,933	3,072
Operating costs and expenses:		
Purchases of natural gas and petroleum products	2,153	2,278
Purchases of natural gas and petroleum products from affiliates	268	265
Operating and maintenance	158	133
Depreciation and amortization	105	103
General and administrative	75	56
Total operating costs and expenses	2,759	2,835
Operating income	174	237
Earnings from unconsolidated affiliates	5	9
Interest expense	(53)	(65)
Income before income taxes	126	181
Income tax expense	—	(2)
Net income	126	179
Net loss (income) attributable to noncontrolling interests	7	(14)
Net income attributable to members' interests	$ 133	$ 165

See Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Net income	$ 126	$ 179
Other comprehensive income (loss):		
Net unrealized losses on cash flow hedges	(1)	(8)
Reclassification of cash flow hedges into earnings	5	7
Total other comprehensive income (loss)	4	(1)
Total comprehensive income	130	178
Total comprehensive loss (income) attributable to noncontrolling interests	4	(13)
Total comprehensive income attributable to members' interests	$ 134	$ 165

See Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Cash flows from operating activities:		
Net income	$ 126	$ 179
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	105	103
Earnings from unconsolidated affiliates	(5)	(9)
Distributions from unconsolidated affiliates	8	15
Deferred income tax benefit	(2)	(2)
Equity based compensation	2	—
Other, net	2	2
Changes in operating assets and liabilities which provided (used) cash:		
Accounts receivable	114	153
Inventories	30	(4)
Net unrealized losses (gains) on derivative instruments	29	(8)
Accounts payable	(74)	(178)
Other	(39)	(58)
Net cash provided by operating activities	296	193
Cash flows from investing activities:		
Capital expenditures	(189)	(69)
Acquisitions, net of cash acquired	(40)	(22)
Investments in unconsolidated affiliates	—	(1)
Proceeds from sales of available-for-sale securities	1	10
Net cash used in investing activities	(228)	(82)
Cash flows from financing activities:		
Payment of dividends and distributions to members	(160)	(150)
Proceeds from debt	547	717
Payment of debt	(769)	(116)
Proceeds from issuance of common units by a subsidiary, net of offering costs	140	—
Commercial paper, net	198	—
Distributions paid to noncontrolling interests	(19)	(14)
Purchase of additional interest in a subsidiary	—	(4)
Deferred financing costs	(4)	(5)
Net cash (used in) provided by financing activities	(67)	428
Net change in cash and cash equivalents	1	539
Cash and cash equivalents, beginning of period	8	264
Cash and cash equivalents, end of period	$ 9	$ 803

See Notes to Condensed Consolidated Financial Statements.

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

	Members' Equity			
	Members' Interest	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interest	Total Equity
Balance, January 1, 2011	$ 2,073	$ (13)	$ 421	$ 2,481
Dividends and distributions	(118)	—	(19)	(137)
Issuance of common units by a subsidiary	28	—	112	140
Comprehensive income (loss):				
Net income	133	—	(7)	126
Net unrealized losses on cash flow hedges	—	(1)	—	(1)
Reclassifications of cash flow hedges into earnings	—	2	3	5
Total comprehensive income (loss)	133	1	(4)	130
Balance, March 31, 2011	$ 2,116	$ (12)	$ 510	$ 2,614
Balance, January 1, 2010	$ 2,020	$ (17)	$ 315	$ 2,318
Dividends and distributions	(177)	—	(15)	(192)
Purchase of additional interest in a subsidiary	—	—	(4)	(4)
Comprehensive income (loss):				
Net income	165	—	14	179
Net unrealized losses on cash flow hedges	—	(3)	(5)	(8)
Reclassifications of cash flow hedges into earnings	—	3	4	7
Total comprehensive income	165	—	13	178
Balance, March 31, 2010	$ 2,008	$ (17)	$ 309	$ 2,300

See Notes to Condensed 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 Spectra Energy Corp and its affiliates, or Spectra Energy, and 50% by ConocoPhillips and its affiliates, or ConocoPhillips. We operate in the midstream natural gas industry. Our primary operations consist of gathering, processing, compressing, transporting and storing of natural gas, and fractionating, transporting, gathering, treating, processing and storing of natural gas liquids, or NGLs, and/or condensate as well as marketing, from which we generate revenues primarily by trading and marketing natural gas and NGLs.

DCP Midstream Partners, LP, or DCP Partners, is a master limited partnership, of which a wholly-owned subsidiary of ours acts as general partner. As of March 31, 2011 and December 31, 2010, we owned an approximately 26% and 29% limited partner interest, respectively, in DCP Partners. Additionally, as of March 31, 2011 and December 31, 2010, we owned an approximately 1% general partner interest in DCP Partners, for both periods, as well as 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 exercise control over DCP Partners and we account for it as a consolidated subsidiary.

We are governed by a five member board of directors, consisting of two voting members from each parent company and our Chief Executive Officer and President, 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 Spectra Energy and ConocoPhillips board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Spectra Energy and ConocoPhillips.

These condensed consolidated financial statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective interim periods. Certain information and notes normally included in our annual financial statements have been condensed in or omitted from these interim financial statements. Operating results for the three months ended March 31, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011. These condensed consolidated financial statements should be read in conjunction with our consolidated financial statements for the year ended December 31, 2010. The December 31, 2010 balance sheet included in this report has been retrospectively adjusted to reflect changes to the preliminary purchase price allocation relating to DCP Partners' December 2010 acquisition of Marysville Hydrocarbons Holdings, LLC, or Marysville. See Note 3, Acquisitions, for further discussion of this adjustment.

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the condensed 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. These condensed 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 as the general partner 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. Recent Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2010-29 "Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations," **or ASU 2010-29** — In December 2010, the FASB issued ASU 2010-29 which amended Accounting Standards Codification, or ASC, Topic 805 "Business Combinations" to specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the year had occurred as of the beginning of the comparable prior annual reporting period only. The ASU also expands the supplemental pro forma disclosures under Topic 805 to include a description of the nature and the amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU 2010-29 is effective for business combinations for which the acquisition date is on or after January 1, 2011. The provisions of ASU 2010-29 impact only disclosures. We have not had any business combinations that fall under the guidance of ASU 2010-29 and consequently, there was no impact on our disclosures as a result of adoption.

ASU 2010-28 "Intangibles—Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts," **or ASU 2010-28** — In December 2010, the FASB issued ASU 2010-28 which amended ASC Topic 350 "Intangibles—Goodwill and Other." ASU 2010-28 requires an entity with reporting units that have carrying amounts that are zero or negative to assess whether it is more likely than not that the reporting units' goodwill is impaired. If the entity determines that it is more likely than not that the goodwill of one or more of its reporting units is impaired, the entity is required to perform Step 2 of the goodwill impairment test for those reporting unit(s) and record any resulting impairment as a cumulative-effect adjustment to beginning retained earnings. The provisions of ASU 2010-28 became effective for us on January 1, 2011. We do not have any reporting units that fall under the guidance of ASU 2010-28 and consequently, there was no effect on our condensed consolidated results of operations, cash flows or financial position as a result of adoption.

ASU 2010-06 "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," **or ASU 2010-06** — In January 2010, the FASB issued ASU 2010-06 which amended ASC Topic 820-10 "Fair Value Measurement and Disclosures — Overall." ASU 2010-06 requires new disclosures regarding transfers in and out of assets and liabilities measured at fair value classified within the valuation hierarchy as either Level 1 or Level 2 and information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3. ASU 2010-06 clarifies existing disclosures on the level of disaggregation required and inputs and valuation techniques. The provisions of ASU 2010-06 became effective for us on January 1, 2010, except for disclosure of information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3, which became effective for us on January 1, 2011. The provisions of ASU 2010-06 impact only disclosures and we have disclosed information in accordance with the provisions of ASU 2010-06 within these financial statements.

ASU 2009-13 "Revenue Recognition (Topic 605) Multiple-Deliverable Revenue Arrangements," **or ASU 2009-13** — In October 2009, the FASB issued ASU 2009-13 which amended ASC Topic 605 "Revenue Recognition." The ASU addresses the accounting for multiple-deliverable arrangements, to enable vendors to account for products or services separately rather than as a combined unit. ASU 2009-13 became effective for us on January 1, 2011 and there was no impact on our condensed consolidated results of operations, cash flows and financial position as a result of adoption.

3. Acquisitions

On March 24, 2011, DCP Partners acquired two NGL fractionation facilities in Weld County, Colorado, located in the Denver-Julesburg Basin, from a third party in a transaction accounted for as an asset acquisition. DCP Partners paid a purchase price of $30 million financed at closing with borrowings under DCP Partners' revolving credit facility, and received a post-closing purchase price adjustment of less than $1 million. The fractionation facilities are located on our processing plant sites and are operated by us.

On December 30, 2010, DCP Partners acquired all of the interests in Marysville. The acquisition involved three separate transactions with a number of parties. DCP Partners acquired a 90% interest in Marysville from Dart Energy Corporation, a 5% interest in Marysville from Prospect Street Energy, LLC and 100% of EE Group, LLC, which owned the remaining 5% interest in Marysville. DCP Partners paid a purchase price of $95 million plus $6 million for net working capital and other adjustments, for an aggregate purchase price of $101 million, subject to customary purchase price adjustments, for DCP Partners' 100% interest. The purchase was financed at closing with borrowings under DCP Partners revolving credit facility. $21 million of the purchase price has been deposited in an indemnity escrow to satisfy certain tax liabilities and provide for breaches of representations and warranties of the sellers.

On January 4, 2011, DCP Partners merged two wholly-owned subsidiaries of Marysville and converted the combined entity's organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggered tax liabilities, resulting from built-in tax gains recognized in the transaction, to become currently payable. Accordingly, $35 million of estimated deferred tax liabilities associated with this transaction and recorded at December 31, 2010, became current tax liabilities as of January 4, 2011 and are included in accrued taxes in our condensed consolidated balance sheet as of March 31, 2011.These tax liabilities are unrelated to the tax liabilities of Marysville for which an indemnity escrow has been established. These tax liabilities may be greater or less than the $35 million currently recorded in our balance sheet as of March 31, 2011.

We have updated our accounting for the Marysville business combination for the fair value of assets acquired and liabilities assumed including intangible assets, goodwill and property, plant and equipment. The December 31, 2010 balance sheet included in this report has been retrospectively adjusted to reflect the impact of this change. The purchase price allocation is preliminary and is based on initial estimates of fair values at the date of the acquisition. We are currently evaluating the preliminary purchase price allocation, which will be adjusted as additional information relative to the fair value of assets and liabilities becomes available. This allocation may change in subsequent financial statements, pending the final estimates of fair value and the final outcome of our estimated tax liabilities. The preliminary purchase price allocation as of December 31, 2010 compared to the preliminary purchase price allocation as of March 31, 2011 is as follows:

	December 31, 2010	March 31, 2011	Change
		(millions)	
Aggregate consideration	$ 101	$ 101	$ —
Cash	$ 3	$ 3	$ —
Accounts receivable	1	1	—
Inventory	6	5	(1)
Other current assets	1	1	—
Property, plant and equipment	130	58	(72)
Intangible assets	—	32	32
Goodwill	—	40	40
Other long-term assets	—	1	1
Deferred income taxes	(35)	(35)	—
Other current liabilities	(5)	(5)	—
Total preliminary purchase price allocation	$ 101	$ 101	$ —

4. Agreements and Transactions with Related Parties and Affiliates

Dividends and Distributions

During the three months ended March 31, 2011 and 2010, we paid tax distributions of $77 million and $71 million, respectively, based on estimated annual taxable income allocated to ConocoPhillips and Spectra Energy according to their respective ownership percentages at the date the distributions became due. During the three months ended March 31, 2011 and 2010, we declared and paid dividends of $83 million and $79 million, respectively, to Spectra Energy and ConocoPhillips, allocated in accordance with their respective ownership percentages.

During the three months ended March 31, 2011 and 2010, DCP Partners paid distributions of $18 million and $14 million, respectively, to its public unitholders.

ConocoPhillips

Long-Term NGL Purchases Contract and Transactions — We sell a portion of our residue gas and NGLs to ConocoPhillips. In addition, we purchase natural gas from and provide gathering, transportation and other services to ConocoPhillips. Approximately 40% of our NGL production is committed to ConocoPhillips and CP Chem, both related parties, under an existing 15-year contract, which expires in 2015. Should the contract not be renegotiated or renewed, it provides for a five year ratable wind-down period through 2020. The NGL contract also grants ConocoPhillips the right to purchase at index-based prices certain quantities of NGLs produced at processing plants that are acquired and/or constructed by us in the future in various counties in the Mid-Continent and Permian Basin regions, and the Austin Chalk area. We anticipate continuing to purchase and sell these commodities and provide these services to ConocoPhillips in the ordinary course of business.

On January 1, 2011, we entered into a 15-year gathering and processing agreement with ConocoPhillips, whereby ConocoPhillips has dedicated all of its natural gas production within an area of mutual interest in Oklahoma and Texas. This contract replaces and extends certain contracts that we previously had with ConocoPhillips.

Spectra Energy

Commodity Transactions — We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum 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 has propane supply agreements with Spectra Energy, effective through April 2012, which provide DCP Partners propane supply at its marine terminals for up to approximately 185 million gallons of propane annually. Additionally, DCP Partners has transportation agreements with Spectra Energy, effective through January 2012, which provide DCP Partners natural gas transportation of approximately 35 million cubic feet per day.

Transactions with DCP Partners

On January 1, 2011, we completed the sale of a 33.33% interest in the DCP Southeast Texas business to DCP Partners for $150 million, in a transaction among entities under common control. The transaction was financed at closing with proceeds from DCP Partners’ November 2010 public equity offering and borrowings under the DCP Partners’ revolving credit facility. The proceeds we received were used to pay down our short-term borrowings. The DCP Southeast Texas business is a fully integrated midstream business which includes 675 miles of natural gas pipelines, three natural gas processing plants totaling 380 MMcf/d of processing capacity, natural gas storage assets with 9 Bcf of existing storage capacity, and NGL market deliveries direct to Exxon Mobil and to Mont Belvieu via DCP Partners’ Black Lake NGL pipeline. The terms of the joint venture agreement provide that DCP Partners’ distributions from the joint venture for the first seven years related to storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to our and DCP Partners’ respective ownership interests in the DCP Southeast Texas business. We will continue to consolidate these assets in our financial statements, through our 66.67% interest in the joint venture and our consolidation of DCP Partners.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum 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:

	Three Months Ended March 31,	
	2011	**2010**
	(millions)	
ConocoPhillips:		
Sales of natural gas and petroleum products to affiliates	$ 628	$ 679
Transportation, storage and processing	$ 4	$ 6
Purchases of natural gas and petroleum products from affiliates	$ 130	$ 131
Operating and general and administrative expenses	$ 1	$ 1
Spectra Energy:		
Sales of natural gas and petroleum products to affiliates	$ 1	$ 1
Purchases of natural gas and petroleum products from affiliates	$ 103	$ 98
Operating and general and administrative expenses	$ 3	$ —
Unconsolidated affiliates:		
Sales of natural gas and petroleum products to affiliates	$ 16	$ 14
Transportation, storage and processing	$ 5	$ 6
Purchases of natural gas and petroleum products from affiliates	$ 35	$ 36

We had balances with related parties and affiliates as follows:

	March 31, 2011	December 31, 2010
	(millions)	
ConocoPhillips:		
Accounts receivable	$ 246	$ 221
Accounts payable	$ (57)	$ (46)
Other assets	$ 1	$ 2
Spectra Energy:		
Accounts receivable	$ 2	$ 2
Accounts payable	$ (8)	$ (20)
Other assets	$ —	$ 2
Unconsolidated affiliates:		
Accounts receivable	$ 19	$ 16
Accounts payable	$ (24)	$ (13)

5. Inventories

Inventories were as follows:

	March 31, 2011	December 31, 2010
	(millions)	
Natural gas	$ 14	$ 11
NGLs	64	97
Total inventories	$ 78	$ 108

6. Property, Plant and Equipment

Property, plant and equipment by classification is as follows:

	Depreciable Life	March 31, 2011	December 31, 2010
		(millions)	
Gathering and transmission systems	15 - 30 years	$ 5,494	$ 5,441
Processing, storage and terminal facilities	0 - 50 years	2,844	2,807
Other	0 - 30 years	260	253
Construction work in progress		659	545
Property, plant and equipment		9,257	9,046
Accumulated depreciation		(3,858)	(3,759)
Property, plant and equipment, net		$ 5,399	$ 5,287

Depreciation expense for the three months ended March 31, 2011 and 2010 was $99 million and $97 million, respectively. Interest capitalized on construction projects for the three months ended March 31, 2011 and 2010 was $5 million and $2 million, respectively.

7. Goodwill and Intangible Assets

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

	March 31, 2011	December 31, 2010
	(millions)	
Beginning of period	$ 721	$ 662
Acquisitions	7	59
End of period	$ 728	$ 721

Goodwill increased in 2011 approximately $7 million as a result of a purchase price adjustment related to the settlement of a contingent payment in conjunction with the acquisition of Michigan Pipeline & Processing, LLC.

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 condensed consolidated balance sheets as intangible assets, net, and are as follows:

	March 31, 2011	December 31, 2010
	(millions)	
Gross carrying amount	$ 523	$ 523
Accumulated amortization	(142)	(136)
Intangible assets, net	$ 381	$ 387

During the three months ended March 31, 2011 and 2010, we recorded amortization expense of $6 million for both periods. As of March 31, 2011, the remaining amortization periods ranged from three years to 24 years, with a weighted-average remaining period of approximately 19 years.

The weighted-average remaining amortization is 20 years for the $32 million of intangible assets acquired with our acquisition of Marysville.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization
	(millions)
Remainder of 2011	$ 19
2012	26
2013	26
2014	20
2015	19
Thereafter	271
Total	$ 381

8. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, as well as short-term and restricted investments, which are measured at fair value. Fair values are generally based upon quoted market prices, 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. 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 position 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 10, 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 the input that requires the highest degree of judgment in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include 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 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 based upon observable data. In instances where we utilize an interpolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 2. In certain limited instances, we may extrapolate based upon the last readily observable data, developing our own expectation of fair value. To the extent that we have utilized extrapolated data, 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 expose 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 use interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt or our fixed rate debt for floating 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 our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Long-Term Assets

We offer certain eligible executives the opportunity to participate in DCP Midstream LP’s Non-Qualified Executive Deferred Compensation plan, and have elected to fund a portion of this participation by investing in company owned life insurance policies. These investments are reflected within our condensed consolidated balance sheets as long-term assets and are considered financial instruments that are recorded at fair value, with any changes in fair value being recorded as a gain or loss in the condensed consolidated statements of operations. Given that the value of these life insurance policies is determined based upon certain publicly traded mutual funds whose value is readily observable in the marketplace, these investments are classified within Level 2.

Nonfinancial Assets and Liabilities

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

We utilize fair value on a recurring basis to measure our contingent consideration that is a result of certain acquisitions. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and are classified within Level 3.

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

	March 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(millions)							
Current assets (a):								
Commodity derivatives	$ 87	$ 59	$ 68	$ 214	$ 41	$ 52	$ 50	$ 143
Interest rate derivatives	$ —	$ —	$ —	$ —	$ —	$ 1	$ —	$ 1
Long-term assets:								
Commodity derivatives (b)	$ 25	$ 11	$ 13	$ 49	$ 11	$ 4	$ 10	$ 25
Company owned life insurance (c)	$ —	$ 20	$ —	$ 20	$ —	$ 16	$ —	$ 16
Current liabilities:								
Commodity derivatives (d)	$ (91)	$ (86)	$ (69)	$ (246)	$ (45)	$ (73)	$ (45)	$ (163)
Interest rate derivatives (d)	$ —	$ (17)	$ —	$ (17)	$ —	$ (17)	$ —	$ (17)
Acquisition related contingent consideration (e)	$ —	$ —	$ —	$ —	$ —	$ —	$ (2)	$ (2)
Long-term liabilities (f):								
Commodity derivatives	$ (29)	$ (63)	$ (3)	$ (95)	$ (14)	$ (40)	$ (1)	$ (55)
Interest rate derivatives	$ —	$ (6)	$ —	$ (6)	$ —	$ (10)	$ —	$ (10)

(a) Included in current unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(b) Included in long-term unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(c) Included in other long-term assets in our condensed consolidated balance sheets.
(d) Included in current unrealized losses on derivative instruments in our condensed consolidated balance sheets.
(e) Included in other current liabilities in our condensed consolidated balance sheets as of December 31, 2010.
(f) Included in long-term unrealized losses on derivative instruments in our condensed consolidated balance sheets.

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our condensed consolidated balance sheets for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. 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. 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)			
Three months ended March 31, 2011 (a):				
Beginning balance	$ 50	$ 10	$ (45)	$ (1)
Net realized and unrealized gains (losses) included in earnings	42	3	(67)	(2)
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	(8)	—	1	—
Settlements	(16)	—	42	—
Ending balance	$ 68	$ 13	$ (69)	$ (3)
Net unrealized gains (losses) still held included in earnings (c)	$ 38	$ 3	$ (39)	$ —
Three months ended March 31, 2010:				
Beginning balance	$ 73	$ 18	$ (88)	$ (6)
Net realized and unrealized gains (losses) included in earnings	11	(7)	1	—
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	(3)	—	—	—
Purchases, issuances and settlements, net	(36)	—	36	—
Ending balance	$ 45	$ 11	$ (51)	$ (6)
Net unrealized gains (losses) still held included in earnings (c)	$ 7	$ (7)	$ (5)	$ 1

(a) There were no purchases, issuances and sales for the three months ended March 31, 2011.
(b) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(c) Represents the amount of total gains or losses for the period, included in trading and marketing (losses) gains, net, attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3 that are still held as of March 31, 2011 and 2010.

	Contingent Consideration
	Current Liabilities
	(millions)
Three months ended March 31, 2011:	
Beginning balance	$ 2
Additions	—
Settlements	(2)
Re-measurement (a)	—
Ending balance	$ —
Three months ended March 31, 2010:	
Beginning balance	$ —
Additions	1
Re-measurement (a)	—
Ending balance	$ 1

(a) Recognized within operating expense in the condensed consolidated statement of operations.

We had no significant transfers between Level 1 and Level 2 during the three months ended March 31, 2011.

Estimated Fair Value of Financial Instruments

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. Unrealized gains and unrealized losses on derivative instruments are carried at fair value. As of March 31, 2011, the carrying and fair value of our long-term debt was $3,250 million and $3,570 million, respectively. As of December 31, 2010, the carrying and fair value of our long-term debt, including current maturities of long-term debt, was $3,473 million and $3,790 million, respectively. 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.

9. Financing

	March 31, 2011	December 31, 2010
	(millions)	
Short-term borrowings	$ 385	$ 187
DCP Midstream's debt securities:		
Issued January 2001, interest at 6.875% payable semiannually, due February 2011 (a)	—	250
Issued November 2008, interest at 9.700% payable semiannually, due December 2013	250	250
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	450	450
Issued March 2010, interest at 5.350% payable semiannually, due March 2020	600	600
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
DCP Partners' debt securities:		
Issued September 2010, interest at 3.25%, payable semiannually, due October 2015	250	250
DCP Partners' credit facility revolver, weighted-average variable interest rate of 0.73% and 1.14%, respectively, due June 2012 (c)	426	398
Fair value adjustments related to interest rate swap fair value hedges (a) (b)	36	37
Unamortized discount	(12)	(12)
Total debt	3,635	3,660
Current maturities of long-term debt	—	(250)
Short-term borrowings	(385)	(187)
Long-term debt	$ 3,250	$ 3,223

(a) In July 2009, $200 million of debt was swapped to a floating interest rate obligation. These swaps matured in February 2011.

(b) In December 2008, the swaps associated with this debt were terminated. The remaining long-term fair value of approximately $36 million related to the swaps is being amortized as a reduction to interest expense through the maturity date of the debt.

(c) $425 million of debt has been swapped to a fixed interest rate obligation with effective fixed interest rates ranging from 2.94% to 5.19%, for a net effective interest rate of 4.61% on the $426 million of outstanding debt under the DCP Partners' revolving credit facility as of March 31, 2011.

DCP Midstream's Debt Securities — In March 2010, we issued $600 million principal amount of 5.35% Senior Notes due 2020, or the 5.35% Notes, for proceeds of approximately $597 million, net of unamortized discounts and related offering costs. The 5.35% Notes mature and become due and payable on March 15, 2020. We pay interest semiannually on March 15 and September 15 of each year, and our first payment was on September 15, 2010. The net proceeds from this offering were used to repay a portion of our $800 million 7.875% Notes that were due August 2010, and for general corporate purposes.

The debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. The debt securities are unsecured and are redeemable at a premium at our option.

DCP Midstream's Credit Facilities with Financial Institutions — On March 18, 2011, we entered into an $800 million revolving credit facility, or the $800 Million Facility, which matures in March 2015, and terminated our existing $350 million revolving credit facility which was entered into in January 2010, and would have matured in April 2012. The $800 Million Facility allows for extensions of the March 2015 maturity date for two additional one year periods, with lender consent. The total amount of the $800 Million Facility may also be increased by an additional $450 million to $1,250 million with lender consent. There were no borrowings outstanding under the $800 Million Facility as of March 31, 2011.

We have a $450 million revolving credit facility, or the $450 Million Facility, which matures in April 2012. Any outstanding borrowings under the $450 Million Facility at maturity may, at our option, be converted into an unsecured one-year term loan. There were no borrowings outstanding under the $450 Million Facility as of March 31, 2011 and December 31, 2010.

The $800 Million Facility and the $450 Million Facility, or together, the Facilities, provide us with total revolving credit availability of $1,250 million. The $1,250 million of revolving credit from the Facilities may be used to support our commercial paper program, and for working capital requirements and other general corporate purposes as well as for letters of credit. As of March 31, 2011 and December 31, 2010, we had $385 million and $187 million of commercial paper outstanding, respectively, backed by the Facilities. As of both March 31, 2011 and December 31, 2010, we had $6 million in letters of credit outstanding. As of March 31, 2011, the available capacity under the Facilities was $859 million.

The $450 Million Facility bears interest at either: (1) the higher of Wells Fargo's prime rate or the Federal Funds rate plus 0.50% or (2) LIBOR plus an applicable margin, which is 0.31% based on our current credit rating. The facility incurs an annual fee of 0.09% based on our current credit rating. This fee is paid on drawn and undrawn portions of the facility.

The $800 Million Facility bears interest at either: (1) the higher of JP Morgan's prime rate or the Federal Funds rate plus 0.50% or (2) LIBOR plus an applicable margin, which is 1.50% based on our credit rating. The facility incurs an annual fee of 0.25% based on our current credit rating. This fee is paid on drawn and undrawn portions of the facility.

The Facilities require us to maintain a consolidated leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA, in each case as is defined by the Facilities) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated), following the consummation of qualifying asset acquisitions as defined by the Facilities, in the midstream energy business of not more than 5.5 to 1.0.

DCP Partners' Debt Securities — On September 30, 2010, DCP Partners issued $250 million of 3.25% Senior Notes due October 1, 2015. DCP Partners received proceeds of $248 million, which are net of underwriters' fees, related expenses and unamortized discounts, which were used to repay funds borrowed under the revolver portion of the DCP Partners' Credit Facility. Interest on the notes will be paid semiannually on April 1 and October 1 of each year, commencing April 1, 2011. The notes will mature on October 1, 2015, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in the condensed consolidated balance sheets and will be amortized over the term of the notes. The notes are senior unsecured obligations, ranking equally in right of payment with DCP Partners' existing unsecured indebtedness, including indebtedness under the DCP Partners' Credit Facility. DCP Partners is not required to make mandatory redemption or sinking fund payments with respect to these notes. The notes are redeemable at a premium at DCP Partners' option.

DCP Partners' Credit Facilities with Financial Institutions — DCP Partners has an $850 million revolving credit facility that matures on June 21, 2012, or the DCP Partners' Credit Agreement.

At March 31, 2011 and December 31, 2010, DCP Partners had less than $1 million and $32 million, respectively, of letters of credit outstanding under the DCP Partners' Credit Agreement. As of March 31, 2011, the unused capacity under the revolving credit facility was $424 million.

DCP Partners' borrowing capacity is limited at March 31, 2011 by the DCP Partners' Credit Agreement's financial covenant requirements. Except in the case of a default, amounts borrowed under DCP Partners' credit facility will not mature prior to the June 21, 2012 maturity date.

Under DCP Partners' Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wells Fargo Bank's prime rate or the Federal Funds rate plus 0.50% or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon DCP Partners' current credit rating. The DCP Partners' revolving credit facility incurs an annual facility fee of 0.07% to 0.175% dependent upon DCP Partners' credit rating. This fee is paid on drawn and undrawn portions of DCP Partners' revolving credit facility.

The DCP Partners' Credit Agreement requires DCP Partners to maintain a leverage ratio (the ratio of its consolidated indebtedness to its consolidated EBITDA, in each case as is defined by the DCP Partners' Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.5 to 1.0.

Other Agreements — As of March 31, 2011, DCP Partners had a contingent letter of credit facility for up to $10 million, on which DCP Partners pays a fee of 0.50% per annum. As of March 31, 2011, DCP Partners had no letters of credit issued under this facility. Any letters of credit issued on this facility will incur a net fee of 1.75% per annum and will not reduce the available capacity under the DCP Partners' Credit Agreement.

Other Financing — In March 2011, DCP Partners issued 3,596,636 common units at $40.55 per unit. DCP Partners received proceeds of $140 million, net of offering costs.

In November 2010, DCP Partners issued 2,875,000 common units at $34.96 per unit. DCP Partners received proceeds of $96 million, net of offering costs.

In August 2010, DCP Partners issued 2,990,000 common units at $32.57 per unit. DCP Partners received proceeds of $93 million, net of offering costs.

10. 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 by using physical and financial derivative instruments. All of our commodity derivative activities are conducted under the governance of internal Risk Management Committees that establish policies, limiting exposure to market risk and requiring daily reporting to management of potential financial exposure. These policies include statistical risk tolerance limits using historical price movements to calculate daily value at risk. The following briefly 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 asset based trading and marketing activities engage in the business of trading energy related products and services, including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and we 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. We manage commodity price risk related to owned and leased natural gas storage and pipeline assets by engaging in natural gas asset based trading and marketing. The commercial activities related to our natural gas asset based trading and marketing primarily consist of time spreads and basis spreads.

We may execute a time spread transaction when the difference between the current price of natural gas (cash or futures) and the futures market price for natural gas exceeds our cost of storing physical gas in our owned and/or leased storage facilities. The time spread transaction allows us to lock in a margin when this market condition exists. A time spread transaction is executed by establishing a long gas position at one point in time and establishing a corresponding short gas position at a different point in time. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period condensed consolidated statement of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our condensed consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

We may execute basis spread transactions when the market price differential between locations on a pipeline asset exceeds our cost of transporting physical gas through our owned and/or leased pipeline asset. When this market condition exists, we may execute derivative instruments around this differential at the market price. This basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period condensed consolidated statements of operations. As discussed above, the accounting for physical gas purchases and sales and the accounting for the derivative instruments used to manage such purchases and sales differ, and may subject our earnings to market volatility, even though the transaction represents an economic hedge in which we have locked in a future margin.

NGL Proprietary Trading

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

Commodity Cash Flow Protection Activities at DCP Partners

As a result of DCP Partners' operations of gathering, processing and transporting natural gas, DCP Partners takes title to a portion of residue gas, NGLs and condensate, which are considered to be DCP Partners' equity volumes. The possession of and the related operations of transporting and marketing of NGLs, creates commodity price risk due to market changes in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. DCP Partners has mitigated a portion of its expected commodity cash flow risk associated with these equity volumes through 2016 with natural gas, NGL and crude oil derivatives. Additionally, given the limited depth of the NGL derivatives market, DCP Partners utilizes crude oil swaps and costless collars and NGL swaps to mitigate a portion of its commodity price risk exposure for NGLs. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, DCP Partners experiences additional exposure as a result of the relationship where DCP Partners utilizes crude oil swaps to mitigate NGL price exposure. For shorter dated time periods where the NGL markets have greater liquidity, DCP Partners has utilized NGL swaps to mitigate a portion of its NGL price risk through December 2011 by entering into incremental NGL financial positions and by exchanging crude oil swaps for NGL swaps. These transactions are primarily accomplished through the use of swaps that exchange DCP Partners' floating price risk for a fixed price, but the type of instrument that is used to mitigate risk may vary depending upon DCP Partners' risk 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 condensed consolidated statements of operations.

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 hedge interest rate risk associated with our 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 based on historical rates.

DCP Partners mitigates a portion of its interest rate risk with interest rate swaps that reduce DCP Partners' exposure to market fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under the DCP Partners' revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations.

At March 31, 2011, DCP Partners had interest rate swap agreements totaling $450 million, of which DCP Partners has designated $425 million as cash flow hedges and accounts for the remaining $25 million under the mark-to-market method of accounting. As DCP Partners generally expects to have variable rate debt levels equal to or exceeding their swap positions during their term, the entire $450 million of these agreements generally mitigate DCP Partners' interest rate risk through June 2012, with $150 million extending from June 2012 through June 2014.

DCP Partners' has designated $425 million of interest rate swap agreements as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in Accumulated Other Comprehensive Income (Loss), or AOCI, in the condensed consolidated balance sheets and are reclassified into earnings as the hedged transactions impact earnings. However, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings during the period they are identified.

As of March 31, 2011, $275 million of the agreements reprice prospectively approximately every 90 days and the remaining $175 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, DCP Partners pays fixed rates ranging from 2.94% to 5.19%, and receives interest payments based on the three-month and one-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense.

We previously had interest rate cash flow hedges in place that were terminated in 2000. As a result, the remaining net loss deferred in AOCI relative to these cash flow hedges will be reclassified to interest expense through the remaining term of the debt through 2030, as the underlying transactions impact earnings.

Credit Risk

Our principal customers range from large, natural gas marketing services to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 40% of our NGL production is committed to ConocoPhillips and CP Chem, both related parties, under an existing 15-year contract, the primary production commitment of which expires in 2015. 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 Swap Dealers Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- In the event that we were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties 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.

- Additionally, if DCP Partners were to have an effective event of default under the DCP Partners' Credit Agreement that occurs and is continuing, DCP Partners' ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability 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 March 31, 2011, we had $106 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 March 31, 2011, if a credit-risk related event were to occur, we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of March 31, 2011, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $96 million.

As of March 31, 2011, DCP Partners' interest rate swaps were in a net liability position of $23 million of which, the entire amount is subject to credit-risk related contingent features. If DCP Partners were to have an event of default relative to any covenants of its credit agreement, that occurs and is continuing, the counterparties to DCP Partners' swap instruments have the right to request early termination and net settlement of the outstanding derivative position.

Collateral

As of March 31, 2011, we held cash of $2 million, included in other current liabilities in the condensed consolidated balance sheet related to cash postings by third parties, and letters of credit of $77 million from counterparties to secure their future performance under financial or physical contracts. We had cash deposits with counterparties of $25 million included in other current assets as of March 31, 2011, to secure our obligations to provide future services or to perform financial contracts. As of March 31, 2011, DCP Partners had a contingent letter of credit facility for up to $10 million, on which DCP Partners had no letters of credit issued and outstanding. This contingent letter of credit facility was issued directly by a financial institution and does not reduce the available capacity under the DCP Partners' Credit Agreement. As of March 31, 2011, DCP Partners had no other cash collateral posted with counterparties to its commodity derivative instruments. As of March 31, 2011, we had issued and outstanding parental guarantees totaling $85 million in favor of certain counterparties to DCP Partners' commodity derivative instruments to mitigate a portion of DCP Partners' collateral requirements with those counterparties. DCP Partners pays us a fee of 0.50% per annum on these guarantees. These parental guarantees and the contingent letter of credit facility reduce the amount of cash DCP Partners may be required to post as collateral. 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 publicly disclose 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.

Summarized Derivative Information

The following summarizes the balance within AOCI, net of noncontrolling interest, relative to our commodity and interest rate cash flow hedges:

	March 31, 2011	December 31, 2010
	(millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (3)	$ (3)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(9)	(10)
Total AOCI	$ (12)	$ (13)

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 condensed consolidated balance sheets, by major category, is summarized as follows:

Balance Sheet Line Item	March 31, 2011	December 31, 2010	Balance Sheet Line Item	March 31, 2011	December 31, 2010
	(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	$ (16)	$ (12)
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	(6)	(5)
	$ —	$ 1		$ (22)	$ (17)
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	$ (1)	$ (5)
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	(5)
	$ —	$ —		$ (1)	$ (10)
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments — current	$ 214	$ 143	Unrealized losses on derivative instruments — current	$ (246)	$ (163)
Unrealized gains on derivative instruments — long-term	49	25	Unrealized losses on derivative instruments — long-term	(95)	(55)
	$ 263	$ 168		$ (341)	$ (218)

The following table summarizes the impact on our condensed consolidated statement of operations of our derivative instruments that are accounted for using the fair value hedge method of accounting. Gains or losses recognized in earnings for each period are included in interest expense.

Derivatives in Fair Value Hedging Relationships	Amount of Gain Recognized in Earnings Three Months Ended March 31, 2011	2010
	(millions)	
Interest rate derivatives	$ —	$ 1

The following table summarizes the impact on our condensed consolidated balance sheets and condensed consolidated statements of operations of our derivative instruments, net of noncontrolling interest, that are accounted for using the cash flow hedge method of accounting:

	Loss Recognized in AOCI on Derivatives – Effective Portion		Loss Reclassified from AOCI to Earnings – Effective Portion			Gain (Loss) Recognized in Income on Derivatives – Ineffective Portion and Amount Excluded from Effectiveness Testing			Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	Three Months Ended March 31,								
	2011	2010	2011	2010		2011	2010		
	(millions)								
Interest rate derivatives	$ (1)	$ (3)	$ (2)	$ (3)	(a)	$ —	$ —	(a)(b)	$ (6)

(a) Included in interest expense in our condensed consolidated statements of operations.
(b) For the three months ended March 31, 2011 and 2010, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

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 condensed consolidated statements of operations. The following summarizes these amounts and the location within the condensed consolidated statements of operations that such amounts are reflected:

Commodity Derivatives: Statement of Operations Line Item	Three Months Ended March 31, 2011	2010
	(millions)	
Realized (losses) gains	$ (1)	$ 12
Unrealized (losses) gains	(28)	8
Trading and marketing (losses) gains, net	$ (29)	$ 20

We do not have any derivative financial instruments that qualify as a hedge of a net investment.

The following tables represent, by commodity type, our net long or short positions, 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.

	March 31, 2011								
	Crude Oil		Natural Gas		Natural Gas Liquids			Natural Gas Basis Swaps	
Year of Expiration	Net Long (Short) Position (Bbls)	Number of Contracts	Net Long (Short) Position (MMBtu)	Number of Contracts	Net Long (Short) Position (Bbls)	Number of Contracts		Net Long (Short) Position (MMBtu)	Number of Contracts
2011	(493,505)	661	(8,794,950)	370	(10,702,251)	472	(a)	(3,985,000)	143
2012	(1,003,762)	217	(7,966,000)	66	(8,281,900)	24	(b)	5,465,000	32
2013	(695,365)	77	(165,000)	5	(8,945,250)	3	(c)	1,825,000	1
2014	(547,500)	5	(365,000)	3	(9,000,000)	2	(c)	—	—
2015	(365,000)	2	—	—	—	—		—	—
2016	(183,000)	1	—	—	—	—		—	—

(a) Includes 18 physical index based derivative contracts totaling (9,459,000) Bbls
(b) Includes 4 physical index based derivative contracts totaling (9,195,000) Bbls
(c) Includes 2 physical index based derivative contracts totaling (9,000,000) Bbls

	March 31, 2010								
	Crude Oil		Natural Gas		Natural Gas Liquids			Natural Gas Basis Swaps	
Year of Expiration	Net Long (Short) Position (Bbls)	Number of Contracts	Net Long (Short) Position (MMBtu)	Number of Contracts	Net Long (Short) Position (Bbls)	Number of Contracts		Net Long (Short) Position (MMBtu)	Number of Contracts
2010	(1,661,375)	581	(12,997,500)	321	(7,811,963)	473	(a)	(20,792,500)	201
2011	(1,187,000)	113	(3,476,500)	99	(7,077,952)	67	(b)	6,840,000	76
2012	(265,750)	43	345,400	64	(9,000,000)	2	(c)	1,909,000	5
2013	(748,250)	4	(165,000)	3	(9,000,000)	2	(c)	(365,000)	1
2014	(365,000)	3	—	—	(9,000,000)	2	(c)	—	—

(a) Includes 18 physical index based derivative contracts totaling (8,520,000) Bbls
(b) Includes 3 physical index based derivative contracts totaling (9,165,000) Bbls
(c) Includes 2 physical index based derivative contracts totaling (9,000,000) Bbls

As of March 31, 2011, DCP Partners had interest rate swaps outstanding with individual notional values between $25 million and $80 million, which, in aggregate, exchange up to $450 million of DCP Partners’ floating rate obligation for a fixed rate obligation through June 2012, with $150 million extending from June 2012 through June 2014.

11. 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.

On December 30, 2010, DCP Partners acquired all of the interests in Marysville, an entity that owned a taxable C-Corporation consolidated return group. We estimated $35 million of deferred tax liabilities resulting from built-in tax gains recognized in the transaction and recorded this in our preliminary purchase price allocation as of December 31, 2010. On January 4, 2011, DCP Partners merged two wholly-owned subsidiaries of Marysville and converted the combined entity’s organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggered the deferred tax liabilities resulting from built-in tax gains to become currently payable. Accordingly, the estimated $35 million of deferred tax liabilities at December 31, 2010 have been included in accrued taxes in our condensed consolidated balance sheet as of March 31, 2011.

12. 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 condensed consolidated results of operations, financial position or cash flows.

General Insurance — Our insurance coverage is carried with an affiliate of ConocoPhillips, 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) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste storage, management, transportation and disposal, and other environmental matters including recently adopted U.S Environmental Protection Agency regulations related to reporting of greenhouse gas emissions which became effective in January 2010. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, the issuance of injunctions or restrictions on operations. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our condensed consolidated results of operations, financial position or cash flows.

We make expenditures in connection with environmental matters as part of our normal operations. Environmental liabilities as of March 31, 2011 and December 31, 2010, included in the condensed consolidated balance sheets as other current liabilities amounted to approximately $7 million and $6 million, respectively, and environmental liabilities included in the condensed consolidated balance sheets as other long-term liabilities amounted to $8 million and $9 million, respectively.

13. Supplemental Cash Flow Information

	Three Months Ended March 31,			
	2011		2010	
	(millions)			
Cash paid for interest, net of capitalized interest	$	72	$	89
Non-cash investing and financing activities:				
Distributions payable to members	$	35	$	98
Property, plant and equipment acquired with accounts payable	$	69	$	31
Other non-cash additions of property, plant and equipment	$	3	$	2
Acquisition related contingent consideration	$	—	$	1

During the three months ended March 31, 2011 and 2010, we received distributions from DCP Partners of $12 million and $11 million, respectively, which are eliminated in consolidation.

14. Subsequent Events

We have evaluated subsequent events occurring through May 10, 2011, the date the condensed consolidated financial statements were issued.

On May 9, 2011, we and Targa Resources Partners LP, or Targa, announced that we have entered into agreements which provide a long-term anchor commitment to the DCP Midstream Sandhills Pipeline LLC, or Sandhills Pipeline, and an interconnection of the Sandhills Pipeline to a new delivery point with Targa's Cedar Bayou Fractionators, LP, or CBF, facility at Mont Belvieu, Texas. We are in negotiations with several customers to sign long-term commitments to the Sandhills Pipeline. Additionally, we and Targa announced our entry into an agreement for a long-term anchor commitment by DCP for a new 100,000 barrels per day fractionation expansion at the Targa-operated and majority owned CBF facility; for which we will pay Targa a minimum annual payment of approximately $18 million for the first 10 years of the 15-year agreement, with the first payment being on the later of the first day of the month following start-up of the fractionator or August 1, 2013. If the commencement date does not occur by December 31, 2014, we have the right to terminate this agreement.

On April 25, 2011, the board of directors of DCP Partners' general partner declared a quarterly distribution of $0.625 per unit payable on May 13, 2011 to unitholders of record on May 6, 2011.

On April 18, 2011, DCP Partners made an estimated federal tax payment of $29 million related to their acquisition of Marysville.

In April 2011, our board of directors approved an $88 million dividend which was paid in April 2011.