DCPMidstream,LLC
ConsolidatedFinancialStatementsforthe
YearsEndedDecember31,2012,2011and2010

DCPMIDSTREAM,LLC
CONSOLIDATEDFINANCIALSTATEMENTS

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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, 2012 and 2011, 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, 2012, 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in accordance with accounting principles generally accepted in the United States of America.

Emphasis-of-Matter

The consolidated financial statements give retrospective effect to new disclosure requirements regarding information related to balance sheet offsetting of assets and liabilities as disclosed in Note 12 to the consolidated financial statements. Our opinion is not modified with respect to this matter.

/s/ Deloitte & Touche LLP

February 22, 2013 (May 13, 2013 as to Note 12)

DCPMIDSTREAM,LLC
CONSOLIDATEDBALANCESHEETS
(millions)

	December31, 2012	December31, 2011
ASSETS		
Currentassets:		
Cashandcashequivalents	$ 4	$ 9
Accountsreceivable:		
Customers,netofallowancefordoubtfulaccounts of$2millioneachperiod	886	981
Affiliates	172	307
Other	35	44
Inventories	105	105
Unrealizedgainsonderivativeinstruments	57	107
Other	30	24
Totalcurrentassets	1,289	1,577
Property,plantandequipment,net	7,331	6,448
Investmentsinunconsolidatedaffiliates	872	154
Intangibleassets,net	336	362
Goodwill	723	723
Unrealizedgainsonderivativeinstruments	10	23
Otherlong-termassets	223	125
Totalassets	$ 10,784	$ 9,412
LIABILITIESANDEQUITY		
Currentliabilities:		
Accountspayable:		
Trade	$ 1,065	$ 1,547
Affiliates	37	127
Other	51	49
Short-termborrowings	958	370
Distributionspayabletomembers	—	95
Currentmaturitiesoflong-termdebt	250	—
Unrealizedlossesonderivativeinstruments	65	113
Accruedtaxes	32	36
Capitalspendingaccrual	99	84
Other	218	226
Totalcurrentliabilities	2,775	2,647
Deferredincometaxes	92	93
Long-termdebt	4,443	3,820
Unrealizedlossesonderivativeinstruments	11	40
Otherlong-termliabilities	146	123
Totalliabilities	7,467	6,723
Commitmentsandcontingentliabilities		
Equity:		
Members'interest	2,413	2,164
Accumulatedothercomprehensiveloss	(9)	(12)
Totalmembers'equity	2,404	2,152
Noncontrollinginterest	913	537
Totalequity	3,317	2,689
Totalliabilitiesandequity	$ 10,784	$ 9,412

SeeNotestoConsolidatedFinancialStatements.

DCPMIDSTREAM,LLC
CONSOLIDATEDSTATEMENTSOFOPERATIONS
(millions)

	Year Ended December 31,		
	2012	**2011**	**2010**
Operatingrevenues:			
Salesofnaturalgasandpetroleumproducts	$ 7,826	$ 9,638	$ 8,163
Salesofnaturalgasandpetroleumproductstoaffiliates	1,886	2,874	2,414
Transportation,storageandprocessing	373	392	360
Tradingandmarketinggains,net	86	78	44
Totaloperatingrevenues	10,171	12,982	10,981
Operatingcostsandexpenses:			
Purchasesofnaturalgasandpetroleumproducts	7,662	9,400	8,208
Purchasesofnaturalgasandpetroleumproductsfromaffiliates	510	1,098	736
Operatingandmaintenance	667	626	551
Depreciationandamortization	291	449	413
Generalandadministrative	297	295	239
Stepacquisition—equityinterestre-measurement gain	—	—	(9)
Totaloperatingcostsandexpenses	9,427	11,868	10,138
Operatingincome	744	1,114	843
Earningsfromunconsolidatedaffiliates	34	26	34
Interestexpense,net	(193)	(213)	(253)
Incomebeforeincometaxes	585	927	624
Incometaxexpense	(2)	(3)	(5)
Netincome	583	924	619
Netincomeattributabletononcontrollinginterests	(97)	(61)	(27)
Netincomeattributabletomembers'interests	$ 486	$ 863	$ 592

SeeNotestoConsolidatedFinancialStatements.

DCPMIDSTREAM,LLC
CONSOLIDATEDSTATEMENTSOFCOMPREHENSIVEINCOME
(millions)

	YearEndedDecember31,		
	2012	**2011**	**2010**
Netincome	$ 583	$ 924	$ 619
Othercomprehensiveincome:			
Netunrealizedgains(losses)oncashflowhedges	1	(16)	(19)
Reclassificationofcashflowhedgesintoearnings	11	20	24
Totalothercomprehensiveincome	12	4	5
Totalcomprehensiveincome	595	928	624
Totalcomprehensiveincomeattributabletononcont rollinginterests	(106)	(64)	(28)
Totalcomprehensiveincomeattributabletomembers' interests	$ 489	$ 864	$ 596

SeeNotestoConsolidatedFinancialStatements.

DCPMIDSTREAM,LLC
CONSOLIDATEDSTATEMENTSOFCASHFLOWS
(millions)

	Year Ended December 31,		
	2012	**2011**	**2010**
Cashflowsfromoperatingactivities:			
Netincome	$ 583	$ 924	$ 619
Adjustmentstoreconcilenetincometonetcashprovidedbyoperatingactivities:			
Depreciationandamortization	291	449	413
Earningsfromunconsolidatedaffiliates	(34)	(26)	(34)
Distributionsfromunconsolidatedaffiliates	36	38	47
Stepacquisition—equityinterestre-measurement gain	—	—	(9)
Netunrealized(gains)lossesonderivativeinstruments	—	(47)	74
Deferredincometaxbenefit	(1)	(36)	(4)
Other,net	6	—	(4)
Changesinoperatingassetsandliabilitieswhich provided(used)cash:			
Accountsreceivable	241	(63)	(74)
Inventories	(9)	(1)	(5)
Accountspayable	(630)	474	69
Other	(139)	14	(97)
Netcashprovidedbyoperatingactivities	344	1,726	995
Cashflowsfrominvestingactivities:			
Capitalexpenditures	(2,285)	(1,113)	(538)
Acquisitions,netofcashacquired	(123)	(439)	(281)
Proceedsfromsaleoftwo-thirdsinterestinSand HillsandSouthernHills	919	—	—
Investmentsinunconsolidatedaffiliates	(240)	(6)	(2)
Proceedsfromsaleofassets	1	18	2
Purchasesofavailable-for-salesecurities	—	—	(623)
Proceedsfromsalesofavailable-for-salesecurities	—	—	633
Netcashusedininvestingactivities	(1,728)	(1,540)	(809)
Cashflowsfromfinancingactivities:			
Paymentofdividendsanddistributionstomembers	(405)	(789)	(575)
Proceedsfromdebt	2,915	2,024	1,468
Paymentofdebt	(2,042)	(1,675)	(1,636)
Proceedsfromissuanceofcommonunitsbyasubsidiary,netofofferingcosts	455	170	189
Proceedsfromcommercialpaper,net	588	183	187
Distributionspaidtononcontrollinginterests	(112)	(86)	(64)
Purchaseofadditionalinterestinasubsidiary	—	—	(4)
Deferredfinancingcosts	(20)	(12)	(7)
Netcashprovidedby(usedin)financingactivities	1,379	(185)	(442)
Netchangeincashandcashequivalents	(5)	1	(256)
Cashandcashequivalents,beginningofperiod	9	8	264
Cashandcashequivalents,endofperiod	$ 4	$ 9	$ 8

SeeNotestoConsolidatedFinancialStatements.

DCPMIDSTREAM,LLC
CONSOLIDATEDSTATEMENTSOFCHANGESINEQUITY
(millions)

	Members'Equity			
	Members' Interest	Accumulated Other Comprehensive (Loss)Income	Noncontrolling Interest	Total Equity
Balance,January1,2010	$ 2,020	$ (17)	$ 315	$ 2,318
Netincome	592	—	27	619
Othercomprehensiveincome	—	4	1	5
Dividendsanddistributions	(581)	—	(64)	(645)
Purchaseofadditionalinterestinasubsidiary	—	—	(5)	(5)
Issuanceofcommonunitsbyasubsidiary	42	—	147	189
Balance,December31,2010	2,073	(13)	421	2,481
Netincome	863	—	61	924
Othercomprehensiveincome	—	1	3	4
Dividendsanddistributions	(807)	—	(86)	(893)
Equity-basedcompensation	—	—	3	3
Issuanceofcommonunitsbyasubsidiary,netof offeringcosts	35	—	135	170
Balance,December31,2011	$ 2,164	$ (12)	$ 537	$ 2,689
Netincome	486	—	97	583
Othercomprehensiveincome	—	3	9	12
Dividendsanddistributions	(310)	—	(112)	(422)
Issuanceofcommonunitsbyasubsidiary,netof offeringcosts	73	—	382	455
Balance,December31,2012	$ 2,413	$ (9)	$ 913	$ 3,317

SeeNotestoConsolidatedFinancialStatements.

DCP MIDSTREAM, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years Ended December 31, 2012, 2011 and 2010

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 Phillips 66 and its affiliates, or Phillips 66. We operate in the midstream natural gas industry. Our primary operations consist of gathering, processing, compressing, treating, transporting and storing natural gas and fractionating, transporting, gathering, processing and storing 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 we act as general partner. As of December 31, 2012 and 2011, we owned an approximate 27% and 26% limited partner interest, respectively. Additionally, as of December 31, 2012 and 2011, we owned an approximate 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. Transactions between us and DCP Partners have been identified in the consolidated financial statements as transactions between affiliates.

Prior to May 1, 2012, we were owned 50% by ConocoPhillips. On May 1, 2012, ConocoPhillips created two independent publicly traded companies by separating its downstream businesses, including its 50% ownership interest in us, to a newly formed company, Phillips 66.

We are governed by a five member board of directors, consisting of two voting members from each of our owners and our 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 Spectra Energy and Phillips 66 (or ConocoPhillips prior to May 1, 2012) 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 Phillips 66.

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 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.

Certain amounts in the prior year's consolidated financial statements have been reclassified to the current year presentation.

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.

Allowance for Doubtful Accounts —Management estimates the amount of required allowances for the potential non-collectability of accounts receivable generally based upon 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 and processing and sales commitments, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

AccountingforRiskManagementandDerivativeActiv itiesandFinancialInstruments —Wedesignateeachenergy commodityderivativeaseithertradingornon-tradi ng.Certainnon-tradingderivativesarefurtherdes ignatedaseitherahedgeofa forecastedtransactionorfuturecashflow(cashfl owhedge),ahedgeofarecognizedasset,liability orfirmcommitment(fairvalue hedge),ornormalpurchasesornormalsalescontrac t.Theremainingnon-tradingderivatives,whichare relatedtoassetbased activitiesforwhichthehedgeaccountingortheno rmalpurchaseornormalsaleexceptionisnotelect ed,arerecordedatfairvaluein theconsolidatedbalancesheetsasunrealizedgains orunrealizedlossesonderivativeinstruments,wi thchangesinthefairvalue recognizedintheconsolidatedstatementsofoperat ions.Foreachderivative,theaccountingmethodan dpresentationofgainsand lossesorrevenueandexpenseintheconsolidateds tatementsofoperationsareasfollows:

ClassificationofContract	AccountingMethod	PresentationofGains&LossesorRevenue&Expense
TradingDerivatives	Mark-to-marketmethod(a)	Netbasisintradingandmarketinggainsandlosses
Non-TradingDerivatives:		
CashFlowHedge	Hedgemethod(b)	Grossbasisinthesameconsolidatedstatementsof operations categoryastherelatedhedgeditem
FairValueHedge	Hedgemethod(b)	Grossbasisin thesameconsolidatedstatementsofoperations categoryastherelatedhedgeditem
NormalPurchasesor NormalSales	Accrualmethod(c)	Grossbasisuponsettlementint hecorrespondingconsolidated statementsofoperationscategorybasedonpurchase orsale
Non-TradingDerivatives	Mark-to-marketmethod(a)	Netbasisintradingandmarketinggainsandlosses

(a) Mark-to-marketmethod—Anaccountingmethodwhereb ythechangeinthefairvalueoftheassetorliab ilityis recognizedintheconsolidatedstatementsofoperat ionsintradingandmarketinggainsandlossesduri ngthecurrent period.
(b) Hedgemethod—Anaccountingmethodwherebythecha ngeinthefairvalueoftheassetorliabilityis recordedin theconsolidatedbalancesheetsasunrealizedgains orunrealizedlossesonderivativeinstruments.Fo rcashflow hedges,thereisnorecognitionintheconsolidated statementsofoperationsfortheeffectiveportion untilthe serviceisprovidedortheassociateddeliveryperi odimpactsearnings.Forfairvaluehedges,thecha ngesinthefair valueoftheassetorliability,aswellastheoff settingchangesinvalueofthehedgeditem,arere cognizedinthe consolidatedstatementsofoperationsinthesamec ategoryastherelatedhedgeditem.
(c) Accrualmethod—Anaccountingmethodwherebythere isnorecognitionintheconsolidatedbalanceshee tsor consolidatedstatementsofoperationsforchangesi nfairvalueofacontractuntiltheserviceispro videdorthe associateddeliveryperiodimpactsearnings.

CashFlowandFairValueHedges —Forderivativesdesignatedasacashflowhedge orafairvaluehedge,wemaintainformal documentationofthehedge.Inaddition,weformall yassessbothattheinceptionofthehedgingrelat ionshipandonanongoingbasis, whetherthehedgecontractishighlyeffectiveino ffsettingchangesincashflowsorfairvaluesofh edgeditems.Allcomponentsof eachderivativegainorlossareincludedintheas sessmentofhedgeeffectiveness,unlessotherwisen oted.

Thefairvalueofaderivativedesignatedasacash flowhedgeisrecordedintheconsolidatedbalance sheetsasunrealizedgainsor unrealizedlossesonderivativeinstruments.Theef fectiveportionofthechangeinfairvalueofade rivativedesignatedasacashflow hedgeisrecordedintheconsolidatedbalancesheet sasAOCIandtheineffectiveportionisrecordedi ntheconsolidatedstatementsof operations.Duringtheperiodinwhichthehedgedt ransactionimpactsearnings,amountsinAOCIassoci atedwiththehedged transactionarereclassifiedtotheconsolidatedst atementsofoperationsinthesameaccountsasthe itembeinghedged.Hedge accountingisdiscontinuedprospectivelywhenitis determinedthatthederivativenolongerqualifies asaneffectivehedge,orwhenit isprobablethatthehedgedtransactionwillnotoc cur.Whenhedgeaccountingisdiscontinuedbecause thederivativenolonger qualifiesasaneffectivehedge,thederivativeis subjecttothemark-to-marketaccountingmethodpro spectively.Thederivative continuestobecarriedontheconsolidatedbalance sheetsatitsfairvalue;however,subsequentchan gesinitsfairvalueare recognizedincurrentperiodearnings.Gainsandlo ssesrelatedtodiscontinuedhedgesthatwereprevi ouslyaccumulatedinAOCIwill remaininAOCIuntilthehedgedtransactionimpacts earnings,unlessitisprobablethatthehedgedtr ansactionwillnotoccur,in whichcase,thegainsandlossesthatwereprevious lydeferredinAOCIwillbeimmediatelyrecognized incurrentperiodearnings.

Thefairvalueofaderivativedesignatedasafair valuehedgeisrecordedforbalancesheetpurposes asunrealizedgainsor unrealizedlossesonderivativeinstruments.Werec ognizethegainorlossonthederivativeinstrumen t,aswellastheoffsettinglossor gainonthehedgediteminearningsinthecurrent period.Allderivativesdesignatedandaccountedfo rasfairvaluehedgesare classifiedinthesamecategoryastheitembeingh edgedintheconsolidatedresultsofoperations.

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.

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 risk free interest rate and increases 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.

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 an other than temporary decline in value. When there is evidence of loss in value, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is considered to be permanently less than the carrying value 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.

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 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. For certain reporting units, we may elect to first assess qualitative factors to determine whether it is more likely than not that the fair value of our reporting units is less than the carrying value. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

Intangible assets consist 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.

Long-Lived Assets —We evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and

eventualdispositionoftheasset.Weconsidervari ousfactorswhendeterminingiftheseassetsshould beevaluatedforimpairment, includingbutnotlimitedto:

- asignificantadversechangeinlegalfactorsorbu sinessclimate;
- acurrentperiodoperatingorcashflowlosscombin edwithahistoryofoperatingorcashflowlosses, oraprojectionor forecastthatdemonstratescontinuinglossesassoci atedwiththeuseofalong-livedasset;
- anaccumulationofcostssignificantlyinexcessof theamountoriginallyexpectedfortheacquisition orconstructionofa long-livedasset;
- significantadversechangesintheextentormanner inwhichanassetisused,orinitsphysicalcond ition;
- asignificantadversechangeinthemarketvalueof anasset;or
- acurrentexpectationthat,morelikelythannot,a nassetwillbesoldorotherwisedisposedofbefor etheendofitsestimated usefullife.

Ifthecarryingvalueisnotrecoverable,theimpai rmentlossismeasuredastheexcessoftheasset's carryingvalueoveritsfair value.Weassessthefairvalueoflong-livedasset susingcommonlyacceptedtechniques,andmayusem orethanonemethod, including,butnotlimitedto,recentthirdpartyc omparablesalesanddiscountedcashflowmodels.Si gnificantchangesinmarket conditionsresultingfromeventssuchasthecondit ionofanassetorachangeinmanagement'sintent toutilizetheassetwould generallyrequiremanagementtoreassessthecashf lowsrelatedtothelong-livedassets.

UnamortizedDebtPremium,DiscountandExpense —Premiums,discountsandexpensesincurredwitht heissuanceoflong-termdebtareamortizedoverthetermofthedebtu singtheeffectiveinterestmethod.Thesepremiums anddiscountsarerecordedon theconsolidatedbalancesheetswithinlong-termde bt.Theseunamortizedexpensesarerecordedonthe consolidatedbalancesheetsas otherlong-termassets.

NoncontrollingInterest — Noncontrollinginterestrepresentstheownershipin terestsofthird-partyentitiesinthenetassetso f consolidatedaffiliates,includingownershipintere stofDCPPartners'publicunitholders,throughDCP Partners'publiclytraded commonunits,innetassetsofDCPPartnersandthe noncontrollinginterestwhichisrecordedinDCPP artners'consolidatedbalance sheets.Forfinancialreportingpurposes,theasset sandliabilitiesoftheseentitiesareconsolidate dwiththoseofourown,withany thirdpartyinterestinourconsolidatedbalancesh eetamountsshownasnoncontrollinginterestinequ ity.Distributionstoand contributionsfromnoncontrollinginterestsreprese ntcashpaymentstoandcashcontributionsfrom,re spectively,suchthird-party investors.

DividendsandDistributions — UnderthetermsoftheSecondAmendedandRestated LLCAgreementdatedJuly5,2005,as amended,ortheLLCAgreement,wearerequiredtom akequarterlydistributionstoSpectraEnergyandP hillips66(or ConocoPhillipspriortoMay1,2012)basedonalloc atedtaxableincome.TheLLCAgreementprovidesfor taxableincometobe allocatedinaccordancewithInternalRevenueCode Section704(c).ThisCodeSectionaccountsforthe variationbetweentheadjusted taxbasisandthefairmarketvalueofassetscontr ibutedtothejointventure.Thedistributionisba sedonthehighesttaxableincome allocatedtoeithermember,withtheothermemberr eceivingaproportionateamounttomaintaintheown ershipcapitalaccountsat 50%forbothSpectraEnergyandPhillips66.Taxdi stributionstothemembersarecalculatedbasedon estimatedannualtaxable incomeallocatedtothemembersaccordingtotheir respectiveownershippercentagesatthedatethedi stributionsbecamedue.Our boardofdirectorsdeterminestheamountoftheper iodicdividendstobepaidbyconsideringnetincom eattributabletomembers' interests,cashfloworanyothercriteriadeemeda ppropriate.TheLLCAgreementrestrictspaymentof dividendsexceptwiththe approvalofbothmembers.Dividendsareallocatedt othemembersinaccordancewiththeirrespectiveo wnershippercentages.

DCPPartnersconsidersthepaymentofaquarterlyd istributiontotheholdersofitscommonunits,to theextentDCPPartnershas sufficientcashfromitsoperationsafterestablish mentofcashreservesandpaymentoffeesandexpen ses,includingpaymentstoits generalpartner,awholly-ownedsubsidiaryofours. ThereisnoguaranteeK,however,thatDCPPartners willpaytheminimum quarterlydistributionontheunitsinanyquarter. DCPPartnerswillbeprohibitedfrommakinganydi stributionstounitholdersifit wouldcauseaneventofdefault,oraneventofdef aultexists,underitscreditagreement.

Revenue Recognition **—**We generate the majority of our revenues from natural gas gathering, processing, compressing, treating, transporting and storing and NGL fractionating, transporting, gathering, processing and storing, as well as trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas and NGLs, 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:

- *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, storing, or transporting of natural gas, and fractionating, storing and transporting NGLs. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase 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 fees we would otherwise charge for gathering of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes our revenues from these arrangements would be reduced.

- *Percent-of-proceeds/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 and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percent-of-proceeds/index arrangements relate directly with the price of natural gas and/or NGLs.

- *Keep-whole and wellhead purchase arrangements* —Under the terms of a keep-whole processing contract, we gather natural gas from the producer for processing, market the NGLs and return to the producer residue natural gas 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 the residue natural gas, or frac spread. We benefit in periods when NGL prices are higher relative to natural gas prices.

Our trading and marketing of natural gas and petroleum 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 or 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, 2012, 2011 and 2010.

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, 2012 and 2011 were imbalances totaling $35 million and $44 million, respectively. Included in the consolidated balance sheets as accounts payable—other, as of December 31, 2012 and 2011 were imbalances totaling $51 million and $49 million, respectively.

Significant Customers —Phillips 66 (or ConocoPhillips prior to May 1, 2012), a related party, was a significant customer in each of the past three years. See Note 4 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 equity-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. Awards granted to non-employees for acquiring, or in conjunction with selling, goods and services are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

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

Capitalized Interest —We capitalize interest during construction on 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.

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. Acquisitions

On July 3, 2012, DCP Partners acquired the Crossroads processing plant and associated gathering system, or the Crossroads System, from Penn Virginia Resource Partners, L.P. for $63 million. DCP Partners financed the acquisition with borrowings under its revolving credit facility. The Crossroads System, located in the southeastern portion of Harrison County in East Texas, includes approximately 8 miles of gas gathering pipeline, an 80 million cubic feet per day, or MMcf/d, cryogenic processing plant, approximately 20 miles of NGL pipeline and a 50% ownership interest in an approximately 11-mile residue gas pipeline, or CrossPoint Pipeline, LLC, which is accounted for as an unconsolidated affiliate using the equity method.

DCP Partners has accounted for the Crossroads System business combination using estimates of the fair value of assets acquired and liabilities assumed. The preliminary estimates of the fair value of identifiable assets acquired and liabilities assumed are subject to revisions, which may result in adjustments in the preliminary values as additional information relative to the fair value of assets and liabilities becomes available. The values assigned to the assets acquired and liabilities assumed may change in subsequent financial statements pending the final estimates of fair value. The following table summarizes the aggregate consideration and fair value of the identifiable assets acquired and liabilities assumed in the acquisition of Crossroads as of the acquisition date:

	July 3, 2012 (millions)
Aggregate consideration	$ 63
Accounts receivable	$ 4
Property, plant and equipment	63
Investments in unconsolidated affiliates	6
Other current liabilities	(4)
Other long-term liabilities	(6)
Total	$ 63

On April 12, 2012, DCP Partners announced that it has acquired a 10% ownership interest in the Texas Express Pipeline joint venture, from the operator, Enterprise Products Partners L.P., or Enterprise, representing an approximate investment of $85 million in the joint venture. In conjunction with the agreement, DCP Partners paid $11 million for its 10% ownership interest in the Texas Express Pipeline joint venture, representing DCP Partners' share of the investment through the closing date. DCP Partners will be responsible for spending approximately $75 million for its share of the remaining construction costs of the pipeline. Originating near Skellytown in Carson County, Texas, the 20-inch diameter Texas Express Pipeline will extend approximately 580 miles to Enterprise's NGL fractionation and storage complex in Mont Belvieu, Texas, and will provide access to other third-party facilities in the area. The Texas Express Pipeline will have an initial capacity of approximately 280,000 barrels per day, or Bbls/d. The Texas Express Pipeline has long-term, fee-based, ship-or-pay transportation commitments, including a commitment from us of 20,000 Bbls/d. Enterprise will construct and operate the pipeline, which is expected to be completed by the second quarter of 2013.

On April 12, 2012, we announced we have entered into an agreement with Enterprise and Anadarko Petroleum Corporation, or Anadarko, to design and construct a new NGL pipeline, or the Front Range Pipeline, that will originate in the Denver-Julesburg Basin, or the DJ Basin, in Colorado and extend approximately 435 miles to Skellytown, Texas. We, Enterprise and Anadarko each hold a 33.33% interest in the Front Range Pipeline. The Front Range Pipeline will connect to third-party systems and the Texas Express Pipeline, and will provide takeaway capacity and market access to the Gulf Coast markets. The Front Range Pipeline will have an initial capacity of approximately 150,000 Bbls/d. The Front Range Pipeline has long-term, fee-based, ship-or-pay transportation commitments, including a commitment from us of 40,000 Bbls/d, which will increase to 48,000 Bbls/d in 2019. Enterprise will construct and operate the pipeline, which is expected to be in service in the fourth quarter of 2013.

4.AgreementsandTransactionswithRelatedParties andAffiliates

DividendsandDistributions

DuringtheyearsendedDecember31,2012,2011and 2010,wepaidtaxdistributionsof$244million,$2 81millionand$275 million,respectively,basedonestimatedannualta xableincomeallocatedtoSpectraEnergyandPhilli ps66(orConocoPhillipsprior toMay1,2012)accordingtotheirrespectiveowner shippercentagesatthedatethedistributionsbeca medue.Duringtheyearsended December31,2012,2011and2010,wedeclaredandp aiddividendsof$161million,$508millionand$30 0million,respectively,to SpectraEnergyandPhillips66(orConocoPhillipsp riortoMay1,2012),allocatedinaccordancewith theirrespectiveownership percentages.

DuringtheyearsendedDecember31,2012,2011and 2010,DCPPartnerspaiddistributionsof$106milli on,$79millionand$57 million,respectively,toitspublicunitholders.

DCPSandHillsPipeline,LLCandDCPSouthernHills Pipeline,LLC

Duringthefourthquarterof2012,wecompletedthe saleofaone-thirdinterestinSandHillsPipelin e,LLC,orSandHills,and SouthernHillsPipeline,LLC,orSouthernHills,to bothSpectraEnergyandPhillips66,foraggregate considerationofapproximately $919million.Theproceedsfromthistransactionwe reusedtorepayborrowingsunderourtermloanand forgeneralcorporate purposes.Asaresultofthistransaction,we,Spec traEnergyandPhillips66eachownaone-thirdint erestinthetwopipelineprojects.

Phillips66andConocoPhillips

PriortoMay1,2012,wewereowned50%byConocoPh illips.OnMay1,2012,ConocoPhillipscreatedtwo independentpublicly tradedcompaniesbyseparatingitsdownstreambusin esses,includingits50%ownershipinterestinus, toanewlyformedcompany, Phillips66.Inconnectionwiththistransaction,o rthePhillips66separation,ConocoPhillipsisnot consideredarelatedpartyfor periodsafterMay1,2012.InconnectionwiththeP hillips66separation,asofMay1,2012,ChevronP hillipsChemical,orCPChem, isowned50percentbyPhillips66andwillcontinu etobeconsideredarelatedpartyforperiodsafte rMay1,2012.

Long-TermNGLPurchasesContractandTransactions —WesellaportionofourresiduegastoConocoPh illipsandsella portionofourNGLstoPhillips66andCPChem.In addition,wepurchasenaturalgasfromandprovide gathering,transportationand otherservicestoConocoPhillips.Approximately40% ofourNGLproductioniscommittedtoPhillips66 (orConocoPhillipspriorto May1,2012)andCPChemunderanexisting15-year contract,whichexpiresin2015.Shouldthecontrac tnotberenegotiatedor renewed,itprovidesforafiveyearratablewind-d ownperiodthrough2020.TheNGLcontractalsogran tsPhillips66(or ConocoPhillipspriortoMay1,2012)therighttop urchaseatindex-basedpricescertainquantitiesof NGLsproducedatprocessing plantsthatareacquiredand/orconstructedbyusi nthefutureinvariouscountiesintheMid-Contine ntandPermianBasinregions,and theAustinChalkarea.Weanticipatecontinuingto purchaseandsellcommoditieswithConocoPhillipsa sathird-partyandwith Phillips66andCPChemasrelatedparties,inthe ordinarycourseofbusiness.

Wearepartytoa15-yeargatheringandprocessing agreementwithConocoPhillips,whichexpiresinJan uary2026,whereby ConocoPhillipshasdedicatedallofitsnaturalgas productionwithinanareaofmutualinterestinOk lahomaandTexas.Thiscontract replacesandextendscertaincontractsthatweprev iouslyhadwithConocoPhillips,andisconsidereda third-partycontractforperiods afterMay1,2012.

SpectraEnergy

CommodityTransactions —WesellaportionofourresiduegasandNGLsto ,purchasenaturalgasandotherpetroleumproducts from,andprovidegathering,transportationandoth erservicestoSpectraEnergy.Managementanticipat escontinuingtopurchaseand sellcommoditiesandprovideservicestoSpectraEn ergyintheordinarycourseofbusiness.

DCPPartnershadpropanesupplyagreementswithSpe ctraEnergythatexpiredinApril2012,whichprovi dedDCPPartners propanesupplyatitsmarineterminalsforuptoap proximately185milliongallonsofpropaneannually .

DCPPartners

OnNovember2,2012,wecontributeda33.33%intere stinDCPSCTexasGP,ortheEagleFordSystem,an da$43millionfixed pricecommodityderivativeforathree-yearperiod toDCPPartners,foraggregateconsiderationof$43 8million,lesscustomary

working capital and other purchase price adjustments of $7 million. DCP Partners financed $344 million of the consideration with a two-year term loan agreement and $87 million was financed by the issuance at closing of an aggregate 1,912,663 of DCP Partners' common units to us. These transactions represent transactions between entities under common control. DCP Partners contributed an additional $17 million plus 33.33% of the working capital and construction work in progress for the Goliad Plant to the Eagle Ford System. The Goliad Plant will have gas processing capacity of 200 MMcf/d and it will become part of the existing Eagle Ford system. The Goliad Plant will be constructed and funded by DCP SC Texas GP, and will include the new Goliad Plant, a gathering system feeding the plant and ancillary support facilities including compression, liquids handling and residue pipeline interconnect facilities. In connection with this agreement, we also provided DCP Partners with a $7 million two-year direct commodity price hedge for its 33.33% interest in the Goliad Plant project. The Goliad Plant is expected to be completed in the first quarter of 2014.

On July 2, 2012, we contributed our minority ownership interests in two non-operated Mont Belvieu fractionators, or the Mont Belvieu Fractionators, to DCP Partners for aggregate consideration of $200 million, plus $5 million in working capital and other customary purchase price adjustments. DCP Partners entered into a two-year term loan agreement to finance $140 million of the aggregate purchase price. The remaining $60 million consideration was financed with the issuance by DCP Partners of 1,536,098 common units to us. The $140 million cash proceeds we received were used to pay down our short-term borrowings. The Mont Belvieu Fractionators consist of a 12.5 percent interest in the Enterprise Fractionator, which is operated by Enterprise, and a 20 percent interest in the Mont Belvieu I Fractionation Facility, which is operated by ONEOK Partners. We will continue to account for the Mont Belvieu Fractionators through our ownership interest in DCP Partners.

On March 30, 2012, we contributed our remaining 66.67% interest in Southeast Texas Holdings, GP, or Southeast Texas, and derivative instruments related to the Southeast Texas storage business, together the Southeast Texas Midstream Business, to DCP Partners, for consideration of $240 million, plus working capital and other customary purchase price adjustments of $21 million. $192 million of the consideration was financed with a portion of the proceeds from DCP Partners' 4.95% 10-year Senior Notes offering. The remaining $48 million consideration was financed with the issuance by DCP Partners of 1,000,417 common units to us. We also provided fixed NGL commodity derivatives for the three year period subsequent to closing valued at $40 million. Certain of the NGL commodity derivatives were valued at $25 million and represent consideration for the termination of a fee-based storage arrangement that we had with DCP Partners in conjunction with its initial 33.33% interest in Southeast Texas; the remaining portion of the commodity derivatives, valued at $15 million, mitigate a portion of DCP Partners' currently anticipated commodity price risk associated with the gathering and processing portion of the 66.67% interest in Southeast Texas acquired on March 30, 2012. The contribution of our remaining 66.67% interest in Southeast Texas represents a transaction between entities under common control. As a result of this transaction, DCP Partners owns 100% of the Southeast Texas Midstream Business, and we will continue to consolidate the Southeast Texas Midstream Business through our ownership interest in DCP Partners.

On January 3, 2012, we completed the previously announced contribution of our remaining 49.9% interest in DCP East Texas Holdings, LLC, or East Texas, to DCP Partners, for aggregate consideration of $165 million, less working capital and other purchase price adjustments of approximately $2 million, for a net purchase price of $163 million. DCP Partners financed approximately $130 million of the aggregate purchase price with borrowings under its term loan. The remaining $33 million consideration was financed with the issuance of 727,520 common units to us. As a result of this transaction, DCP Partners owns 100% of East Texas, and we will continue to consolidate East Texas through our ownership interest in DCP Partners.

Transactionswithotherunconsolidatedaffiliates

WesellaportionofourresiduegasandNGLsto,purchasenaturalgasandotherpetroleumproductsfrom,andprovidegathering andtransportationservicesto,unconsolidatedaffiliates.Weanticipatecontinuingtopurchaseandsellcommoditiesandprovide servicestounconsolidatedaffiliatesintheordinarycourseofbusiness.

Thefollowingtablesummarizesourtransactionswithrelatedpartiesandaffiliates:

	YearEndedDecember31,		
	2012	2011	2010
	(millions)		
Phillips66(a):			
Salesofnaturalgasandpetroleumproductstoaffiliates	$ 1,028	$ —	$ —
Purchasesofnaturalgasandpetroleumproductsfromaffiliates	$ 21	$ —	$ —
Operatingandgeneralandadministrativeexpenses	$ 3	$ —	$ —
ConocoPhillips(a):			
Salesofnaturalgasandpetroleumproductstoaffiliates	$ 800	$ 2,806	$ 2,365
Transportation,storageandprocessing	$ 5	$ 15	$ 18
Purchasesofnaturalgasandpetroleumproductsfromaffiliates	$ 192	$ 616	$ 435
Operatingandgeneralandadministrativeexpenses(b)	$ (1)	$ 4	$ 4
SpectraEnergy:			
Salesofnaturalgasandpetroleumproductstoaffiliates	$ —	$ 1	$ 1
Purchasesofnaturalgasandpetroleumproductsfromaffiliates (c)	$ 181	$ 343	$ 173
Operatingandgeneralandadministrativeexpenses	$ 12	$ 15	$ 6
Unconsolidatedaffiliates:			
Salesofnaturalgasandpetroleumproductstoaffiliates	$ 58	$ 67	$ 48
Transportation,storageandprocessing	$ 16	$ 17	$ 19
Purchasesofnaturalgasandpetroleumproductsfromaffiliates	$ 116	$ 139	$ 128

(a) InconnectionwiththePhillips66separation,ConocoPhillipsisnotconsideredarelatedpartyforperiods afterApril30,2012andPhillips66isconsideredarelatedpartyforperiodsstartingMay1,2012.
(b) TheyearendedDecember31,2012includeshurricaneinsurancerecoveryreceivables,whichweretreated asareductiontooperatingexpenseintheconsolidatedstatementsofoperations.
(c) Includesa$17millionpaymentreceivedinDecember2010,forreimbursementofdamagesweincurred whenaninternationalpropanesupplierbreacheditscontractwithSpectraEnergy.

Wehadbalanceswithrelatedpartiesandaffiliatesasfollows:

	December31,	
	2012	2011
	(millions)	
Phillips66(a):		
Accountsreceivable	$ 152	$ —
Accountspayable	$ (14)	$ —
Otherassets	$ 2	$ —
ConocoPhillips(a):		
Accountsreceivable	$ —	$ 283
Accountspayable	$ —	$ (73)
Otherassets	$ —	$ 2
SpectraEnergy:		
Accountspayable	$ (6)	$ (30)
Otherassets	$ 1	$ 1
Unconsolidatedaffiliates:		
Accountsreceivable	$ 20	$ 24
Accountspayable	$ (17)	$ (24)

(a) InconnectionwiththePhillips66 separation,ConocoPhillipsisnot consideredarelatedpartyforperiodsafterApril30,2012and Phillips66isconsideredarelatedpartyforperiodsstartingMay1, 2012.

5.Inventories

Inventorieswereasfollows:

	December31, 2012	December31, 2011
	(millions)	
Naturalgas	$ 23	$ 26
NGLs	82	79
Totalinventories	$ 105	$ 105

6.Property,PlantandEquipment

Property,plantandequipmentbyclassificationwereasfollows:

	Depreciable Life	December31, 2012	December31, 2011
		(millions)	
Gatheringa ndtransmissionsystems	20 - 50 years	$ 6,919	$ 6,069
Processing,storageandterminalfacilities	35 - 60 years	3,035	2,900
Other	3 - 30years	310	287
Constructionworkinprogress		1,494	1,366
Property,plantandequipment		11,758	10,622
Accumulateddepreciation		(4,427)	(4,174)
Property,plantandequipment,net		$ 7,331	$ 6,448

Interestcapitalizedonconstructionprojectsduringtheyearsended December31,2012,2011and2010 was$84million,$22 millionand$13million,respectively.AsofDecember31,2012,wehad$441millionofnon-cancelable purchaseobligationsfor capitalprojects.

Werevisedthedepreciablelivesforourgathering andtransmissionsystems,processing,storageandterminalfacilities,andother assets,effectiveApril1,2012.Thekeycontributingfactorstothechangeindepreciablelivesisan increaseintheestimatedremaining economicallyrecoverablereserves,resultingfromthedevelopmentoftechniquesthatimprovecommodity productionintheregions ourassetsserve.Advancesinextractionprocesses, alongwithimprovedtechnologyusedtolocatecommodityreserves,isgiving producersgreateraccesstounconventionalcommodities.Thenewremainingdepreciablelivesresultedinanapproximate$180 millionreductionindepreciationexpenseforthey earendedDecember31,2012.

Inconnectionwithourevaluationofdepreciablelives,wecorrectedtheclassificationforcertainassetswithinthepresentationof ourmajorclassesofproperty,plantandequipment asofDecember31,2011.

DepreciationexpensefortheyearsendedDecember31,2012,2011and2010was$265million,$423millionand$390million, respectively.

AssetRetirementObligations —AsofDecember31,2012and2011,wehad$91millionand$73million,respectively,ofasset retirementobligations,orAROs,inotherlong-term liabilitiesintheconsolidatedbalancesheets.Duringthefirstquarterof2012,we recordedachangeinestimatetoincreaseourAROs byapproximately$12million.Thechangeinestimatewasprimarilyattributable toareassessmentofanticipatedtimingofsettlementsandoftheoriginalAROestimatedamounts.For theyearsendedDecember31, 2012,2011and2010,accretionexpensewas$3million,lessthan$1millionand$5million,respectively.Accretionexpenseis recordedwithinoperatingandmaintenanceexpenseinourconsolidatedstatementsofoperations.

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

	December 31, 2012	December 31, 2011
	(millions)	
Balance, beginning of period	$ 73	$ 79
Accretion expense	3	—
Liabilities incurred	15	—
Liabilities settled	—	(6)
Balance, end of period	$ 91	$ 73

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

7. Goodwill and Intangible Assets

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

	December 31, 2012	December 31, 2011
	(millions)	
Beginning of period	$ 723	$ 721
Acquisitions	—	2
End of period	$ 723	$ 723

We performed our annual goodwill assessment at the reporting unit level. As a result of our assessment, we concluded that the entire amount of goodwill disclosed on the consolidated balance sheet is recoverable. We used a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

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

	December 31, 2012	December 31, 2011
	(millions)	
Gross carrying amount	$ 524	$ 524
Accumulated amortization	(188)	(162)
Intangible assets, net	$ 336	$ 362

For the years ended December 31, 2012, 2011 and 2010, we recorded amortization expense of $26 million, $26 million and $23 million, respectively. As of December 31, 2012, the remaining amortization periods ranged from less than 1 year to 23 years, with a weighted-average remaining period of approximately 18 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization
	(millions)
2013	$ 26
2014	20
2015	19
2016	19
2017	19
Thereafter	233
Total	$ 336

8. Investments in Unconsolidated Affiliates

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

	Percentage Ownership	December 31, 2012	December 31, 2011
		(millions)	
DCP Sand Hills Pipeline, LLC	33.33%	$ 263	$ —
DCP Southern Hills Pipeline, LLC	33.33%	253	—
Discovery Producer Services, LLC	40.00%	222	107
Texas Express Pipeline Joint Venture	10.00%	41	—
Main Pass Oil Gathering Company	66.67%	24	27
Front Range Pipeline Joint Venture	33.33%	24	—
Mont Belvieu Enterprise Fractionator	12.50%	18	—
Mont Belvieu I Fractionation Facility	20.00%	15	12
Other unconsolidated affiliates	Various	12	8
Total investments in unconsolidated affiliates		$ 872	$ 154

During the fourth quarter of 2012, we completed the sale of a one-third interest in Sand Hills Pipeline, LLC, or Sand Hills, and Southern Hills Pipeline, LLC, or Southern Hills, to both Spectra Energy and Phillips 66, for aggregate consideration of approximately $919 million. The proceeds from this transaction were used to repay borrowings under our term loan and for general corporate purposes. As a result of this transaction, we, Spectra Energy and Phillips 66 each own a one-third interest in the two pipeline projects. Prior to this transaction, we accounted for Sand Hills and Southern Hills as consolidated entities. Subsequent to this transaction, we account for Sand Hills and Southern Hills under the equity method of accounting. The Sand Hills and Southern Hills pipeline projects are currently under construction, and we will continue to operate the pipelines. Upon completion of the pipelines, our direct investment is expected to total between $700 million and $800 million.

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery Producer Services, LLC, or Discovery, of $30 million and $33 million at December 31, 2012 and 2011, 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 Main Pass Oil Gathering Company, or Main Pass, of $7 million and $8 million at December 31, 2012 and 2011, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Main Pass.

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 $5 million and $6 million at December 31, 2012 and 2011, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Mont Belvieu I.

Earningsfromunconsolidatedaffiliatesamountedtothefollowing:

	YearEndedDecember31,		
	2012	2011	2010
		(inmillions)	
DiscoveryProducerServices,LLC	$ 13	$ 22	$ 25
MainPassOilGatheringCompany	—	—	4
EnterpriseFractionator	12	—	—
MontBelvieuIFractionationFacility	9	6	5
Otherunconsolidatedaffiliates	—	(2)	—
Totalearningsfromunconsolidatedaffiliates	$ 34	$ 26	$ 34

Thefollowingtablessummarizethecombinedfinancialinformationofunconsolidatedaffiliates:

	YearEndedDecember31,		
	2012	2011	2010
		(millions)	
Incomestatement:			
Operatingrevenues	$ 431	$ 300	$ 302
Operatingexpenses	$ 254	$ 219	$ 222
Netincome	$ 175	$ 79	$ 78

	December31,	
	2012	2011
	(millions)	
Balancesheet:		
Currentassets	$ 165	$ 68
Long-termassets	3,037	499
Currentliabilities	(194)	(35)
Long-termliabilities	(67)	(51)
Netassets	$ 2,941	$ 481

9.FairValueMeasurement

DeterminationofFairValue

Belowisageneraldescriptionofourvaluationmethodologiesforderivativefinancialassetsandliabilities,whicharemeasuredat fairvalue.Fairvaluesaregenerallybaseduponquotedmarketpricesorpricesobtainedthroughexternalsources,whereavailable.If listedmarketpricesorquotesarenotavailable,wedeterminefairvaluebaseduponamarketquote,adjustedbyothermarket-basedor independentlysourcedmarketdatasuchashistoricalcommodityvolatilities,crudeoilfutureyieldcurves,and/orcounterpartyspecific considerations.Theseadjustmentsresultinafairvalueforeachassetorliabilityunderan“exitprice”methodology,inlinewithhow webelieveamarketplaceparticipantwouldvaluethatassetorliability.Fairvaluesareadjustedtoreflectthecreditriskinherentinthe transactionaswellasthepotentialimpactofliquidatingopenpositionsinanorderlymanneroverareasonabletimeperiodunder currentconditions.Theseadjustmentsmayincludeamountstoreflectcounterpartycreditquality,theeffectofourown creditworthiness,thetimevalueofmoneyand/ortheliquidityofthemarket.

- Counterpartycreditvaluationadjustmentsarenecessarywhenthemarketpriceofaninstrumentisnotindicativeofthefair valueasaresultofthecreditqualityofthecounterparty.Generally,marketquotesassumethatallcounterpartieshavenear zero,orlow,defaultratesandhaveequalcreditquality.Therefore,anadjustmentmaybenecessarytoreflectthecredit qualityofaspecificcounterpartytodeterminethefairvalueoftheinstrument.Werecordcounterpartycreditvaluation adjustmentsonallderivativesthatareinanetassetpositionasofthemeasurementdateinaccordancewithourestablished counterpartycreditpolicy,whichtakesintoaccountanycollateralmarginthatacounterpartymayhavepostedwithusas wellasanylettersofcreditthattheyhaveprovided.

- Entityvaluationadjustmentsarenecessarytoreflecttheeffectofourowncreditqualityonthefairvalueofournetliability positionwitheachcounterparty.Thisadjustmenttakesintoaccountanycreditenhancements,suchascollateralmarginwe mayhavepostedwithacounterparty,aswellasanylettersofcreditthatwehaveprovided.Themethodologytodetermine

thisadjustmentisconsistentwithhowweevaluate counterpartycreditrisk,takingintoaccountouro wncreditrating,current creditspreads,aswellasanychangeinsuchsprea dssincethelastmeasurementdate.

- Liquidityvaluationadjustmentsarenecessarywhen wearenotabletoobservearecentmarketpricefo rfinancialinstruments thattradeinlessactivemarketsforthefairvalu etoreflectthecostofexitingtheposition.Exch angetradedcontractsare valuedatmarketvaluewithoutmakinganyadditiona lvaluationadjustmentsand,therefore,noliquidit yreserveisapplied. Forcontractsotherthanexchangetradedinstrument s,wemarkourpositionstothemidpointofthebid /askspread,andrecord aliquidityreservebaseduponourtotalnetpositi on.Webelievethatsuchpracticeresultsinthemo streliablefairvalue measurementasviewedbyamarketparticipant.

Wemanageourderivativeinstrumentsonaportfolio basisandthevaluationadjustmentsdescribedabov earecalculatedonthis basis.Webelievethattheportfoliolevelapproach representsthehighestandbestusefortheseasse tsastherearebenefitsinherentin naturallyoffsettingpositionswithintheportfolio atanygiventime,andthisapproachisconsistent withhowamarketparticipant wouldviewandvaluetheassetsandliabilities.Al thoughwetakeaportfolioapproachtomanagingthe seassets/liabilities,inorderto reflectthefairvalueofanyoneindividualcontra ctwithintheportfolio,weallocateallvaluation adjustmentsdowntothecontract level,totheextentdeemednecessary,basedupone itherthenotionalcontractvolume,orthecontract value,whicheverismore applicable.

Themethodsdescribedabovemayproduceafairvalu ecalculationthatmaynotbeindicativeofnetrea lizablevalueorreflective offuturefairvalues.Whilewebelievethatourva luationmethodsareappropriateandconsistentwith othermarketparticipants,we recognizethattheuseofdifferentmethodologieso rassumptionstodeterminethefairvalueofcertai nfinancialinstrumentscould resultinadifferentestimateoffairvalueatthe reportingdate.Wereviewourfairvaluepolicies onaregularbasistakinginto considerationchangesinthemarketplaceand,ifne cessary,willadjustourpoliciesaccordingly.See Note11,RiskManagementand HedgingActivities,CreditRiskandFinancialInstr uments.

ValuationHierarchy

Ourfairvaluemeasurementsaregroupedintoathre e-levelvaluationhierarchy.Thevaluationhierarch yisbaseduponthe transparencyofinputstothevaluationofanasset orliabilityasofthemeasurementdate.Thethree levelsaredefinedasfollows:

- Level1—inputsareunadjustedquotedpricesfor *identical*assetsorliabilitiesinactivemarkets.

- Level2—inputsincludequotedpricesfor *similar*assetsandliabilitiesinactivemarkets,andinpu tsthatareobservablefor theassetorliability,eitherdirectlyorindirect ly,forsubstantiallythefulltermofthefinancia linstrument.

- Level3—inputsareunobservableandconsideredsi gnificanttothefairvaluemeasurement.

Afinancialinstrument'scategorizationwithinthe hierarchyisbaseduponthe inputthatrequiresthe highestdegreeofjudgment inthedeterminationoftheinstrument'sfairvalue .Followingisadescriptionofthevaluationmetho dologiesusedaswellasthe generalclassificationofsuchinstrumentspursuant tothehierarchy.

CommodityDerivativeAssetsandLiabilities

Weenterintoavarietyofderivativefinancialins truments,whichmayincludeexchangetradedinstrum ents(suchasNewYork MercantileExchange,orNYMEX,crudeoilornatural gasfutures)orover-the-counter,orOTC,instrume nts(suchasnaturalgas contracts,costlesscollars,crudeoilorNGLswaps).Theexchangetradedinstrumentsaregenerallyex ecutedontheNYMEX exchangewithahighlyratedbrokerdealerserving astheclearinghouseforindividualtransactions.

Ouractivitiesexposeustovaryingdegreesofcomm oditypricerisk.Tomitigateaportionofthisris k,andtomanagecommodity priceriskrelatedprimarilytoownednaturalgass torageandpipelineassets,weengageinnaturalga sassetbasedtradingand marketing,andwemayenterintonaturalgasandcr udeoilderivativestolockinaspecificmarginwh enmarketconditionsare favorable.Aportionofthismaybeaccomplishedth roughtheuseofexchangetradedderivativecontrac ts.Suchinstrumentsare generallyclassifiedasLevel1sincethevalueis equaltothequotedmarketpriceoftheexchangetr adedinstrumentasofourbalance sheetdate,andnoadjustmentsarerequired.Depend inguponmarketconditionsandourstrategywemay enterintoexchangetraded derivativepositionswithasignificanttimehorizo ntomaturity.Althoughsuchinstrumentsareexchan getraded,marketpricesmay onlybereadilyobservableforaportionofthedur ationoftheinstrument.Inordertocalculatethe fairvalueoftheseinstruments, readilyobservablemarketinformationisutilizedt otheextentitisavailable;however,intheevent thatreadilyobservablemarketdata

isnotavailable,wemayinterpolatebaseduponobservabledata.Ininstanceswhereweutilizeaninterpolatedvalue,anditis consideredsignificanttothevaluationofthecontractasawhole,wewouldclassifytheinstrumentwithinLevel2.Incertainlimited instances,wemayextrapolatebaseduponthelastreadilyobservabledata,developingourownexpectationoffairvalue.Totheextent thatwehaveutilizedextrapolateddata,anditis consideredsignificanttothevaluationofthecontractasawhole,wewouldclassify theinstrumentwithinLevel3.

Wealsoengageinthebusinessoftradingenergyrelatedproductsandservices,whichexposeustomarketvariablesand commoditypricerisk.Wemayenterintophysicalcontractsorfinancialinstrumentswiththeobjective ofrealizingapositivemargin fromthepurchaseandsaleofthesecommodity-based instruments.WemayenterintoderivativeinstrumentsforNGLsorotherenergy relatedproducts,primarilyusingtheOTCderivativeinstrumentmarkets,whicharenotasactiveandliquidasexchangetraded instruments.Marketquotesforsuchcontractsmayonlybeavailableforshortdatedpositions(uptosixmonths),andanactivemarket itselfmaynotexistbeyondsuchtimehorizon.Contractsenteredintowitharelativelyshorttimehorizonforwhichpricesarereadily observableintheOTCmarketaregenerallyclassifiedwithinLevel2.Contractswithalongertimehorizon,forwhichweinternally generateaforwardcurvetovaluesuchinstruments, aregenerallyclassifiedwithinLevel3.Theinternallygeneratedcurvemayutilize avarietyofassumptionsincluding,butnotlimited to,dataobtainedfromthird-partypricingservices,historicalandfutureexpected relationshipofNGLpricestocrudeoilprices,the knowledgeofexpectedsupplysourcescomingonline,expectedweathertrends withincertainregionsoftheUnitedStates,andthefutureexpecteddemandforNGLs.

Eachinstrumentisassignedtoalevelwithinthehierarchyattheendofeachfinancialquarterdependingupontheextenttowhich thevaluationinputsareobservable.Generally,an instrumentwillmovetowardalevelwithinthehierarchythatrequiresalower degreeofjudgmentasthetimetomaturityapproaches,andasthemarketsinwhichtheassettradeswilllikelybecomemoreliquidand pricesmorereadilyavailableinthemarket,thusreducingtheneedtorelyuponourinternallydevelopedassumptions.However,the levelofagiveninstrumentmaychange,ineitherdirection,dependinguponmarketconditionsandthe availabilityofmarket observabledata.

InterestRateDerivativeAssetsandLiabilities

DCPPartnersusesinterestrateswapagreementsas partofitsoverallcapitalstrategy.Theseinstrumentseffectivelyexchangea portionofDCPPartners'existingfloatingratedebttofixedratedebtandlockinratesonDCPPartners'anticipatedfuturefixed-rate debt.DCPPartners'swapsaregenerallypricedbaseduponaLondonInterbankOfferedRate,orLIBOR,instrumentwithsimilar duration,adjustedbythecreditspreadbetweenDCPPartnersandtheLIBORinstrument.Giventhataportionoftheswapvalueis derivedfromthecreditspread,whichmaybeobservedbycomparingsimilarassetsinthemarket,these instrumentsareclassified withinLevel2.Defaultriskoneithersideofthe swaptransactionisalsoconsideredinthevaluation.DCPPartnersrecords counterpartycreditandentityvaluationadjustmentsinthevaluationofitsinterestrateswaps;however,thesereservesarenot consideredtobeasignificantinputtotheoverall valuation.

Long-TermAssets

Weoffercertaineligibleexecutivestheopportunitytoparticipateinの DCPMidstreamLP'sNon-QualifiedExecutiveDeferred Compensationplan,andhaveelectedtofundaportionofthisparticipationbyinvestingincompanyownedlifeinsurancepolicies. Theseinvestmentsarereflectedwithinourconsolidatedbalancesheetsaslong-termassetsandareconsideredfinancialinstruments thatarerecordedatfairvalue,withanychangesinfairvaluebeingrecordedasagainorlossintheconsolidatedstatementsof operations.Giventhatthevalueoftheselifeinsurancepoliciesisdeterminedbaseduponcertainpubliclytradedmutualfundswhose valueisreadilyobservableinthemarketplace,theseinvestmentsareclassifiedwithinLevel2.

NonfinancialAssetsandLiabilities

Weutilizefairvalueonanon-recurringbasistoperformimpairmenttestsasrequiredonourproperty,plantandequipment, goodwillandintangibleassets.Assetsandliabilitiesacquiredinbusinesscombinationsarerecorded attheirfairvalueasofthedateof acquisition.Theinputsusedtodeterminesuchfair valueareprimarilybaseduponinternallydevelopedcashflowmodelsandwould generallybeclassifiedwithinLevel3,intheeventthatwewererequiredtomeasureandrecordsuch assetsatfairvaluewithinour consolidatedfinancialstatements.Additionally,we usefairvaluetodeterminetheinceptionvalueof ourassetretirementobligations. Theinputsusedtodeterminesuchfairvalueareprimarilybaseduponcostsincurredhistoricallyfor similarwork,aswellasestimates fromindependentthirdpartiesforcoststhatwould beincurredtorestoreleasedpropertytothecontractuallystipulatedcondition,and wouldgenerallybeclassifiedwithinLevel3.

We may 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 consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(millions)							
Current assets (a):								
Commodity derivatives	$ 18	$ 23	$ 16	$ 57	$ 29	$ 55	$ 23	$ 107
Long-term assets:								
Commodity derivatives (b)	$ 2	$ 5	$ 3	$ 10	$ 11	$ 7	$ 5	$ 23
Company owned life insurance (c)	$ —	$ 23	$ —	$ 23	$ —	$ 18	$ —	$ 18
Current liabilities (d):								
Commodity derivatives	$ (13)	$ (34)	$ (14)	$ (61)	$ (36)	$ (53)	$ (8)	$ (97)
Interest rate derivatives	$ —	$ (4)	$ —	$ (4)	$ —	$ (16)	$ —	$ (16)
Long-term liabilities (e):								
Commodity derivatives	$ (3)	$ (6)	$ —	$ (9)	$ (6)	$ (28)	$ (1)	$ (35)
Interest rate derivatives	$ —	$ (2)	$ —	$ (2)	$ —	$ (5)	$ —	$ (5)

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheets.
(b) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheets.
(c) Included in other long-term assets in our consolidated balance sheets.
(d) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.
(e) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheets.

Changes in Levels 1 and 2 Fair Value Measurements

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. We typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. These instruments are generally classified as Level 2. 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, 2012, 2011 and 2010, we had no transfers from Level 1 to Level 2 of the fair value hierarchy. During the years ended December 31, 2012, 2011 and 2010, we had the following transfers from Level 2 to Level 1 of the fair value hierarchy:

	Year Ended December 31,		
	2012	2011	2010
	(millions)		
Current assets	$ —	$ —	$ 1
Long-term assets	$ 1	$ 3	$ 3
Current liabilities	$ —	$ —	$ —
Long-term liabilities	$ —	$ (1)	$ (3)

These financial instruments have moved into a lower level 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. 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. 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, 2012(a):				
Beginning balance	$ 23	$ 5	$ (8)	$ (1)
Net realized and unrealized gains (losses) included in earnings(b)	3	(2)	(10)	1
Transfers into Level 3(c)	—	—	—	—
Transfers out of Level 3(c)	(1)	—	—	—
Settlements	(9)	—	4	—
Ending balance	$ 16	$ 3	$ (14)	$ —
Net unrealized gains (losses) still held included in earnings(b)	$ 17	$ (2)	$ (14)	$ —
Year ended December 31, 2011(a):				
Beginning balance	$ 50	$ 10	$ (45)	$ (1)
Net realized and unrealized gains (losses) included in earnings(b)	73	(5)	(56)	—
Transfers into Level 3(c)	—	—	—	—
Transfers out of Level 3(c)	—	—	—	—
Settlements	(100)	—	93	—
Ending balance	$ 23	$ 5	$ (8)	$ (1)
Net unrealized gains (losses) still held included in earnings(b)	$ 23	$ (5)	$ (8)	$ —

(a) There were no purchases, issuances and sales of derivatives for the years ended December 31, 2012 and 2011.
(b) Represents the amount of total gains or losses for the period, included in trading and marketing gains, net, 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 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	$ 18	$0.18–$2.18	Per gallon
Natural Gas	1	$3.51–$4.27	Per MMBtu (a)
Total assets	$ 19		
Liabilities:			
NGLs	$ (13)	$0.18–$2.13	Per gallon
Natural gas	(1)	$3.51–$4.27	Per MMBtu
Total liabilities	$ (14)		

(a) MMBtu represents one million British thermal units.

Estimated Fair Value of Financial Instruments

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

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

The fair value of our interest rate swaps and commodity non-trading derivatives is based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The "prices supported by quoted market prices and other external sources" category includes our interest rate swaps, our NGL and crude oil swaps, and our NYMEX positions in natural gas. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third-party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes "strip" transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate. The "prices based on models and other valuation methods" category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the 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. As of December 31, 2012, the carrying and fair value of our long-term debt, including current maturities of long-term debt, was $4,693 million and $5,236 million, respectively. As of December 31, 2011, the carrying and fair value of our long-term debt was $3,820 million and $4,264 million, respectively. We determine the fair value of our variable rate debt based upon

thediscountedpresentvalueofexpectedfuturecas hflows,takingintoaccountthedifferencebetween thecontractualborrowing spreadandthespreadforsimilarcreditfacilities availableinthemarketplace.Wedeterminethefai rvalueofourfixed-ratedebtbased onquotesobtainedfrombonddealers.Weclassifyt hefairvalueofouroutstandingdebtbalanceswith inLevel2ofthefairvalue hierarchy.

10.Financing

	December31, 2012	December31, 2011
	(millions)	
Short-termborrowings	$ 958	$ 370
DCPMidstream'sdebtsecurities:		
IssuedNovember2008,interestat9.700%payablese miannually,dueDecember2013	250	250
IssuedOctober2005,interestat5.375%payablesem iannually,dueOctober2015	200	200
IssuedFebruary2009,interestat9.750%pay ablesemiannually,dueMarch2019	450	450
IssuedMarch2010,interestat5.350%payablesemia nnually,dueMarch2020	600	600
IssuedSeptember2011,interestat4.750%payables emiannually,dueSeptember2021	500	500
IssuedAugust2000,in terestat8.125%payablesemiannually,dueAugust2 030(a)	300	300
IssuedOctober2006,interestat6.450%payablesem iannually,dueNovember2036	300	300
IssuedSeptember2007,interestat6.750%payables emiannually,dueSeptember2037	450	450
DCPPartners'debtsecurities:		
IssuedSeptember2010,interestat3.25%payablese miannually,dueOctober2015	250	250
IssuedNovember2012,interestat2.50%payablesem iannually,dueDecember2017	500	—
IssuedMarch2012,interest at4.95%payablesemiannually,dueApril2022	350	—
DCPPartners'revolvingcreditfacility,weighted -averagevariableinterestrateof 1.47% and1.69%,respectively,dueNovember2016(b)	525	497
Fairvalueadjustmentsrelatedtointerestrate swapfairvaluehedges(a)	32	34
Unamortizeddiscount	(14)	(11)
Totaldebt	5,651	4,190
Currentmaturitiesoflong -termdebt	(250)	—
Short-termborrowings	(958)	(370)
Totallong-termdebt	$ 4,443	$ 3,820

(a) InDecember2008,theswapsassociatedwiththisde btwereterminated.Theremaininglong-termfairva lueof approximately$32millionrelatedtotheswapsisb eingamortizedasareductiontointerestexpenset hroughthe maturitydateofthedebt.

(b) $150millionhasbeenswappedtoafixedinterestr ateobligationwitheffectivefixedinterestrates rangingfrom 2.94%to2.99%,foraneteffectiveinterestrateo f2.25%onthe$525millionofoutstandingdebtund erDCP Partners'revolvingcreditfacilityasofDecember 31,2012.$450millionofdebtwasswappedtoafix ed-rate obligationwitheffectiveinterestratesrangingfr om2.94%to5.19%,foraneteffectiverateof4.86 %onthe$497 millionofoutstandingdebtundertheDCPPartners' revolvingcreditfacilityasofDecember31,2011.

Approximatefuturematuritiesoflong-termdebtin theyearindicatedareasfollowsatDecember31,2 012:

	DebtMaturities (millions)
2013	$ 250
2014	—
2015	450
2016	525
2017	500
Thereafter	2,950
	4,675
Fairvalu eadjustmentsrelatedtointerestrateswapfair valuehedges	32
Unamortizeddiscount	(14)
Currentmaturitiesoflong -termdebt	(250)
Long-termdebt	$ 4,443

DCP Midstream's Debt Securities —In September 2011, we issued $500 million principal amount of 4.75% Senior Notes due September 30, 2021, or the 4.75% Notes, for proceeds of approximately $496 million, net of unamortized discounts and related offering costs. We will pay interest semiannually on March 30 and September 30 of each year, and our first payment occurred on March 30, 2012. 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. The net proceeds from this offering were used to repay short-term borrowings and for general corporate purposes.

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

DCP Midstream's Credit Facilities with Financial Institutions— On March 2, 2012, we entered into a $2 billion revolving credit facility, or the $2 Billion Facility, which matures in March 2017 and terminated our existing $1,250 million revolving credit facility which would have matured in March 2015 and our existing $450 million revolving credit facility which would have matured in April 2012, or together the $1.7 Billion Facilities. The $2 Billion Facility allows for up to two one-year extensions of the March 2017 maturity date, subject to lender consent. There were no borrowings outstanding under the $2 Billion Facility as of December 31, 2012.

The $2 Billion Facility may be used to support our commercial paper program, our capital expansion program, working capital requirements and other general corporate purposes as well as for letters of credit, up to a maximum of $200 million of outstanding letters of credit. As of December 31, 2012 and 2011, we had $958 million and $370 million of commercial paper outstanding, backed by the $2 Billion Facility and the $1.7 Billion Facilities, respectively, which are included in short-term borrowings in our consolidated balance sheets. As of December 31, 2012 and 2011, we had $6 million and $7 million, respectively, in letters of credit outstanding. As of December 31, 2012, the available capacity under the $2 Billion Facility was $1,036 million.

On March 2, 2012, we entered into a $1 billion delayed draw term loan agreement, or the Term Loan, which matures in September 2014. Proceeds from the Term Loan may be used for our capital expansion program and working capital requirements. On November 15, 2012, we repaid $250 million of outstanding borrowings under the Term Loan with proceeds from the sale of a one-third interest in Sand Hills and Southern Hills to both Spectra Energy and Phillips 66, as required by the Term Loan agreement. Under the Term Loan agreement, amounts repaid on the Term Loan may not be reborrowed, as such; the Term Loan capacity has been reduced to approximately $750 million as of December 31, 2012. As of December 31, 2012, there were no borrowings outstanding under the Term Loan.

As of December 31, 2012, the unused capacity under the $2 Billion Facility and Term Loan was $1,786 million, of which approximately $960 million was available for general working capital purposes. Our borrowing capacity is limited at December 31, 2012 by the $2 Billion Facility and Term Loan's financial covenant requirements.

The $2 Billion Facility bears interest at either: (1) LIBOR, plus an applicable margin of 1.175% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1% plus (b) an applicable margin of 0.175% based on our current credit rating. The $2 Billion Facility incurs an annual facility fee of 0.20% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $2 Billion Facility.

The Term Loan bears interest at either: (1) LIBOR, plus an applicable margin of 1.375% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Royal Bank of Canada's prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1% plus (b) an applicable margin of 0.375% based on our current credit rating. The Term Loan incurs an annual commitment fee of 0.20% based on our current credit rating. This fee is paid on undrawn portions of the Term Loan.

The $2 Billion Facility and the Term Loan 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. Any drawn amounts under the Term Loan are required to be repaid from proceeds from the sale or contribution of Sand Hills or Southern Hills. Commencing with the fiscal period ending December 31, 2012 and continuing through

the fiscal period ending December 31, 2013, the definition of consolidated EBITDA under the $2 Billion Facility and the Term Loan has been amended to allow for additional adjustments related to certain projects.

DCP Partners' Debt Securities —On November 27, 2012, DCP Partners issued $500 million of 2.50% 5-year Senior Notes, or the DCP Partners 2.50% Notes, due December 1, 2017. DCP Partners received net proceeds of $494 million, net of underwriters' fees, related expenses and unamortized discounts. Interest on the notes will be paid semiannually on June 1 and December 1 of each year, commencing June 1, 2013. 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.

On March 13, 2012, DCP Partners issued $350 million of 4.95% 10-year Senior Notes, or the DCP Partners 4.95% Notes, due April 1, 2022. DCP Partners received proceeds of $346 million, net of underwriters' fees, related expenses and unamortized discounts, which were used to fund the cash portion of DCP Partners' acquisition of our 66.67% remaining interest in Southeast Texas and to repay funds borrowed under DCP Partners' Credit Agreement and the DCP Partners Term Loan. Interest on the notes will be paid semiannually on April 1 and October 1 of each year, and DCP Partners' first payment occurred on October 1, 2012. 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.

In September 2010, DCP Partners issued $250 million of 3.25% Senior Notes, or the DCP Partners' 3.25% Notes, due October 1, 2015, for proceeds of approximately $248 million, which are net of unamortized discounts and related offering costs. The DCP Partners' 3.25% Notes mature and become due and payable on October 1, 2015, unless redeemed prior to maturity. DCP Partners' pays interest semiannually on April 1 and October 1 of each year, with the first payment made on April 1, 2011. The net proceeds from this offering were used to repay funds borrowed under the revolver portion of the DCP Partners' Credit Facility.

DCP Partners' debt securities mature and become payable on the respective due dates, unless redeemed prior to maturity, and are not subject to any sinking fund provisions. DCP Partners' debt securities are senior unsecured obligations, and are redeemable at a premium at DCP Partners' option.

DCP Partners' Credit Facilities with Financial Institutions —On November 2, 2012, DCP Partners entered into a 2-year term loan agreement, or the $344 Million Term Loan, and borrowed $344 million to fund the cash portion of the acquisition of a 33.33% interest in the Eagle Ford System. On July 2, 2012, DCP Partners entered into a 2-year term loan agreement, or the $140 Million Term Loan, and borrowed $140 million to fund the cash portion of its acquisition of the Mont Belvieu Fractionators. In November 2012, DCP Partners repaid both term loans with proceeds from the DCP Partners 2.50% Notes.

On January 3, 2012, DCP Partners entered into a 2-year term loan agreement and borrowed $135 million, which was used to fund a portion of DCP Partners' acquisition of our remaining 49.9% interest in East Texas. In March 2012, DCP Partners repaid this term loan with proceeds from the DCP Partners 4.95% Notes.

DCP Partners has a $1 billion revolving credit facility, or the DCP Partners' Credit Agreement, that matures November 10, 2016. As of both December 31, 2012 and 2011, DCP Partners had $1 million of letters of credit issued under the DCP Partners' Credit Agreement. As of December 31, 2012, the unused capacity under the revolving credit facility was $474 million, which was available for general working capital purposes. DCP Partners' borrowing capacity is limited at December 31, 2012 by DCP Partners' Credit Agreement's financial covenant requirements.

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

The DCP Partners' Credit Agreement requires DCP Partners to maintain a leverage ratio (the ratio of DCP Partners' consolidated indebtedness to DCP Partners' consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 5.0 to 1.0, and following the consummation of qualifying acquisitions (as defined by the DCP Partners' Credit Agreement), 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.

OtherAgreements —DCPPartnershadacontingentletterofcreditf acilityforupto$10million,whichexpiredinJul y2012.

OtherFinancing —DuringtheyearendedDecember31,2012,DCPPart nersissued1,147,654ofitscommonunits,underan on-goingequitydistributionagreementwithafinancia linstitutionandreceivedproceedsof$47million, netofcommissionsandoffering costs.

InJuly2012,DCPPartnersclosedaprivateplaceme ntofequitywithagroupofinstitutionalinvestor sinwhichDCPPartners sold4,989,802ofitscommonunitsatapriceof$3 5.55perunitandreceivedproceedsof$174million ,netofofferingcosts.

InMarch2012,DCPPartnersissued5,148,500ofits commonunitsat$47.42perunit.DCPPartnersrece ivedproceedsof$234 million,netofofferingcosts.

During2011,DCPPartnersissued761,285ofitscom monunits,underanon-goingequitydistributionag reementwithCitigroup GlobalMarketsInc.,andreceivedproceedsfromuni tsissuedof$30million,netofcommissionsandof feringcosts.

InMarch2011,DCPPartnersissued3,596,636common unitsat$40.55perunit.DCPPartnersreceivedpr oceedsof$140 million,netofofferingcosts.

InNovember2010,DCPPartnersissued2,875,000com monunitsat$34.96perunit.DCPPartnersreceived proceedsof$96 million,netofofferingcosts.

InAugust2010,DCPPartnersissued2,990,000commo nunitsat$32.57perunit.DCPPartnersreceivedp roceedsof$93million, netofofferingcosts.

11.RiskManagementandHedgingActivities,Credit RiskandFinancialInstruments

Ourday-to-dayoperationsexposeustoavarietyof risksincludingbutnotlimitedtochangesinthe pricesofcommoditiesthatwe buyorsell,changesininterestrates,andthecre ditworthinessofeachofourcounterparties.Weman agecertainoftheseexposuresby usingphysicalandfinancialderivativeinstruments .Allofourcommodityderivativeactivitiesareco nductedunderthegovernanceof internalRiskManagementCommitteesthatestablish policieslimitingexposuretomarketriskandrequi ringdailyreportingto managementofpotentialfinancialexposure.Thesep oliciesincludestatisticalrisktolerancelimitsu singhistoricalpricemovementsto calculatedailyvalueatrisk.Thefollowingbriefl ydescribeseachoftherisksthatwemanage.

CommodityPriceRisk

Ourportfolioofcommodityderivativeactivityisp rimarilyaccountedforusingthemark-to-marketmet hodofaccounting; however,dependinguponourriskprofileandobject ives,incertainlimitedcases,wemayexecutetran sactionsthatqualifyforthe hedgemethodofaccounting.Therisks,strategiesa ndinstrumentsusedtomitigatesuchrisks,aswell asthemethodofaccountingare discussedandsummarizedbelow.

NaturalGasAssetBasedTradingandMarketing

Ournaturalgasassetbasedtradingandmarketinga ctivitiesengageinthebusinessoftradingenergy relatedproductsand services,includingmanagingpurchaseandsalespor tfolios,storagecontractsandfacilities,andtran sportationcommitmentsfor products.Theseenergytradingoperationsareexpos edtomarketvariablesandcommoditypriceriskwit hrespecttotheseproducts andservices,andwemayenterintophysicalcontra ctsandfinancialinstrumentswiththeobjectiveof realizingapositivemarginfrom thepurchaseandsaleofcommodity-basedinstrument s.Wemanagecommoditypriceriskrelatedtoourna turalgasstorageand pipelineassetsbyengaginginnaturalgasassetba sedtradingandmarketing.Thecommercialactivitie srelatedtoournaturalgasasset basedtradingandmarketingprimarilyconsistofti mespreadsandbasisspreads.

Wemayexecuteatimespreadtransactionwhenthed ifferencebetweenthecurrentpriceofnaturalgas (cashorfutures)andthe futuresmarketpricefornaturalgasexceedsourco stofstoringphysicalgasinourownedand/orleas edstoragefacilities.Thetime spreadtransactionallowsustolockinamarginwh enthismarketconditionexists.Atimespreadtran sactionisexecutedby establishingalonggaspositionatonepointinti meandestablishinganequalshortgaspositionat adifferentpointintime.We typicallyuseswapstoexecutethesetransactions, whicharenotdesignatedashedginginstrumentsand arerecordedatfairvaluewith changesinfairvaluerecordedinthecurrentperio dconsolidatedstatementsofoperations.Whilegas heldinourstoragelocationsis recordedatthelowerofaveragecostormarket,th ederivativeinstrumentsthatareusedtomanageou rstoragefacilitiesarerecorded

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.

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 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.

In order for our storage facility to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. During 2011, we commenced an expansion project to build an additional storage cavern. Upon completion of the expansion project, we will be required to purchase a significant amount of base gas to bring the storage cavern to operation. To mitigate risk associated with the forecasted purchase of natural gas in June, July and August 2013, we executed a series of derivative financial instruments, which have been designated as cash flow hedges. These cash flow hedges were in a loss position of $3 million as of December 31, 2012, and will fluctuate in value through the term of construction. Any effective changes in fair value of these derivative instruments will be deferred in AOCI until the underlying purchase of inventory occurs. While the cash paid or received upon settlement of these hedges will economically offset the cash required to purchase the base gas, following completion of the additional storage cavern, any deferred gain or loss at the time of the purchase will remain in AOCI until the cavern is emptied and the base gas is sold. As of December 31, 2012, there was a deferred loss of $3 million recognized in AOCI in relation to our 2009 storage cavern expansion, and will remain in AOCI until such time that the cavern is emptied and the base gas is sold.

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 the natural gas asset based trading and marketing and NGL proprietary trading.

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 these commodities 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 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 depth of the NGL derivatives market, DCP Partners has used crude oil swaps and costless collars to mitigate a portion of its commodity price risk exposure for NGLs. Prices of NGLs have generally been related to the price of crude oil, however, there are some periods of time when NGL pricing may be at a greater discount to crude oil pricing, resulting in additional exposure to NGL commodity prices. During 2012, the relationship of NGLs to crude oil has been lower than historical relationships, however, a significant amount of DCP Partners' NGL hedges from 2012 through 2015 are direct product hedges. When crude oil swaps become short-term in nature, DCP Partners may periodically convert certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. These transactions are primarily accomplished through the use of forward contracts that exchange DCP Partners' floating price risk for a fixed price. DCP Partners also utilizes costless 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.

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 variable interest rates to fixed rates on our existing debt and to lock in rates on our anticipated future fixed-rate debt, respectively. 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.

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

At December 31, 2011, DCP Partners had interest rate swap agreements totaling $450 million, of which DCP Partners had designated $425 million as cash flow hedges and accounted for the remaining $25 million under the mark-to-market method of accounting. In March 2012, DCP Partners paid down a portion of the DCP Partners' Credit Agreement. As a result of the paydown of the DCP Partners' Credit Agreement, DCP Partners discontinued cash flow hedge accounting on $225 million of its interest rate swap agreements. $300 million of swap agreements settled in the second quarter of 2012.

At December 31, 2012, DCP Partners had interest rate swap agreements extending through June 2014 totaling $150 million, which DCP Partners has designated as cash flow hedges. At December 31, 2012, $150 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 2.99%, and receives interest payments based on the one-month LIBOR.

Effectiveness of DCP Partners' interest rate swap agreements designated as cash flow hedges 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 AOCI in the consolidated balance sheets and are reclassified into earnings as the hedged transactions impacted 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.

In March 2012, DCP Partners settled $195 million of its forward-starting interest rate swap agreements for $7 million. The remaining net deferred losses of $5 million in AOCI will be amortized into interest expense associated with DCP Partners' long-term debt through 2022.

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 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 Phillips 66 (or ConocoPhillips prior to May 1, 2012) and CPChem, 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 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 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, 2012, we had $23 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, 2012, 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, 2012, 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 $21 million.

As of December 31, 2012, DCP Partners had $150 million of individual interest rate swap instruments that were in a net liability position of $6 million and were subject to credit-risk related contingent features. If DCP Partners were to have an event of default relative to any covenants of the DCP Partners' Credit Agreement, that occurs and is continuing, the counterparties to DCP Partners' swap instruments have the right to request that DCP Partners net settle the instrument in the form of cash.

Collateral

As of December 31, 2012, we held cash of less than $1 million, included in other current liabilities in the consolidated balance sheet related to cash postings by third parties, and letters of credit of $72 million from counterparties to secure their future performance under financial or physical contracts. We had cash deposits with counterparties of $17 million included in other current assets as of December 31, 2012, to secure our obligations to provide future services or to perform under financial contracts. As of December 31, 2012, DCP Partners had no cash collateral posted with counterparties to its commodity derivative instruments. As of December 31, 2012, we had issued and outstanding parental guarantees totaling $25 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 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

suspenddeliveries,cancelagreementsorcontinued eliveriestothebuyerafterthebuyerprovidessec urityforpaymentsatisfactoryto theseller.

SummarizedDerivativeInformation

ThefollowingsummarizesthebalancewithinAOCI,n etofnoncontrollinginterest,relativetoourcomm odityandinterestrate cashflowhedges:

	December31, 2012	December31, 2011
	(millions)	
Commoditycashflowhedges:		
NetdeferredlossesinAOCI	$ (5)	$ (5)
Interestratecashflowhedges:		
NetdeferredlossesinAOCI	(4)	(7)
TotalAOCI	$ (9)	$ (12)

Thefairvalueofourderivativeinstrumentsthata redesignatedashedginginstrumentsandthosethat aremarked-to-marketeach period,andthelocationofeachwithinourconsoli datedbalancesheets,bymajorcategory,issummari zedasfollows:

BalanceSheetLineItem	December31, 2012	December31, 2011
	(millions)	
DerivativeAssetsDesignatedasHedgingInstruments :		
Interestratederivatives:		
Unrealizedgainsonderivative instruments—current	$ —	$ —
Unrealizedgainsonderivative instruments—long-term	—	—
	$ —	$ —
Commodityderivatives:		
Unrealizedgainsonderivative instruments—current	$ —	$ —
Unrealizedgainsonderivative instruments—long-term	—	—
	$ —	$ —
DerivativeAssetsNotDesignatedasHedgingInstrum ents:		
Commodityderivatives:		
Unrealizedgainsonderivative instruments — current	$ 57	$ 107
Unrealizedgainsonderivative instruments—long-term	10	23
	$ 67	$ 130

BalanceSheetLineItem	December31, 2012	December31, 2011
	(millions)	
DerivativeLiabilitiesDesignatedasHedgingInst ruments:		
Interestratederivatives:		
Unrealizedlossesonderivative instruments—current	$ (4)	$ (16)
Unrealizedlossesonderivative instruments—long-term	(2)	(5)
	$ (6)	$ (21)
Commodityderivatives:		
Unrealized losses onderivative instruments—current	$ (3)	$ —
Unrealizedlosseso nderivative instruments—long-term	—	(3)
	$ (3)	$ (3)
DerivativeLiabilitiesNotDesignatedasHedging Instruments:		
Commodityderivatives:		
Unrealizedlossesonderivative instruments — current	$ (58)	$ (97)
Unrealizedlossesonderivative instruments—long-term	(9)	(32)
	$ (67)	$ (129)

Thefollowingtablesummarizestheimpactonourconsolidatedbalancesheetsandconsolidatedstatementsofoperationsofour derivativeinstruments,netofnoncontrollinginterest,thatareaccountedforusingthecashflowhedgemethodofaccountingforeach oftheyearsendedDecember31,2012and2011:

	LossRecognizedin AOCIonDerivatives –EffectivePortion		LossReclassified fromAOCIto Earnings –Effective Portion			Gain(Loss) RecognizedinIncome onDerivatives – IneffectivePortionand AmountExcluded fromEffectiveness Testing			Deferred LossesinAOCI Expectedtobe Reclassified intoEarnings OvertheNext 12Months
	2012	2011	2012	2011		2012	2011		
			(millions)						(millions)
Commodityderivatives	$ (1)	$ (2)	$ (1)	$ —		$ —	$ —		$ —
Interestratederivatives	$ —	$ (3)	$ (3)	$ (6)	(a)	$ —	$ —	(a)(b)	$ (1)

(a) Includedininterestexpenseinourconsolidatedstatementsofoperations.
(b) FortheyearsendedDecember31,2012and2011,noderivativegainsorlosseswerereclassifiedfromAOCItocurrentperiodearningsasa resultofthediscontinuanceofcashflowhedgesrelatedtocertainforecastedtransactionsthatarenotprobableofoccurringorasaresultof exclusionfromeffectivenesstesting.

Changeinvalueofderivativeinstruments,forwhichthehedgemethodofaccountinghasnotbeenelectedfromoneperiodtothe next,arerecordedintheconsolidatedstatementsofoperations.Thefollowingsummarizestheseamountsandthelocationwithinthe consolidatedstatementsofoperationsthatsuchamountsarereflected:

	YearEndedDecember31,		
CommodityDerivatives:StatementofOperationsLine Item	2012	2011	2010
		(millions)	
Realizedgains	$ 86	$ 28	$ 118
Unrealizedgains(losses)...	—	50	(74)
Tradingandmarketinggains,net.......................................	$ 86	$ 78	$ 44

Wedonothaveanyderivativefinancialinstrumentsthatqualifyasahedgeofanetinvestment.

Thefollowingtablesrepresent,bycommoditytype, ournetlongorshortderivativepositions,aswell asthenumberof outstandingcontractsthatareexpectedtopartially orentirelysettleineachrespectiveyear.To the extentthatwehavelongdated derivativepositionsthatspanmultiplecalendaryears,thecontractwillappearinmorethanoneline iteminthetablebelow. Additionally,relativetothehedgingofcertainof ourstorageand/ortransportationassets,wemay executebasistransactionsfor naturalgas,whichmayresultinanetlong/shortposition ofzero.Thistablealsopresentsournetlongorshortnaturalgasbasisswap positionsseparatelyfromournetlongorshortnaturalgaspositions.

	December31,2012								
	CrudeOil		NaturalGas		NaturalGasLiquids			NaturalGas BasisSwaps	
Yearof Expiration	NetShort Position (Bbls)(a)	Number of Contracts	Net Short Position (MMBtu)	Number of Contracts	NetShort Position (Bbls)	Number of Contracts		NetShort Position (MMBtu)	Number of Contracts
2013..................	(1,139,514)	478	(18,670,425)	239	(12,966,380)	410	(b)	(1,615,000)	132
2014..................	(825,500)	119	(365,000)	3	(8,910,000)	4	(c)	(1,350,000)	4
2015..................	(293,000)	13	—	—	—	—		—	—
2016..................	(183,000)	1	—	—	—	—		—	—

(a) Bblsrepresentsbarrels.
(b) Includes34physicalindexbasedderivativecontractstotaling(13,612,800)Bbls.
(c) Includes2physicalindexbasedderivativecontractstotaling(9,000,000)Bbls.

	December31,2011								
	CrudeOil		NaturalGas		NaturalGasLiquids			NaturalGas BasisSwaps	
Yearof Expiration	NetLong (Short) Position (Bbls)	Number of Contracts	NetLong (Short) Position (MMBtu)	Number of Contracts	NetLong (Short) Position (Bbls)	Number of Contracts		NetLong (Short) Position (MMBtu)	Number of Contracts
2012	(1,161,792)	488	(19,768,750)	203	(10,987,055)	427	(a)	10,012,500	190
2013	(797,323)	207	1,835,000	8	(8,966,650)	15	(b)	120,000	22
2014	(619,500)	44	(365,000)	3	(9,000,000)	2	(c)	—	—
2015	(365,000)	2	—	—	—	—		—	—
2016	(183,000)	1	—	—	—	—		—	—

(a) Includes22physicalindexbasedderivativecontractstotaling(11,751,600)barrels,orBbls.
(b) Includes3physicalindexbasedderivativecontractstotaling(9,036,000)Bbls.
(c) Includes2physicalindexbasedderivativecontractstotaling(9,000,000)Bbls.

AsofDecember31,2012,DCPPartnershadinterest rateswapsoutstandingwithindividualnotionalvaluesof$70millionand $80million,which,inaggregate,exchangeupto$150millionofDCPPartners'floatingrateobligationforafixedrateobligation throughJune2014.

12. 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:

Description	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet – Financial Instruments(a)	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet – Financial Instruments(a)	Net Amount
	December 31, 2012			December 31, 2011		
	(millions)					
Assets:						
Commodity derivatives	$ 67	$ (3)	$ 64	$ 130	$ (8)	$ 122
Liabilities:						
Commodity derivatives	$ (70)	$ 3	$ (67)	$ (132)	$ 8	$ (124)
Interest rate derivatives	$ (6)	$ —	$ (6)	$ (21)	$ —	$ (21)

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

13. Equity-Based Compensation

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

	Year Ended December 31, 2012	2011	2010
	(millions)		
DCP Midstream, LLC Long-Term Incentive Plan......	$ 14	$ 25	$ 12
DCP Partners' Long-Term Incentive Plan (DCP Partners' LTIP)...................	2	6	3
Total...	$ 16	$ 31	$ 15

	Vesting Period (years)	Unrecognized Compensation Expense at December 31, 2012 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream LTIP:				
Relative Performance Units (RPUs)................	3	$ —	—	—
Strategic Performance Units (SPUs)..............	3	$ 8	15%-28%	2
Phantom Units...................................	3	$ 4	0%-28%	1
DCP Partners' Phantom Units.....................	3	$ —	28%	1
DCP Partners' LTIP:				
Performance Phantom Units.......................	3	$ —	20-30%	2
Phantom Units...................................	0.5	$ —	—	—
Restricted Phantom Units.........................	1-3	$ —	20-30%	2

DCP Midstream LTIP — Under the DCP Midstream LTIP, awards may be granted to our key employees. The DCP Midstream LTIP provides for the grant of Relative Performance Units, or RPUs, Strategic Performance Units, or SPUs, and Phantom Units. The RPUs, SPUs and Phantom Units consist of a notional unit based on the value of common shares or units of ConocoPhillips, Phillips

66, Spectra Energy and DCP Partners. The DCP Partners' Phantom Units constitute a notional unit equal to the fair value of DCP Partners' common units. 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.

Relative Performance Units— The number of RPUs that will ultimately vest range, in value up to 200% of the outstanding RPUs, 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. After the performance period the value derived from the RPUs is transferred to our Non-Qualified Deferred Compensation plan, and invested according to the participant's investment elections. The DERs are paid in cash at the end of the performance period. The following table presents information related to RPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2010	25,040	$ 44.02	
Transferred to Non-Qualified Executive Deferred Compensation Plan (a)	(25,040)	$ 44.02	
Outstanding at December 31, 2012, 2011 and 2010	—	$ —	$ —

(a) Units vesting in 2010 transferred at 100%.

Strategic Performance Units — The number of SPUs that will ultimately vest range, in value 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 table presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2010	374,917	$ 27.48	
Granted	139,900	$ 30.03	
Forfeited	(7,710)	$ 26.79	
Vested or paid in cash (b)	(166,237)	$ 41.59	
Outstanding at December 31, 2010	340,870	$ 21.66	
Granted	122,020	$ 38.59	
Forfeited	(5,786)	$ 27.15	
Vested or paid in cash (c)	(201,129)	$ 18.51	
Outstanding at December 31, 2011	255,975	$ 34.10	
Granted (a)	173,129	$ 36.98	
Forfeited	(20,067)	$ 35.34	
Vested or paid in cash (d)	(141,650)	$ 30.35	
Outstanding at December 31, 2012	267,387	$ 37.86	$ 39.71
Expected to vest	216,399	$ 37.88	$ 29.09

(a) Includes the impact of conversion of the underlying securities granted under the 2010, 2011 and 2012 LTIP.
(b) The 2008 grants vested at 72%.
(c) The 2009 grants vested at 155%.
(d) The 2010 grants vested at 130%.

The estimate of RPUs and 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 in 2010	166,237	$ 4	$ 2
Vested in 2011	201,129	$ 15	$ 3
Vested in 2012	141,650	$ 8	$ 14

PhantomUnits— TheDERsarepaidquarterlyinarrears.ThefollowingtablepresentsinformationrelatedtoPhantomUnits:

	Units	GrantDate Weighted-AveragePrice PerUnit	Measurement Date Weighted-AveragePrice PerUnit
OutstandingatJanuary1,2010	343,850	$ 25.94	
Granted	139,800	$ 30.04	
Forfeited	(7,690)	$ 27.04	
Vested	(105,670)	$ 40.15	
OutstandingatDecember31,2010	370,290	$ 23.41	
Granted	122,020	$ 38.58	
Forfeited	(1,250)	$ 32.71	
Vested	(268,090)	$ 20.78	
OutstandingatDecember31,2011	222,970	$ 34.68	
Granted(a)	175,490	$ 37.14	
Forfeited	(18,590)	$ 35.34	
Vested	(139,670)	$ 31.98	
OutstandingatDecember31,2012	240,200	$ 38.00	$ 39.74
Expectedtovest	193,061	$ 38.00	$ 39.69

(a) Includestheimpactofconversionoftheunderlying securitiesgrantedunderthe2010,2011and 2012LTIP.

Thefollowingtablepresentsthefairvalueofunitsvestedandtheunit-basedliabilitiespaidforunitbasedawardsrelatedtothe phantomunits:

	Units	FairValueof UnitsVested	Unit-Based LiabilitiesPaid
		(millions)	
Vestedin2010	105,670	$ 3	$ —
Vestedin2011	268,090	$ 8	$ 4
Vestedin2012	139,670	$ 6	$ 9

DCPPartners'PhantomUnits— TheDERsarepaidquarterlyinarrears.Thefollowingtablepresentsinformationrelatedtothe DCPPartners'PhantomUnits:

	Units	GrantDate Weighted-AveragePrice PerUnit	Measurement DatePrice PerUnit
OutstandingatJanuary1,2010	10,750	$ 50.43	
Granted	17,300	$ 35.56	
Vested	(10,750)	$ 31.87	
OutstandingatDecember31,2010	17,300	$ 47.09	
Vested	(5,766)	$ 35.56	
OutstandingatDecember31,2011	11,534	$ 35.56	
Vested	(5,767)	$ 35.56	
OutstandingatDecember31,2012	5,767	$ 35.56	$ 41.75
Expectedtovest	5,767	$ 35.56	$ 41.75

Thefairvalueofunitsthatvested,andtheunit-basedliabilitiespaidduringtheyearsendedDecember31,2012,2011and2010 waslessthan$1millionforallperiods.

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. 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 the grant of DERs. The phantom units consist of a notional unit based on the value of common units or shares of DCP Partners, Spectra Energy, ConocoPhillips and Phillips 66.

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. All awards are subject to cliff vesting.

Performance Phantom Units — DCP Partner's has awarded Performance Phantom Units, or PPUs, pursuant to the LTIP to certain employees. PPUs generally vest in their entirety at the end of a three year performance period. The number of PPUs that will ultimately vest range, in value up to 200% of the outstanding PPUs, depending on the achievement of specified performance targets over three year performance periods. The final performance payout is determined by the board of directors of DCP Partners' general partner. The DERs are paid in cash at the end of the performance period. Of the remaining PPUs outstanding at December 31, 2012, 1,560 units are expected to vest on December 31, 2013 and 1,610 units are expected to vest on December 31, 2014. The following table presents information related to the Performance Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2010	67,140	$ 15.18	
Granted	16,630	$ 31.80	
Forfeited	(2,205)	$ 15.61	
Vested	(14,215)	$ 33.44	
Outstanding at December 31, 2010	67,350	$ 15.42	
Granted	10,580	$ 41.80	
Vested	(50,720)	$ 10.05	
Outstanding at December 31, 2011	27,210	$ 35.69	
Granted (a)	11,740	$ 39.31	
Forfeited	(12,217)	$ 39.22	
Vested (b)	(22,483)	$ 34.91	
Outstanding at December 31, 2012	4,250	$ 39.63	$ 41.31
Expected to vest (c)	3,170	$ 39.76	$ 41.34

(a) Includes the impact of conversion of the underlying securities granted under the 2012 LTIP.
(b) The units vested at 121%.
(c) Based on DCP Partners' December 31, 2012 estimated achievement of specified performance targets, the performance for units granted in 2012 is 100% and for units granted in 2011 is 100%. The estimated forfeiture rate for units granted in 2012 is 30% and for units granted in 2011 is 20%.

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

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

	Year Ended December 31,		
	2012	2011	2010
		(millions)	
Fair value of units vested	$ 1	$ 5	$ —
Unit-based liabilities paid	$ 5	$ —	$ 1

Phantom Units— In conjunction with DCP Partners' initial public offering, in January 2006, the board of directors of DCP Partners' general partner awarded Phantom LPUs, or Phantom Units, to key employees and to directors who are not officers or employees of affiliates of DCP Partners' general partner.

As part of their director fees, DCP Partners granted 4,000 Phantom Units during each of the years ended December 31, 2012 and 2011, respectively, and 5,200 Phantom Units during the year ended December 31, 2010 to directors. All of these units vested in their respective grant years, and were settled in units.

The DERs are paid quarterly in arrears.

The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2010	—	$ —	
Granted	5,200	$ 31.80	
Vested	(5,200)	$ 31.80	
Outstanding at December 31, 2010	—	$ —	
Granted	4,000	$ 41.80	
Vested	(4,000)	$ 41.80	
Outstanding at December 31, 2011	—	$ —	
Granted	4,000	$ 48.03	
Vested	(4,000)	$ 48.03	
Outstanding at December 31, 2012	—	$ —	$ —

The fair value of the units that vested for the years ended December 31, 2012, 2011 and 2010 was less than $1 million for all periods.

RestrictedPhantomUnits —DCPPartners'generalpartner'sboardofdirector sawardedrestrictedphantomLPUs,orRPUs,to keyemployeesundertheLTIP.OftheremainingRPUs outstandingatDecember31,2012,1,560unitsare expectedtoveston December31,2013and1,610unitsareexpectedtov estonDecember31,2014.TheDERsarepaidquarter lyinarrears.Thefollowing tablepresentsinformationrelatedtotheRPUs:

	Units	GrantDate Weighted-AveragePrice perUnit	Measurement DatePrice perUnit
OutstandingatJanuary1,2010	67,140	$ 15.18	
Granted	16,630	$ 31.80	
Forfeited	(2,205)	$ 15.61	
Vested	(14,215)	$ 33.44	
OutstandingatDecember31,2010	67,350	$ 15.42	
Granted	10,580	$ 41.80	
Vested	(58,600)	$ 12.97	
OutstandingatDecember31,2011	19,330	$ 37.27	
Granted(a)	11,740	$ 39.31	
Forfeited	(7,760)	$ 43.27	
Vested	(19,060)	$ 37.31	
OutstandingatDecember31,2012	4,250	$ 39.63	$ 41.31
Expectedtovest	3,170	$ 39.76	$ 41.34

(a) Includestheimpactofconversionoftheunderlying securitiesgrantedunderthe2012LTIP.

Thefollowingtablepresentsthefairvalueofunit svestedandtheunit-basedliabilitiespaidforun itbasedawardsrelatedto RestrictedPhantomUnits:

	YearEnded December31,		
	2012	2011	2010
		(millions)	
Fairvalueofunitsvested	$ 1	$ 3	$ 1
Unit-basedliabilitiespaid	$ 2	$ 1	$ —

TheestimateofRPUsthatareexpectedtovestisb asedonhighlysubjectiveassumptionsthatcouldpo tentiallychangeovertime, includingtheexpectedforfeiturerate,whichwase stimatedat30%forunitsgrantedin2012and20%f orunitsgrantedin2011. Therefore,theamountofunrecognizedcompensation expensenotedabovedoesnotnecessarilyrepresent thevaluethatwillultimately berealizedinourconsolidatedstatementofoperat ions.

DukeEnergy1998LTIPandSpectraEnergy2007LTIP — UndertheDukeEnergy1998LTIP,DukeEnergygrante dcertainof ourkeyemployeesstockoptions,stock-basedperfor manceawards,phantomstockawardsandotherstock awardstobesettledin sharesofDukeEnergy'scommonstock,ortheStock- BasedAwards.Uponexecutionofthe50-50Transacti oninJuly2005,our employeesincurredachangeinstatusfromDukeEne rgyemployeestonon-employees.Asaresult,webeg anaccountingforthese awardsusingthefairvaluemethod.Noawardshave beenandwedonotexpecttosettleanyawardsgran tedundertheDukeEnergy 1998LTIPwithcash.AsofDecember31,2012,allu nitsundertheDukeEnergy1998LTIParevested.

InconnectionwiththeSpectraspin,onereplacemen tDukeEnergyStock-BasedAwardandone-halfSpectr aEnergyStock-Based AwardweredistributedtoeachholderofDukeEnerg yStock-BasedAwardsforeachawardheldatthetim eoftheSpectraspin. SubstantiallyallconvertedStock-BasedAwardsare subjecttothetermsandconditionsapplicabletot heoriginalDukeEnergyStock-BasedAwards.TheSpectraEnergyStock-BasedAwards resultingfromtheconversionareconsideredtoha vebeenissuedunderthe SpectraEnergy2007LTIP,asamendedandrestated.

TheSpectraEnergy2007LTIPprovidesforthegrant ingofstockoptions,restrictedstockawardsandu nits,unrestrictedstock awardsandunits,andotherequity-basedawards,to employeesandotherkeyindividualswhoperformse rvicesforSpectraEnergy.A maximumof40millionsharesofcommonstockmaybe awardedundertheSpectraEnergy2007LTIP,asame ndedandrestated.

Options granted under the Spectra Energy 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms, and vest immediately or over terms not to exceed five years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Restricted, performance and phantom stock awards granted under the Spectra Energy 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair market value of the shares on the date of grant, and the related compensation expense is recognized over the requisite service period which is the same as the vesting period. As of December 31, 2012, all units under the Spectra Energy 2007 LTIP are vested.

Stock Options— Under the Duke Energy 1998 LTIP, the exercise price of each option granted could not be less than the market price of Duke Energy's common stock on the date of grant. Effective July 1, 2005, these options were accounted using the fair value method. As a result, compensation expense subsequent to July 1, 2005, is recognized based on the change in the fair value of the stock options at each reporting date until vesting. As of December 31, 2012, all stock options granted under the Duke and Spectra plans are vested and exercisable.

On July 2, 2012, Duke Energy completed a merger with Progress Energy. Immediately preceding the merger, Duke Energy executed a one-for-three reverse stock split with respect to the issued and outstanding shares of Duke Energy common stock. The following table includes the effects of the reverse stock split on outstanding options.

The following table shows information regarding options to purchase Duke Energy's common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at January 1, 2010	1,166,792	$ 19.34		
Exercised	(56,245)	$ 8.42		
Forfeited	(401,562)	$ 24.19		
Outstanding at December 31, 2010	708,985	$ 17.46		
Exercised	(59,725)	$ 8.90		
Forfeited	(451,700)	$ 21.45		
Outstanding and Exercisable at December 31, 2011	197,560	$ 10.93		
Exercised	(62,809)	$ 10.72		
Forfeited	(42,400)	$ 21.68		
Reverse stock split	(68,368)	$ 7.91		
Outstanding and Exercisable at December 31, 2012	23,983	$ 23.62	0.2	$ 1

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010, was approximately $1 million for all periods.

The following table shows information regarding options to purchase Spectra Energy's common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at January 1, 2010	598,296	$ 28.95	2.4	
Exercised	(33,768)	$ 13.22		
Forfeited	(202,187)	$ 36.55		
Outstanding at December 31, 2010	362,341	$ 26.18		
Exercised	(29,134)	$ 12.43		
Forfeited	(227,150)	$ 32.40		
Outstanding and Exercisable at December 31, 2011	106,057	$ 16.61		
Exercised	(39,661)	$ 12.08		
Forfeited	(23,600)	$ 32.79		
Outstanding and Exercisable at December 31, 2012	42,796	$ 11.89	0.2	$ 1

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010, was less than $1 million for all periods.

Phantom Stock Awards — There were no phantom stock awards granted during the years ended December 31, 2012, 2011 and 2010.

The following tables summarize information about phantom stock awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2010	26,508	$ 15.72	
Vested	(22,516)	$ 15.59	
Outstanding at December 31, 2010	3,992	$ 16.50	
Vested	(3,992)	$ 16.50	
Outstanding at December 31, 2012 and 2011	—	$ —	$ —

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2010	13,254	$ 23.76	
Vested	(11,258)	$ 23.55	
Outstanding at December 31, 2010	1,996	$ 24.94	
Vested	(1,996)	$ 24.94	
Outstanding at December 31, 2012 and 2011	—	$ —	$ —

There were no phantom stock awards which vested during the year ended December 31, 2012. The total fair value of the phantom stock awards that vested during the years ended December 31, 2011 and 2010 was less than $1 million for both periods.

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, 2012, 2011 and 2010 we expensed plan contributions of $27 million, $25 million and $21 million, respectively. In conjunction with the Marysville Hydrocarbons Holdings, LLC, or Marysville, acquisition on December 30, 2010, DCP Partners acquired two 401(k) plans. One of these plans was incorporated into the DCP Midstream 401(k) plan during 2011.

We offer certain eligible executives the opportunity to participate in DCP Midstream LP's Non-Qualified Executive Deferred Compensation Plan. This plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions. The 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. All amounts contributed to or earned by the plan's investments are held in a trust account for the benefit of the participants. The trust and the liability to the 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.

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 became currently payable on January 4, 2011. During 2011, DCP Partners made estimated federal and state tax payments totaling $29 million and less than $1 million, respectively, related to their estimated $35 million tax liability that resulted from the acquisition of Marysville. The remaining $6 million estimated tax liability was reclassified to goodwill in DCP Partners' final accounting for the Marysville business combination.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Accordingly, we have recorded current tax expense for the Texas margin tax. For the years ended December 31, 2011 and 2010, the state of Michigan imposed a business tax of 0.8% on gross receipts and 4.95% of Michigan taxable income. The sum of gross receipts and income tax is subject to a tax surcharge of 21.99%. The Michigan business tax was repealed for the year ended December 31, 2012.

Income tax expense consisted of the following:

	Year Ended December 31,		
	2012	2011	2010
		(millions)	
Current:			
Federal income tax expense	$ —	$ (29)	$ —
State income tax expense	(3)	(10)	(9)
Deferred:			
Federal income tax benefit	3	34	5
State income tax (expense) benefit	(2)	2	(1)
Total income tax expense	$ (2)	$ (3)	$ (5)

We had net long-term deferred tax liabilities of $92 million and $93 million as of December 31, 2012 and 2011, respectively. The net long-term deferred tax liabilities are included in deferred income taxes on the consolidated balance sheets. The deferred tax liabilities of $135 million and $126 million as of December 31, 2012 and 2011, respectively, are primarily associated with

depreciationandamortizationrelatedtotheacquiredintangibleassetsandproperty,plantandequipment.Offsettingthedeferredtax liabilitiesaredeferredtaxassetsrelatedtothenetoperatinglossofanaffiliatecorporationofapproximately$43millionand$33 millionasofDecember31,2012and2011,respectively.Thenetoperatinglossesbeginexpiringin2027.Weexpecttofullyutilize thenetoperatinglosscarryovers,and,accordinglywehavenotprovidedavaluationallowanceforthenetdeferredtaxasset.

Oureffectivetaxratedifersfromstatutoryratesprimarilyduetoourbeingstructuredasalimitedliabilitycompany,whichisa pass-throughentityforfederalincometaxpurposes,whilebeingtreatedasataxableentityincertainstates.Additionally,someofour subsidiariesaretaxpayingentitiesforfederalincometaxpurposes.

16.CommitmentsandContingentLiabilities

Litigation—Themidstreamindustryhasseenanumberofclassactionlawsuitsinvolvingroyaltydisputes,mismeasurementand mispaymentallegations.Wearecurrentlynamedasdefendantsinsomeofthesecasesandcustomershaveassertedindividualaudit claimsrelatedtomismeasurementandmispayment.Managementbelieveswehavemeritoriousdefensestothesecasesand,therefore, willcontinuetodefendthemvigorously.Theseclaims,however,canbecostlyandtimeconsumingtodefend.Wearealsoapartyto variouslegal,administrativeandregulatoryproceedingsthathavearisenintheordinarycourseofourbusiness,including,fromtime totime,disputeswithcustomersovervariousmeasurementandsettlementissues.

Managementcurrentlybelievesthatthesematters,takenasawhole,andafterconsiderationofamountsaccrued,insurance coverageandotherindemnificationarrangements,willnothaveamaterialadverseeffectuponourconsolidatedresultsofoperations, financialpositionorcashflows.

GeneralInsurance—OurinsurancecoverageiscarriedwithanaffiliateofPhillips66,anaffiliateofSpectraEnergyandthird-partyinsurers.Ourinsurancecoverageincludes:(1)generalliabilityinsurancecoveringthird-partyexposures;(2)statutoryworkers' compensationinsurance;(3)automobileliabilityinsuranceforallowned,non-ownedandhiredvehicles;(4)excessliabilityinsurance abovetheestablishedprimarylimitsforgeneralliabilityandautomobileliabilityinsurance;(5)propertyinsurance,whichcoversthe replacementvalueofrealandpersonalpropertyandincludesbusinessinterruption;and(6)directorsandofficersinsurancecovering ourdirectorsandofficersforactsrelatedtoourbusinessactivities.Allcoverageissubjecttocertainlimitsanddeductibles,theterms andconditionsofwhicharecommonforcompanieswithsimilartypesofoperations.

Environmental—Theoperationofpipelines,plantsandotherfacilitiesforgathering,processing,compressing,transporting,or storingnaturalgas,andfractionating,transporting,gathering,processingandstoringNGLsandotherproductsissubjecttostringent andcomplexlawsandregulationspertainingtohealth,safetyandtheenvironment.Asanowneroroperatorofthesefacilities,we mustcomplywithUnitedStateslawsandregulationsatthefederal,stateandlocallevelsthatrelatetoairandwaterquality,hazardous andsolidwastestorage,management,transportationanddisposal,andotherenvironmentalmattersincludingrecentlyadoptedU.S. EnvironmentalProtectionAgencyregulationsrelatedtoreportingofgreenhousegasemissionswhichhavetakeneffectoverthepast twoyears.Thecostofplanning,designing,constructingandoperatingpipelines,plants,andotherfacilitiesmustincorporate compliancewithenvironmentallawsandregulationsandsafetystandards.Inaddition,thereisincreasingfocus,bothfromstateand federalregulatoryofficialsandthroughlitigation,onhydraulicfracturingandtherealorperceivedenvironmentalimpactsofthis technique,whichindirectlypresentssomerisktoouravailablesupplyofnaturalgas.Failuretocomplywiththeselawsand regulationsmaytriggeravarietyofadministrative,civilandpotentiallycriminalenforcementmeasures,includingcitizensuits,which canincludetheassessmentofmonetarypenalties,theimpositionofremedialrequirements,theissuanceofinjunctionsorrestrictions onoperations.Managementbelievesthat,basedoncurrentlyknowninformation,compliancewiththeselawsandregulationswillnot haveamaterialadverseeffectonourconsolidatedresultsofoperations,financialpositionorcashflows.

Wemakeexpendituresinconnectionwithenvironmentalmattersaspartofournormaloperations.AsofDecember31,2012and 2011,environmentalliabilitiesincludedintheconsolidatedbalancesheetsasothercurrentliabilitiesamountedto$5millionand$6 million,respectively,andenvironmentalliabilitiesincludedintheconsolidatedbalancesheetsasotherlong-termliabilitiesamounted to$9millionand$9million,respectively.

OperatingLeases — Weutilizeassetsunderoperatingleasesinseveralareasofoperations.Consolidatedrentalexpense, includingleaseswithnocontinuingcommitment,amountedto$36million,$38millionand$38millionin2012,2011and2010, respectively.Rentalexpenseforleaseswithescalationclausesisrecognizedonastraightlinebasisovertheinitialleaseterm.

Minimumrentalpaymentsunderourvariousoperating leasesintheyearindicatedareasfollows:

	Minimum Rental Payments (millions)
2013	$ 49
2014	39
2015	30
2016	21
2017	16
Thereafter	61
Totalminimumleasepayments	$ 216

17.GuaranteesandIndemnifications

Weperiodicallyenterintoagreementsfortheacqui sition,contributionordivestitureofassets.Thes eagreementscontain indemnificationprovisionsthatmayprovideindemni tyforenvironmental,tax,employment,outstanding litigation,breachesof representations,warrantiesandcovenants,performa nceofDCPPartnersorotherliabilitiesrelatedto theassetsbeingacquired, contributedordivested.Claimsmaybemadebythir dpartiesorDCPPartnersundertheseindemnificati onagreementsforvarious periodsoftimedependingonthenatureoftheclai m.Theeffectiveperiodsontheseindemnificationp rovisionsgenerallyhaveterms ofoneto15years,althoughsomearelonger.Ourm aximumpotentialexposureundertheseindemnificati onagreementscanvary dependingonthenatureoftheclaimandthepartic ulartransaction.Weareunabletoestimatethetot almaximumpotentialamountof futurepaymentsunderindemnificationagreementsdu etoseveralfactors,includinguncertaintyastow hetherclaimswillbemade undertheseindemnities.Wehaveissuedguarantees andindemnificationsforcertainofourconsolidate dsubsidiaries.

18.SupplementalCashFlowInformation

	Year Ended December 31,		
	2012	2011	2010
	(millions)		
Cashpaidforinterest,netofcapitalizedinterest	$ 169	$ 196	$ 256
Cashpaidforincometaxes,netofrefunds	$ 6	$ 37	$ 6
Non-cashinvestingandfinancingactivities :			
Distributionspayabletomembers	$ —	$ 95	$ 77
Property,plantandequipmentacquiredwithaccount spayable	$ 158	$ 118	$ 72
Othernon -cashadditionsofproperty,plantandequipment	$ 59	$ 9	$ 7
Acquisitionrelatedcontingentconsideration	$ —	$ —	$ 4

DuringtheyearsendedDecember31,2012,2011and 2010,wereceiveddistributionsfromDCPPartnerso f$75million,$53 millionand$45million,respectively,whichareel iminatedinconsolidation.

19. Valuation and Qualifying Accounts and Reserves

Our valuation and qualifying accounts and reserves for the years ended December 31, 2012, 2011 and 2010 are as follows:

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Charged to Other Accounts(b)	Deductions(c)	Balance at End of Period
			(millions)		
December 31, 2012:					
Allowance for doubtful accounts	$ 2	$ —	$ —	$ —	$ 2
Environmental	15	2	—	(3)	14
Litigation	3	—	—	(2)	1
Other(a)	1	—	—	(1)	—
	$ 21	$ 2	$ —	$ (6)	$ 17
December 31, 2011:					
Allowance for doubtful accounts	$ 2	$ —	$ —	$ —	$ 2
Environmental	15	3	—	(3)	15
Litigation	2	2	—	(1)	3
Other(a)	3	1	—	(3)	1
	$ 22	$ 6	$ —	$ (7)	$ 21
December 31, 2010:					
Allowance for doubtful accounts	$ 3	$ —	$ —	$ (1)	$ 2
Environmental	16	3	—	(4)	15
Litigation	6	—	—	(4)	2
Other(a)	1	—	4	(2)	3
	$ 26	$ 3	$ 4	$ (11)	$ 22

(a) Principally consists of other contingency reserves, which are included in other current liabilities.
(b) Consists of the fair value of contingent consideration recognized in relation to acquisitions and the purchase of an additional interest in a subsidiary.
(c) Consists of cash payments, collections, reserve reversals, liabilities settled, and the re-measurement of the fair value of contingent consideration.

20. Subsequent Events

We have evaluated subsequent events occurring through February 22, 2013, the date the consolidated financial statements were issued.

On January 28, 2013, DCP Partners announced that the board of directors of DCP Partners' general partner declared a quarterly distribution of $0.69 per unit, payable on February 14, 2013 to unitholders of record on February 7, 2013.

In January 2013, our board of directors approved a $104 million dividend which was paid in January 2013.