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

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# FORM 8-K/A

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## CURRENT REPORT

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

**Date of Report (Date of earliest event reported): March 30, 2012**

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

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

| | |
|---|---|
| **370 17th Street, Suite 2775**<br>**Denver, Colorado** | **80202** |
| (Address of principal executive offices) | (Zip Code) |

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

**(Former name or former address, if changed since last report.)**

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

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

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

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

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

## Explanatory Note

This amended Current Report on Form 8-K/A (this “Form 8-K/A”) is being filed to amend the Current Report on Form 8-K filed by DCP Midstream Partners, LP (the “Partnership”) on April 5, 2012 (the “Initial Form 8-K”), announcing the completion of the transaction entered into between the Partnership, DCP Midstream, LLC (“Midstream”) and DCP LP Holdings, LLC, whereby Midstream contributed to the Partnership the remaining 66.67% interest in Southeast Texas not already owned by the Partnership, commodity derivative instruments related to the Southeast Texas storage business (collectively, the “Southeast Texas Midstream Business”) and fixed price commodity derivatives for a three-year period for aggregate consideration of $240.0 million (the “Transaction”). In connection with the Transaction, the Partnership is hereby amending Item 9.01 of the Initial Form 8-K solely to file (i) as Exhibit 99.2 to this Form 8-K/A, audited combined financial statements of the Southeast Texas Midstream Business as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 and (ii) as Exhibit 99.3 to this Form 8-K/A, unaudited pro forma condensed consolidated financial statements of the Partnership as of December 31, 2011 and for the years ended December 31, 2011, 2010 and 2009.

**Item 9.01 Financial Statements and Exhibits.**

(a) Financial statements of businesses acquired.

Audited combined financial statements of the Southeast Texas Midstream Business as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009, are attached hereto as Exhibit 99.2, and are incorporated herein by reference.

(b) Pro forma financial information.

The unaudited pro forma condensed consolidated financial statements of the Partnership as of December 31, 2011 and for the years ended December 31, 2011, 2010 and 2009, are attached hereto as Exhibit 99.3, and are incorporated herein by reference.

(c) Not applicable.

(d) Exhibits.

| Exhibit Number | Description |
|---|---|
| Exhibit 2.1* | First Amendment to Contribution Agreement, dated March 30, 2012, among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP. |
| Exhibit 10.1* | Fourteenth Amendment to the Omnibus Agreement, dated March 30, 2012, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP and DCP Midstream Operating, LP. |
| Exhibit 23.1 | Consent of Deloitte & Touche LLP on the Southeast Texas Midstream Business Combined Financial Statements as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009. |
| Exhibit 99.1* | Press Release dated April 4, 2012. |
| Exhibit 99.2 | Audited combined financial statements of the Southeast Texas Midstream Business as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009. |
| Exhibit 99.3 | Unaudited pro forma condensed consolidated financial statements of DCP Midstream Partners, LP as of December 31, 2011 and for the years ended December 31, 2011, 2010 and 2009. |

* Previously filed.

## SIGNATURES

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

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

Date: May 31, 2012

By: /s/ Rose M. Robeson
Name: Rose M. Robeson
Title: Senior Vice President and Chief Financial Officer

## EXHIBIT INDEX

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* Previously filed.

**Exhibit 23.1**

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement No. 333-142271 on Form S-8 of DCP Midstream Partners, LP and Registration Statement Nos. 333-167108 and 333-175047 on Form S-3 of DCP Midstream Partners, LP of our report dated February 29, 2012, relating to the combined financial statements of the Southeast Texas Midstream Business (which report expresses an unqualified opinion including an explanatory paragraph referring to the preparation of the combined financial statements from the separate records maintained by DCP Midstream, LLC), appearing in this Current Report on Form 8-K/A of DCP Midstream Partners, LP dated May 31, 2012.

/s/ Deloitte & Touche LLP

Denver, Colorado
May 31, 2012

**Exhibit 99.2**

# THE SOUTHEAST TEXAS MIDSTREAM BUSINESS

## COMBINED FINANCIAL STATEMENTS

## AS OF DECEMBER 31, 2011 AND 2010
## AND THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

**Deloitte & Touche LLP**
Suite 3600
555 Seventeenth Street
Denver, CO 80202-3942
USA

Tel: +1 303 292 5400
Fax: +1 303 312 4000
www.deloitte.com

**INDEPENDENT AUDITORS' REPORT**

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

We have audited the accompanying combined balance sheets of the Southeast Texas Midstream Business (the "Business"), which consists of assets which are under common ownership and common management, as of December 31, 2011 and 2010, and the related combined statements of operations, comprehensive income, changes in net parent equity, and cash flows for each of the three years in the period ended December 31, 2011. These combined financial statements are the responsibility of the Business' management. Our responsibility is to express an opinion on these combined 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 financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Business' internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such combined financial statements present fairly, in all material respects, the combined financial position of the Business at December 31, 2011 and 2010, and the combined results of its operations and its combined cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

The accompanying combined financial statements have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Business had been operated as an unaffiliated entity. Portions of certain expenses represent allocations made from, and are applicable to, DCP Midstream, LLC as a whole.

/s/ Deloitte & Touche LLP

February 29, 2012

Member of
**Deloitte Touche Tohmatsu**

## THE SOUTHEAST TEXAS MIDSTREAM BUSINESS
## COMBINED BALANCE SHEETS

| | December 31, 2011 | 2010 |
|---|---|---|
| | (Millions) | |
| **ASSETS** | | |
| Current assets: | | |
| Cash | $ 0.9 | $ — |
| Accounts receivable: | | |
| Trade | 16.8 | 51.1 |
| Affiliates | 36.6 | 45.2 |
| Inventories | 23.2 | 9.5 |
| Unrealized gains on derivative instruments | 36.0 | 12.6 |
| Other current assets | 0.3 | — |
| Total current assets | 113.8 | 118.4 |
| Property, plant and equipment, net | 317.6 | 281.5 |
| Goodwill, net | 11.9 | 11.9 |
| Intangibles, net | 31.4 | 33.7 |
| Unrealized gains on derivative instruments | 0.1 | 0.5 |
| Other long-term assets | 0.6 | 0.6 |
| Total assets | $475.4 | $446.6 |
| **LIABILITIES AND NET PARENT EQUITY** | | |
| Current liabilities: | | |
| Accounts payable: | | |
| Trade | $ 89.6 | $ 74.3 |
| Affiliates | 0.8 | — |
| Unrealized losses on derivative instruments | 17.5 | 13.6 |
| Capital spending accrual | 1.3 | 9.5 |
| Other | 2.1 | 6.7 |
| Total current liabilities | 111.3 | 104.1 |
| Unrealized losses on derivative instruments | 2.6 | 0.2 |
| Other long-term liabilities | 2.5 | 4.5 |
| Total liabilities | 116.4 | 108.8 |
| Commitments and contingent liabilities | | |
| Equity: | | |
| Parent equity | 364.3 | 340.5 |
| Accumulated other comprehensive loss | (5.3) | (2.7) |
| Total net parent equity | 359.0 | 337.8 |
| Total liabilities and net parent equity | $475.4 | $446.6 |

See accompanying notes to combined financial statements.

## THE SOUTHEAST TEXAS MIDSTREAM BUSINESS
## COMBINED STATEMENTS OF OPERATIONS

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (Millions) | | |
| Operating revenues: | | | |
| Sales of natural gas, NGLs and condensate | $247.1 | $416.8 | $274.4 |
| Sales of natural gas, NGLs and condensate to affiliates | 518.1 | 395.7 | 241.9 |
| Transportation, processing and other | 9.0 | 13.2 | 9.7 |
| Transportation, processing and other to affiliates | — | 1.8 | — |
| Gains from commodity derivative activity, net | 12.8 | 12.5 | 8.9 |
| Gains (losses) from commodity derivative activity, net — affiliates | 1.6 | (1.1) | 0.6 |
| Total operating revenues | 788.6 | 838.9 | 535.5 |
| Operating costs and expenses: | | | |
| Purchases of natural gas and NGLs | 702.8 | 749.7 | 471.5 |
| Purchases of natural gas and NGLs from affiliates | 0.4 | 0.8 | 0.6 |
| Operating and maintenance expense | 20.3 | 18.5 | 14.5 |
| Depreciation and amortization expense | 19.6 | 14.4 | 12.0 |
| General and administrative expense | 1.0 | — | — |
| General and administrative expense — affiliates | 10.0 | 12.1 | 10.8 |
| Other income | — | (1.0) | — |
| Loss on sale of assets | — | — | 0.5 |
| Total operating costs and expenses | 754.1 | 794.5 | 509.9 |
| Operating income | 34.5 | 44.4 | 25.6 |
| Income tax benefit (expense) | 0.1 | (1.2) | (0.4) |
| Net income | $ 34.6 | $ 43.2 | $ 25.2 |

See accompanying notes to combined financial statements.

**THE SOUTHEAST TEXAS MIDSTREAM BUSINESS**
**COMBINED STATEMENTS OF COMPREHENSIVE INCOME**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | | (Millions) | |
| Net income | $34.6 | $43.2 | $25.2 |
| Other comprehensive loss: | | | |
| Net unrealized losses on cash flow hedges | (2.6) | — | (2.0) |
| Total other comprehensive loss | (2.6) | — | (2.0) |
| Total comprehensive income | $32.0 | $43.2 | $23.2 |

See accompanying notes to combined financial statements.

## THE SOUTHEAST TEXAS MIDSTREAM BUSINESS
## COMBINED STATEMENTS OF CHANGES IN NET PARENT EQUITY

| | Parent Equity | Accumulated Other Comprehensive Loss | Net Parent Equity |
|---|---|---|---|
| | | (Millions) | |
| **Balance, January 1, 2009** | $218.3 | $ (0.7) | $ 217.6 |
| Net change in parent advances | (28.5) | — | (28.5) |
| Comprehensive income (loss): | | | |
| Net income | 25.2 | — | 25.2 |
| Net unrealized losses on cash flow hedges | — | (2.0) | (2.0) |
| Total comprehensive income (loss) | 25.2 | (2.0) | 23.2 |
| **Balance, December 31, 2009** | 215.0 | (2.7) | 212.3 |
| Net change in parent advances | 82.3 | — | 82.3 |
| Comprehensive income: | | | |
| Net income | 43.2 | — | 43.2 |
| Total comprehensive income | 43.2 | — | 43.2 |
| **Balance, December 31, 2010** | 340.5 | (2.7) | 337.8 |
| Net change in parent advances | 9.3 | — | 9.3 |
| Contributions | 64.8 | — | 64.8 |
| Distributions | (84.9) | — | (84.9) |
| Comprehensive income (loss): | | | |
| Net income | 34.6 | — | 34.6 |
| Net unrealized losses on cash flow hedges | — | (2.6) | (2.6) |
| Total comprehensive income (loss) | 34.6 | (2.6) | 32.0 |
| **Balance, December 31, 2011** | $364.3 | $ (5.3) | $ 359.0 |

See accompanying notes to combined financial statements.

## THE SOUTHEAST TEXAS MIDSTREAM BUSINESS
## COMBINED STATEMENTS OF CASH FLOWS

| | Year Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | (Millions) | | |
| OPERATING ACTIVITIES: | | | |
| Net income | $ 34.6 | $ 43.2 | $ 25.2 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Loss on sale of assets | — | — | 0.5 |
| Depreciation and amortization expense | 19.6 | 14.4 | 12.0 |
| Other, net | (0.2) | (0.9) | 0.1 |
| Change in operating assets and liabilities, which provided (used) cash: | | | |
| Accounts receivable | 42.2 | (54.0) | 2.1 |
| Inventories | (13.7) | 10.0 | (13.8) |
| Net unrealized (gains) losses on derivative instruments | (19.3) | 4.4 | — |
| Accounts payable | 17.2 | 4.2 | 19.8 |
| Other current assets and liabilities | (1.9) | 0.4 | (0.7) |
| Other long-term assets and liabilities | (0.8) | (0.1) | (0.4) |
| Net cash provided by operating activities | 77.7 | 21.6 | 44.8 |
| INVESTING ACTIVITIES: | | | |
| Capital expenditures | (61.5) | (25.2) | (17.4) |
| Purchase of Ceritas | — | (78.8) | — |
| Proceeds from sale of assets | — | 0.1 | 1.1 |
| Other investing | (0.1) | — | — |
| Net cash used in investing activities | (61.6) | (103.9) | (16.3) |
| FINANCING ACTIVITIES: | | | |
| Net change in parent advances | 4.9 | 82.3 | (28.5) |
| Payment of distributions to partners | (84.9) | — | — |
| Contributions from partners | 64.8 | — | — |
| Net cash (used in) provided by financing activities | (15.2) | 82.3 | (28.5) |
| Net change in cash and cash equivalents | 0.9 | — | — |
| Cash and cash equivalents, beginning of period | — | — | — |
| Cash and cash equivalents, end of period | $ 0.9 | $ — | $ — |

See accompanying notes to combined financial statements

## 1. Description of Business and Basis of Presentation

DCP Southeast Texas Holdings, GP, or Southeast Texas, is engaged in the business of gathering, processing, compressing, transporting, treating and storing natural gas and transporting, gathering, treating and processing natural gas liquids, or NGLs. The operations, located in Southeast Texas, include 3 natural gas processing facilities with a total capacity of approximately 400 million cubic feet per day. The facilities are connected to our 36-mile Liberty gathering system and to our CIPCO system, which includes 675 miles of gathering and transmission lines, as well as our 3 salt dome natural gas storage caverns at Spindletop with a total capacity of 9 billion cubic feet. Southeast Texas is currently constructing a fourth storage cavern at Spindletop, which is expected to be completed in the third quarter of 2013.

Southeast Texas is owned 66.66% by DCP Southeast Texas, LLC, a wholly-owned subsidiary of DCP Midstream, LLC, or DCP Midstream, 33.33% by DCP Partners SE Texas LLC, a wholly-owned subsidiary of DCP Assets Holdings, LP, or DCP Partners, and 0.01% by Gas Supply Resources Holdings, Inc. a wholly-owned subsidiary of DCP Midstream, LLC, or GSR. DCP Midstream is a joint venture owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. As of December 31, 2011, DCP Midstream owned an approximate 27% interest, including a 1% general partner interest, in DCP Partners. Throughout this report, DCP Midstream, DCP Partners and GSR will together be referenced as “the Partners.”

These combined financial statements include the accounts of Southeast Texas and commodity derivative instruments related to the Southeast Texas storage business, or the Storage Commodity Hedges, together the Southeast Texas Midstream Business, we, our, or us. DCP Partners acquired from DCP Midstream a 33.33% interest in Southeast Texas, on January 1, 2011, the Drop-down Transaction. Certain assets and liabilities presented with the December 31, 2010 balance sheet were excluded from the Drop-down Transaction, and as such are not included in the 2011 results of the Southeast Texas Midstream Business. These excluded assets and liabilities are defined within the Contribution Agreement and include (1) other short-term liabilities of $3.2 million and (2) other long-term liabilities of $1.2 million, and result in a net equity impact of $4.4 million. These combined financial statements also include realized losses of $4.9 million from the Storage Commodity Hedges, which are included as net change in parent advances. The Drop-down Transaction was a transaction between entities under common control and a change in reporting entity.

The combined financial statements include the accounts of the Southeast Texas Midstream Business and its wholly-owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The combined financial statements of the Southeast Texas Midstream Business were prepared from the separate records maintained by DCP Midstream and may not necessarily be indicative of the conditions that would have existed, or the results of operations, if Southeast Texas had been operated as an unaffiliated entity. Because a direct ownership relationship did not exist among all the various assets comprising Southeast Texas until January 1, 2011, DCP Midstream’s contributions and distributions are shown as net change in parent advances in lieu of contributions and distributions in the combined statements of changes in parents’ equity. Intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream operations have been identified in the combined financial statements as transactions between affiliates. In the opinion of management, all adjustments have been reflected that are necessary for a fair presentation of the combined financial statements.

## 2. Summary of Significant Accounting Policies

***Use of Estimates*** — Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the combined 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.

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

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

***Asset Retirement Obligations*** — Asset retirement obligations, or AROs, 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 AROs for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

***Goodwill and Intangible Assets*** — Goodwill is the cost of an acquisition less the fair value of the net assets and liabilities assumed 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 use a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and 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 primarily of customer contracts. These intangible assets are amortized on a straight-line basis over the term of the contract or anticipated relationship. 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 eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- significant adverse change in legal factors or business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management's intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

***Distributions*** — Under the terms of the joint venture agreement, Southeast Texas is required to make quarterly distributions to the owners based on available cash. The terms of the joint venture agreement provide that DCP Partners' distributions from Southeast Texas for the first seven years related to storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to DCP Midstream, GSR and DCP Partners' respective ownership interests in Southeast Texas. During the year ended December 31, 2011, distributions totaled $84.9 million.

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

| Classification of Contract | Accounting Method | Presentation of Gains & Losses or Revenue & Expense |
|---|---|---|
| Non-Trading Derivative Activity | Mark-to-market method (a) | Net basis in gains and losses from commodity derivative activity |
| Cash Flow Hedge | Hedge method (b) | Gross basis in the same combined statements of operations category as the related hedged item |

(a) Mark-to-market — An accounting method whereby the change in the fair value of the asset or liability is recognized in the combined statements of operations in gains and losses from commodity derivative activity during the current period.

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

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

The fair value of a derivative designated as a cash flow hedge is recorded in the combined balance sheets as unrealized gains or unrealized losses on derivative instruments. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in net parents' equity as Accumulated Other Comprehensive Income, or AOCI, and the ineffective portion is recorded in the combined statements of operations. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the combined statements of operations in the same accounts as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the combined balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

*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.

***Revenue Recognition*** — We generate the majority of our revenues from natural gas gathering, and NGL processing, compressing and transporting, as well as marketing of natural gas. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees from the producers.

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 natural gas; 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 transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.
- *Percent-of-proceeds/liquids arrangements* — Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas, NGLs and condensate based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas, NGLs and condensate, regardless of the actual amount of the sales proceeds we receive. We keep the difference between the proceeds received and the amount remitted back to the producer. Under percent-of-liquids arrangements, we do not keep any amounts related to residue natural gas proceeds and only keep amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. Certain of these arrangements may also result in our returning all or a portion of the producer's share of residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Additionally, these arrangements may include fee-based components. Our revenues under percent-of-proceeds arrangements relate directly with the price of natural gas, NGLs and condensate. Our revenues under percent-of-liquids arrangements relate directly with the price of NGLs and condensate.

Our marketing of natural gas 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 reasonably assured 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 combined 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 non-trading commodity derivative activity net in the combined statements of operations as gains and losses from commodity derivative activity. These activities include mark-to-market gains and losses on energy marketing contracts and the settlement of financial or physical energy marketing contracts.

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as accounts receivable or accounts payable using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash.

***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.

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

***Income Taxes*** — We are treated as a partnership for federal income tax purposes. We do not pay federal income taxes. We are subject to the Texas margin tax. We follow the asset and liability method of accounting for state 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. We have calculated current and deferred income taxes as if we were a separate tax payer.

## 3. Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2011-11 “Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities,”*** **or ASU 2011-11** — In December 2011, the FASB issued ASU 2011-11, which amends Accounting Standards Codification, or ASC, Topic 210 “Balance Sheet.” ASU 2011-11 will require entities to disclose information about offsetting and related arrangements to enable financial statement users to understand the effect of such arrangements on the statement of financial position. The provisions of ASU 2011-11 are effective for annual reporting periods beginning on or after January 1, 2013 and we are currently assessing the impact of adoption on our combined results of operations, cash flows and financial position.

***ASU 2011-08 “Intangibles – Goodwill and Other (Topic 350),”*** **or ASU 2011-08** — In September 2011, the FASB issued ASU 2011-08, which amends ASC Topic 350 “Intangibles — Goodwill and Other.” ASU 2011-08 provides additional guidance on the two-step test for goodwill impairment as previously described in Topic 350 “Intangibles — Goodwill and Other.” Under the new guidance, entities may elect to first assess qualitative factors instead of calculating the fair value of a reporting unit unless the entity determines that it is more likely than not the fair value of the reporting unit is less than its carrying value. This ASU is effective for annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with early adoption permitted. There was no impact from the adoption of ASU 2011-08 on our combined results of operations, cash flows and financial position.

***ASU 2011-04 “Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs,”*** **or ASU 2011-04** — In May 2011, the FASB issued ASU 2011-04 which amends ASC Topic 820 “Fair Value Measurements and Disclosures” to change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, clarify the FASB’s intent about the application of existing fair value measurement requirements, and change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The provisions of ASU 2011-04 are effective for annual reporting periods beginning after December 15, 2011 and we are currently assessing the impact of adoption on our combined results of operations, cash flows and financial position.

## 4. Agreements and Transactions with Affiliates

### DCP Midstream, LLC

During the year ended December 31, 2011, in accordance with the partnership agreement, we were billed for certain expenses which were paid by DCP Midstream and totaled $10.0 million for the year ended December 31, 2011. These expenses are included in general and administrative expense — affiliates in the combined statements of operations.

Prior to January 1, 2011, costs incurred by DCP Midstream on our behalf for salaries and benefits of operating personnel, as well as capital expenditures, maintenance and repair costs, and taxes were directly allocated to us. DCP Midstream provided centralized corporate functions on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. DCP Midstream recorded the accrued liabilities and prepaid expenses for general and administrative expenses in its financial statements, including liabilities related to payroll, short and long-term incentive plans, employee retirement and medical plans, paid time off, audit, tax, insurance and other service fees. Our share of those costs was allocated based on DCP Midstream's proportionate investment (consisting of property, plant and equipment, intangibles, and investments in unconsolidated affiliates) compared to our investment.

DCP Midstream has issued parental guarantees in favor of certain counterparties. A portion of these parental guarantees relate to assets included in these combined financial statements.

We participate in DCP Midstream's cash management program. As a result, prior to January 1, 2011, Southeast Texas had no cash balances on the combined balance sheets and all of our cash management activity was performed by DCP Midstream on our behalf, including collection of receivables, payment of payables, and the settlement of sales and purchases transactions with DCP Midstream, which were recorded as parent advances and are included in net parent equity on the accompanying combined balance sheets. During the years ended December 31, 2011 and 2010, cash management activities were performed by DCP Midstream for all transactions related to the Storage Commodity Hedges.

We currently, and anticipate to continue to, purchase from and sell to DCP Midstream in the ordinary course of business. DCP Midstream was a significant customer during the years ended December 31, 2011, 2010 and 2009.

### ConocoPhillips

We currently, and anticipate to continue to, sell to ConocoPhillips in the ordinary course of business. ConocoPhillips was a significant customer during the years ended December 31, 2011, 2010 and 2009.

**Summary of Transactions with Related Parties and Affiliates**

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (Millions) | | |
| DCP Midstream: | | | |
| Sales of natural gas, NGLs and condensate | $481.5 | $358.4 | $216.5 |
| Purchases of natural gas and NGLs | $ 0.4 | $ 0.8 | $ 0.4 |
| Gains (losses) from commodity derivative activity, net | $ 0.6 | $ (0.7) | $ (0.1) |
| General and administrative expense | $ 10.0 | $ 12.1 | $ 10.8 |
| ConocoPhillips: | | | |
| Sales of natural gas, NGLs and condensate | $ 36.6 | $ 37.3 | $ 25.1 |
| Transportation, processing and other | $ — | $ 1.8 | $ — |
| Purchases of natural gas and NGLs | $ — | $ — | $ 0.1 |
| Gains (losses) on derivative activity, net | $ 1.0 | $ (0.4) | $ 0.7 |
| Spectra Energy: | | | |
| Sales of natural gas, NGLs and condensate | $ — | $ — | $ 0.3 |
| Purchases of natural gas and NGLs | $ — | $ — | $ 0.1 |
| Operating and maintenance expense (a) | $ — | $ (0.3) | $ 0.2 |
| Other: | | | |
| Operating and maintenance expense (b) | $ — | $ — | $ (0.2) |

(a) Relates to insurance recoveries received for Hurricane Rita.

(b) Balance for the year ended December 31, 2009 includes hurricane insurance recovery receivables, which were treated as a reduction to operating expense in the accompanying combined statements of operations.

We had balances with related parties and affiliates as follows:

| | December 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (Millions) | |
| DCP Midstream: | | |
| Accounts receivable | $33.8 | $38.6 |
| Accounts payable | $ (0.8) | $ — |
| Unrealized losses on derivative instruments — long-term | $ (2.6) | $ — |
| ConocoPhillips: | | |
| Accounts receivable | $ 2.7 | $ 6.3 |
| Unrealized gains on derivative instruments — current | $ 2.5 | $ 0.1 |
| Unrealized losses on derivative instruments — current | $ (2.0) | $ (0.3) |
| Spectra Energy: | | |
| Accounts receivable | $ 0.1 | $ 0.3 |

## 5. Property, Plant and Equipment

Property, plant and equipment by classification is as follows:

| | Depreciable Life | December 31, 2011 | December 31, 2010 |
|---|---|---|---|
| | | (Millions) | |
| Gathering and transmission systems | 15 —30 Years | $ 180.9 | $ 175.8 |
| Processing and storage facilities | 0 — 50 Years | 226.2 | 221.4 |
| Other | 0 — 30 Years | 2.7 | 2.3 |
| Construction work in progress | | 67.3 | 24.2 |
| Property, plant and equipment | | 477.1 | 423.7 |
| Accumulated depreciation | | (159.5) | (142.2) |
| Property, plant and equipment, net | | $ 317.6 | $ 281.5 |

The above amounts include accrued capital expenditures of $1.3 million, $9.5 million and $0.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. There was no interest capitalized on construction projects for the years ended December 31, 2011, 2010, and 2009. As of December 31, 2011, we had $4.2 million of non-cancelable purchase obligations for capital projects.

Depreciation expense was $17.3 million, $13.2 million and $12.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

***Asset Retirement Obligations*** — Asset retirement obligations, included in other long-term liabilities in the combined balance sheets, are $1.0 million and $0.9 million at December 31, 2011 and 2010, respectively. Accretion expense was $0.1 million for each of the years ended December 31, 2011, 2010 and 2009.

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.

## 6. Goodwill and Intangible Assets

At December 31, 2011 and 2010, we had goodwill of $11.9 million as a result of the amount that we recognized in connection with our acquisition of the Raywood processing plant and Liberty gathering system from Ceritas Holdings, LP, or Ceritas, in 2010.

The change in carrying amount of goodwill is as follows:

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| | (Millions) | |
| Beginning of period | $11.9 | $ — |
| Acquisitions | — | 11.9 |
| End of period | $11.9 | $11.9 |

Intangible assets consist primarily of customer contracts, and are as a result of our acquisition of the Raywood processing plant and Liberty gathering system from Ceritas in 2010. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying combined balance sheets as intangible assets, net, and are as follows:

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| | (Millions) | |
| Gross carrying amount | $34.9 | $34.9 |
| Accumulated amortization | (3.5) | (1.2) |
| Intangible assets, net | $31.4 | $33.7 |

For the years ended December 31, 2011 and 2010, we recorded amortization expense of $2.3 million and $1.2 million, respectively. As of December 31, 2011, the remaining amortization period was 13.5 years.

Estimated amortization for these intangibles is as follows as of December 31, 2011:

| Estimated Future Amortization | |
|---|---|
| (Millions) | |
| 2012 | $ 2.3 |
| 2013 | 2.3 |
| 2014 | 2.3 |
| 2015 | 2.3 |
| 2016 | 2.3 |
| Thereafter | 19.9 |
| Total | $ 31.4 |

## 7. Fair Value Measurement

### *Determination of Fair Value*

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, which are measured at fair value. Fair values are generally based upon quoted market prices, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an "exit price" methodology, in line with how we believe a marketplace participant would value that asset or liability. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.
- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.
- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

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

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 8 Risk Management and Hedging Activities.

***Valuation Hierarchy***

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the input that requires the highest degree of judgment in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

***Commodity Derivative Assets and Liabilities***

We enter into a variety of derivative financial instruments, which may include over the counter, or OTC, instruments, such as natural gas contracts.

We typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas price changes. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. These instruments are generally classified as Level 2. Depending upon market conditions and our strategy, we may enter into OTC derivative positions with a significant time horizon to maturity, and market prices for these OTC derivatives may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent that it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

### *Nonfinancial Assets and Liabilities*

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

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

The following table presents the financial instruments carried at fair value as of December 31, 2011 and 2010, by combined balance sheet caption and by valuation hierarchy as described above:

| | December 31, 2011 | | | | December 31, 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total Carrying Value | Level 1 | Level 2 | Level 3 | Total Carrying Value |
| | (Millions) | | | | | | | |
| Current assets: | | | | | | | | |
| Commodity derivatives (a) | $ — | $ 36.0 | $ — | $ 36.0 | $ — | $ 12.6 | $ — | $ 12.6 |
| Long-term assets: | | | | | | | | |
| Commodity derivatives (b) | $ — | $ 0.1 | $ — | $ 0.1 | $ — | $ 0.5 | $ — | $ 0.5 |
| Current liabilities: | | | | | | | | |
| Commodity derivatives (c) | $ — | $(17.5) | $ — | $ (17.5) | $ — | $(13.6) | $ — | $ (13.6) |
| Acquisition related contingent consideration (d) | $ — | $ — | $ — | $ — | $ — | $ — | $ (2.1) | $ (2.1) |
| Long-term liabilities: | | | | | | | | |
| Commodity derivatives (e) | $ — | $ (2.6) | $ — | $ (2.6) | $ — | $ (0.2) | $ — | $ (0.2) |

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

### *Changes in Level 3 Fair Value Measurements*

The table below illustrates a rollforward of the amounts included in our combined balance sheets for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the “Transfers into Level 3” and “Transfers out of Level 3” captions.

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities. During the year ended December 31, 2011, we had no derivative financial instruments classified as Level 3.

| | Commodity Derivative Instruments | | | |
|---|---|---|---|---|
| | Current Assets | Long-Term Assets | Current Liabilities | Long-Term Liabilities |
| | (Millions) | | | |
| **Year ended December 31, 2010:** | | | | |
| Beginning balance | $ 0.8 | $ 0.5 | $ (0.8) | $ (0.3) |
| Net realized and unrealized gains (losses) included in earnings | 0.1 | (0.5) | — | 0.3 |
| Transfers into Level 3 (a) | — | — | — | — |
| Transfers out of Level 3 (a) | (0.5) | — | 0.3 | — |
| Purchases, issuances and settlements, net | (0.4) | — | 0.5 | — |
| Ending balance | $ — | $ — | $ — | $ — |
| Net unrealized gains (losses) still held included in earnings (b) | $ — | $ — | $ — | $ — |

(a) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(b) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to change in unrealized gains or losses relating to assets and liabilities classified as Level 3 that are still held as of December 31, 2010.

During the year ended December 31, 2011, we settled the $2.1 million contingent consideration, which was classified as Level 3, associated with our acquisition of the Raywood processing plant and Liberty gathering system from Ceritas. During the year ended December 31, 2010, we recognized the fair value of contingent consideration of $3.1 million in relation to our acquisition of the Raywood processing plant and Liberty gathering system, which was recorded to other current liabilities in our combined balance sheets. During the year ended December 31, 2010, we reassessed the $3.1 million fair value of the contingent consideration and adjusted the liability to $2.1 million. Accordingly, we recognized approximately $1.0 million in other income in our combined statements of operations during the year ended December 31, 2010.

During the years ended December 31, 2011 and 2010, we had no transfers into or out of Levels 1 and 2. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level in the current period.

***Estimated Fair Value of Financial Instruments***

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

The fair value of accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments. Unrealized gains and unrealized losses on derivative instruments are carried at fair value.

## 8. Risk Management and Hedging Activities

Our day to day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell and the creditworthiness of each of our counterparties. We manage certain of these exposures with both physical and financial transactions. All of our derivative activities are conducted under the governance of DCP Midstream’s internal Risk Management Committees that establish policies, limiting exposure to market risk and requiring daily reporting to management of potential financial exposure. These policies include statistical risk tolerance limits using historical price movements to calculate daily value at risk. The following briefly describes each of the risks that we manage.

**Commodity Price Risk**

Our natural gas asset based activities engage in the business of marketing energy related products and services, including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy marketing operations are exposed to market variables and commodity price risk with respect to these products and services, and we may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. We manage commodity price risk related to owned natural gas storage and pipeline assets by engaging in natural gas asset based marketing activities. The commercial activities related to our natural gas asset based marketing primarily consist of time spreads and basis spreads.

We may execute a time spread transaction when the difference between the current price of natural gas (cash or futures) and the futures market price for natural gas exceeds our cost of storing physical gas in our owned and/or leased storage facilities. The time spread transaction allows us to lock in a margin when this market condition exists. A time spread transaction is executed by establishing a long gas position at one point in time and establishing a corresponding short gas position at a different point in time. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period combined statements of operations. While gas held in our storage location is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facility are recorded at fair value and any changes in fair value are currently recorded in our combined 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 combined 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.

Additionally, in order for our storage facility to remain operational, we maintain a minimum level of base gas in our storage cavern, which is capitalized on our combined balance sheets as a component of property, plant and equipment, net. In the fourth quarter of 2008 we commenced a capacity expansion project for one of our storage caverns, which required us to sell all of the base gas within the cavern. During 2009, the expansion project was completed and base gas was repurchased to restore our storage cavern to operation. To mitigate the risk associated with the forecasted re-purchase of base gas, we executed a series of derivative financial instruments, which were designated as cash flow hedges. The cash paid upon settlement of these hedges economically offsets the cash paid to purchase the base gas. A deferred loss of $2.7 million was recognized and will remain in AOCI until such time that our cavern is emptied and the base gas is sold. In conjunction with our construction of a fourth storage cavern, we have applied additional base gas derivatives which are classified as cash flow hedges. These cash flow hedges were in a loss position of $2.6 million as of December 31, 2011 and will fluctuate in value through the term of construction. Following completion of the fourth cavern, the cash flow hedges will remain in AOCI until the cavern is emptied and the base gas is sold.

**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 DCP Midstream was to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties may have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.
- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under those agreements and the amount of the default is above certain predefined thresholds, which are significantly high. As of December 31, 2011, we are not a party to any agreements that would be subject to these provisions.

Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features.

Depending upon the movement of commodity prices, each of our individual contracts with counterparties to our commodity derivative instruments are in either a net asset or net liability position. As of December 31, 2011, we had $2.0 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, 2011, if a credit-risk related event were to occur we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2011, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to less than $0.1 million.

**Summarized Derivative Information**

The following summarizes the balance within AOCI relative to our commodity cash flow hedges:

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| | (Millions) | |
| Commodity cash flow hedges: | | |
| Net deferred losses in AOCI | $(5.3) | $(2.7) |

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

| Balance Sheet Line Item | December 31, 2011 | December 31, 2010 | Balance Sheet Line Item | December 31, 2011 | December 31, 2010 |
|---|---|---|---|---|---|
| | (Millions) | | | (Millions) | |
| **Derivative Assets Designated as Hedging Instruments:** | | | **Derivative Liabilities Designated as Hedging Instruments:** | | |
| **Commodity derivatives:** | | | **Commodity derivatives:** | | |
| Unrealized gains on derivative instruments – current | $— | $— | Unrealized losses on derivative instruments – current | $ — | $ — |
| Unrealized gains on derivative instruments – long-term | — | — | Unrealized losses on derivative instruments – long-term | (2.6) | — |
| | $— | $ — | | $ (2.6) | $ — |
| **Derivative Assets Not Designated as Hedging Instruments:** | | | **Derivative Liabilities Not Designated as Hedging Instruments:** | | |
| **Commodity derivatives:** | | | **Commodity derivatives:** | | |
| Unrealized gains on derivative instruments – current | $36.0 | $12.6 | Unrealized losses on derivative instruments – current | $(17.5) | $(13.6) |
| Unrealized gains on derivative instruments – long-term | 0.1 | 0.5 | Unrealized losses on derivative instruments – long-term | — | (0.2) |
| | $ 36.1 | $ 13.1 | | $(17.5) | $(13.8) |

The following table summarizes the impact on our combined balance sheet and combined statements of operations of our derivative instruments that are accounted for using the cash flow hedge method of accounting.

| | Loss Recognized in AOCI on Derivatives — Effective Portion 2011 | 2010 | Gain (Loss) Recognized in Income on Derivatives — Ineffective Portion and Amount Excluded from Effectiveness Testing (a) 2011 | 2010 | Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months |
|---|---|---|---|---|---|
| | (Millions) | | (Millions) | | (Millions) |
| Commodity derivatives | $ (2.6) | $ — | $ — | $ — | $ — |

(a) For the years ended December 31, 2011 and 2010, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

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

| Commodity Derivatives: Statements of Operations Line Item | Year Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | (Millions) | | |
| **Third party:** | | | |
| Realized (losses) gains | $ (7.9) | $18.8 | $ 9.5 |
| Unrealized gains (losses) | 20.7 | (6.3) | (0.6) |
| Gains from commodity derivative activity, net | $12.8 | $12.5 | $ 8.9 |
| **Affiliates:** | | | |
| Realized gains (losses) | $ 3.0 | $ (0.5) | $ 0.2 |
| Unrealized (losses) gains | (1.4) | (0.6) | 0.4 |
| Gains (losses) from commodity derivative activity, net — affiliates | $ 1.6 | $ (1.1) | $ 0.6 |

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

The following tables represent, by commodity type, our net long or short positions that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the table below. Additionally, relative to the hedging of certain of our storage and/or transportation assets, we may execute basis transactions for natural gas, which may result in a net long/short position of zero. This table also presents our net long or short natural gas basis swap positions separately from our net long or short natural gas positions.

| | December 31, 2011 | |
|---|---|---|
| Year of Expiration | Natural Gas Net Long (Short) Position (MMBtu) | Natural Gas Basis Swaps Net Long (Short) Position (MMBtu) |
| 2012 | (16,570,000) | 14,357,500 |
| 2013 | 2,000,000 | 3,600,000 |

| | December 31, 2010 | |
|---|---|---|
| Year of Expiration | Natural Gas Net Long (Short) Position (MMBtu) | Natural Gas Basis Swaps Net Long (Short) Position (MMBtu) |
| 2011 | (7,272,500) | 6,025,000 |
| 2012 | — | 8,220,000 |

## 9. Income Taxes

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Accordingly, we have recorded tax expense for the Texas margin tax.

Income tax expense consists of the following:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | | (Millions) | |
| Current: | | | |
| State | $(0.8) | $(0.7) | $(0.5) |
| Deferred: | | | |
| State | 0.9 | (0.5) | 0.1 |
| Total income tax benefit (expense) | $ 0.1 | $(1.2) | $(0.4) |

We had net long-term deferred tax liabilities of $1.6 million and $2.5 million as of December 31, 2011 and 2010, respectively. The net long-term deferred tax liabilities are included in other long-term liabilities on the combined balance sheets and are primarily associated with depreciation and amortization related to property.

## 10. Commitments and Contingent Liabilities

***Litigation*** — We are not party to any significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our combined results of operations, financial position, or cash flows.

ExxonMobil has alleged that in February 2011 we delivered off-specification NGLs to ExxonMobil's Beaumont, Texas fractionation facility. We continue to investigate this claim; weather conditions may have affected the quality of certain NGL volumes delivered to ExxonMobil in February 2011. We are currently in discussions with ExxonMobil to resolve this dispute. As a result of this claim, we have recorded a liability of $0.5 million. This amount is included in our combined balance sheets as of December 31, 2011 within accounts payable – trade.

***General Insurance*** — An affiliate of the Southeast Texas Midstream Business carries insurance for our assets and operations, which management believes is consistent with companies engaged in similar commercial operations with similar assets. These insurance coverages include (i) general liability; (ii) excess liability insurance above the established primary limits of general liability insurance; and (iii) property insurance, which covers replacement value of real and personal property and includes business interruption/extra expense. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operation.

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

As of December 31, 2011 and 2010, we had no environmental liabilities in our combined balance sheets.

## 11. Supplemental Cash Flow Information

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | | (Millions) | |
| Cash paid for income taxes, net of income tax refunds | $— | $ 0.4 | $ 0.7 |
| Non-cash investing and financing activities: | | | |
| Net change in parent advances | $ 4.4 | $ — | $— |
| Other non-cash additions of property, plant and equipment | $ 1.6 | $10.1 | $ 0.3 |
| Acquisition related contingent consideration | $— | $ 2.1 | $— |

## 12. Subsequent Events

We have evaluated subsequent events occurring through February 29, 2012, the date the combined financial statements were issued.

On February 27, 2012, DCP Midstream entered into agreements to contribute its remaining 66.7% interest in Southeast Texas and the Storage Commodity Hedges for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. This transaction is expected to close by the second quarter of 2012. This transaction represents a transaction between entities under common control and a change in reporting entity. Following this transaction, our results will be combined into the results of DCP Partners.

**Exhibit 99.3**

**UNAUDITED DCP MIDSTREAM PARTNERS, LP**
**PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

References to we, us or our, refer to DCP Midstream Partners, LP and its consolidated subsidiaries (the “Partnership”). On February 27, 2012, DCP Midstream Partners, LP entered into a transaction (the “Transaction”) with DCP Midstream, LLC (“Midstream”) and DCP LP Holdings, LLC. The Transaction closed on March 30, 2012. In the Transaction, Midstream contributed to the Partnership the remaining 66.67% interest in DCP Southeast Texas Holdings, GP (“Southeast Texas”) not already owned by the Partnership, commodity derivative instruments related to the Southeast Texas storage business (“Storage Commodity Hedges”) (collectively, the “Southeast Texas Midstream Business”) and fixed price commodity derivatives for a three-year period (“NGL Hedges”) for aggregate consideration of $240.0 million. The Transaction was ultimately funded by a combination of debt and equity, with 20% of the consideration funded by the issuance to Midstream of additional common units of the Partnership.

The transfer of assets between Midstream and the Partnership represents a transfer of assets between entities under common control. Midstream is the owner of the Partnership’s general partner. The Southeast Texas system is a fully integrated midstream business which includes: 675 miles of natural gas pipelines; three natural gas processing plants totaling 400 MMcf/d of processing capacity; natural gas storage assets with 9 Bcf of existing storage capacity; and NGL market deliveries directly to Exxon Mobil and to Mont Belvieu via the Partnership’s Black Lake NGL pipeline.

On January 1, 2011, the Partnership acquired its initial 33.33% interest in Southeast Texas from Midstream. The acquisition was completed in accordance with the Purchase and Sale Agreement and the Contribution Agreement, each dated November 4, 2010, between the Partnership and Midstream.

The unaudited pro forma condensed consolidated financial statements present the impact on our financial position and results of operations of our acquisition of the remaining 66.67% interest in Southeast Texas and the Storage Commodity Hedges. Since the NGL Hedges are for periods subsequent to the dates of the unaudited pro forma condensed consolidated financial statements, there are no pro forma adjustments related to the NGL Hedges. The unaudited pro forma condensed consolidated financial statements as of December 31, 2011 and for the years ended December 31, 2011, 2010 and 2009 have been prepared based on certain pro forma adjustments to our financial statements within our Annual Report on Form 10-K for the year ended December 31, 2011, filed on February 29, 2012 with the Securities and Exchange Commission, and are qualified in their entirety by reference to such historical consolidated financial statements and related notes contained therein. The unaudited pro forma condensed consolidated financial statements should be read in conjunction with the accompanying notes and with the historical consolidated financial statements and related notes thereto.

The unaudited pro forma condensed consolidated balance sheet as of December 31, 2011 has been prepared as if the Transaction had occurred on that date. The unaudited pro forma condensed consolidated statements of operations for the years ended December 31, 2011, 2010 and 2009 have been prepared as if the Transaction had occurred on January 1, 2009. Since the Transaction represents a transaction between entities under common control and a change in reporting entity, the unaudited pro forma condensed consolidated financial statements are combined on an “as if” pooling basis. Accordingly, the historic impact of the acquired assets and liabilities are carried forward.

The pro forma adjustments are based upon currently available information and certain estimates and assumptions; therefore, actual results may differ from the pro forma adjustments. Management believes, however, that the assumptions provide a reasonable basis for presenting the significant effects of the Transaction and that the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited pro forma condensed consolidated financial statements.

The unaudited pro forma condensed consolidated financial statements may not be indicative of the results that would have actually occurred if we had owned our additional interest in the Southeast Texas Midstream Business during the periods presented.

## DCP MIDSTREAM PARTNERS, LP
## UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET
## DECEMBER 31, 2011
## (Millions)

| | DCP Midstream Partners, LP | Pro Forma Adjustments - Remove Southeast Texas 33.3% Investment (a) | Pro Forma Adjustments - Acquisition of Southeast Texas Midstream Business (b) | Pro Forma Adjustments - Consolidation | DCP Midstream Partners, LP Pro Forma |
|---|---|---|---|---|---|
| **ASSETS** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ 6.7 | $ — | $ 0.9 | $ — | $ 7.6 |
| Accounts receivable | 161.4 | — | 53.4 | — | 214.8 |
| Other | 71.8 | — | 59.5 | — | 131.3 |
| Total current assets | 239.9 | — | 113.8 | — | 353.7 |
| Property, plant and equipment, net | 1,181.8 | — | 317.6 | 1.2 **(c)** | 1,500.6 |
| Goodwill and intangible assets, net | 255.8 | — | 43.3 | — | 299.1 |
| Investments in unconsolidated affiliates | 208.7 | (101.6) | — | — | 107.1 |
| Other non-current assets | 17.4 | — | 0.7 | — | 18.1 |
| Total assets | $ 1,903.6 | $ (101.6) | $ 475.4 | $ 1.2 | $ 2,278.6 |
| **LIABILITIES AND EQUITY** | | | | | |
| Current liabilities: | | | | | |
| Accounts payable | $ 188.1 | $ — | $ 90.4 | $ — | $ 278.5 |
| Other | 81.1 | — | 20.9 | — | 102.0 |
| Total current liabilities | 269.2 | — | 111.3 | — | 380.5 |
| Long-term debt | 746.8 | — | — | 108.0 **(f)** | 854.8 |
| Other long-term liabilities | 46.7 | — | 5.1 | — | 51.8 |
| Total liabilities | 1,062.7 | — | 116.4 | 108.0 | 1,287.1 |
| Commitments and contingent liabilities | | | | | |
| Equity: | | | | | |
| Predecessor equity | — | — | 364.3 | (364.3)**(d)** | — |
| Common unitholders | 654.4 | (103.4) | — | 103.4 **(d)** | 654.4 |
| | — | — | — | 48.0 **(e)** | 48.0 |
| | — | — | — | 84.0 **(e)** | 84.0 |
| | — | — | — | 22.1 **(d)** | 22.1 |
| General partner interest | (4.7) | — | — | — | (4.7) |
| Accumulated other comprehensive loss | (21.2) | 1.8 | (5.3) | — | (24.7) |
| Total partners' equity | 628.5 | (101.6) | 359.0 | (106.8) | 779.1 |
| Non-controlling interests | 212.4 | — | — | — | 212.4 |
| Total equity | 840.9 | (101.6) | 359.0 | (106.8) | 991.5 |
| Total liabilities and equity | $ 1,903.6 | $ (101.6) | $ 475.4 | $ 1.2 | $ 2,278.6 |

See accompanying notes to unaudited pro forma condensed consolidated financial statements.

## DCP MIDSTREAM PARTNERS, LP
## UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS
## YEAR ENDED DECEMBER 31, 2011
## (Millions, except per unit amounts)

| | DCP Midstream Partners, LP | Pro Forma Adjustments - Remove Southeast Texas 33.3% Investment (a) | Pro Forma Adjustments - Acquisition of Southeast Texas Midstream Business (b) | Pro Forma Adjustments - Consolidation | DCP Midstream Partners, LP Pro Forma |
|---|---|---|---|---|---|
| Total operating revenues | $ 1,569.8 | $ — | $ 788.6 | $ — | $ 2,358.4 |
| Operating costs and expenses: | | | | | |
| Purchases of natural gas, propane and NGLs | 1,229.8 | — | 703.2 | — | 1,933.0 |
| Operating and maintenance expense | 105.4 | — | 20.3 | — | 125.7 |
| Depreciation and amortization expense | 81.0 | — | 19.6 | — | 100.6 |
| General and administrative expense | 37.3 | — | 11.0 | — | 48.3 |
| Other | (0.5) | — | — | — | (0.5) |
| Total operating costs and expenses | 1,453.0 | — | 754.1 | — | 2,207.1 |
| Operating income | 116.8 | — | 34.5 | — | 151.3 |
| Interest income | — | — | — | — | — |
| Interest expense | (33.9) | — | — | (5.3) **(g)** | (39.2) |
| Earnings from unconsolidated affiliates | 36.9 | (14.2) | — | — | 22.7 |
| Income before income taxes | 119.8 | (14.2) | 34.5 | (5.3) | 134.8 |
| Income tax expense | (0.6) | — | 0.1 | — | (0.5) |
| Net income | 119.2 | (14.2) | 34.6 | (5.3) | 134.3 |
| Net income attributable to non-controlling interests | (18.8) | — | — | — | (18.8) |
| Net income attributable to partners | 100.4 | (14.2) | 34.6 | (5.3) | 115.5 |
| Less: | | | | | |
| Net income attributable to predecessor operations | — | — | — | — | — |
| General partner interest in net income | (25.2) | | | | (26.7) |
| Net income allocable to limited partners | $ 75.2 | | | | $ 88.8 |
| Net income per limited partner unit — basic | $ 1.73 | | | | $ 1.91 |
| Net income per limited partner unit — diluted | $ 1.72 | | | | $ 1.91 |
| Weighted-average limited partner units outstanding — basic | 43.5 | | | 2.8 **(e)** | 46.3 |
| Weighted-average limited partner units outstanding — diluted | 43.6 | | | 2.8 **(e)** | 46.4 |

See accompanying notes to unaudited pro forma condensed consolidated financial statements.

**DCP MIDSTREAM PARTNERS, LP**

**UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS**

**YEAR ENDED DECEMBER 31, 2010**

**(Millions, except per unit amounts)**

| | DCP Midstream Partners, LP | Pro Forma Adjustments - Remove Southeast Texas 33.3% Investment (a) | Pro Forma Adjustments - Acquisition of Southeast Texas Midstream Business (b) | Pro Forma Adjustments - Consolidation | DCP Midstream Partners, LP Pro Forma |
|---|---|---|---|---|---|
| Total operating revenues | $ 1,269.5 | $ — | $ 838.9 | $ — | $ 2,108.4 |
| Operating costs and expenses: | | | | | |
| Purchases of natural gas, propane and NGLs | 1,032.6 | — | 750.5 | — | 1,783.1 |
| Operating and maintenance expense | 79.8 | — | 18.5 | — | 98.3 |
| Depreciation and amortization expense | 73.7 | — | 14.4 | — | 88.1 |
| General and administrative expense | 33.7 | — | 11.1 | — | 44.8 |
| Other | (13.1) | — | — | — | (13.1) |
| Total operating costs and expenses | 1,206.7 | — | 794.5 | — | 2,001.2 |
| Operating income | 62.8 | — | 44.4 | — | 107.2 |
| Interest income | — | — | — | — | — |
| Interest expense | (29.1) | — | — | (5.3) **(g)** | (34.4) |
| Earnings from unconsolidated affiliates | 38.2 | (14.4) | — | — | 23.8 |
| Income before income taxes | 71.9 | (14.4) | 44.4 | (5.3) | 96.6 |
| Income tax expense | (0.3) | — | (1.2) | — | (1.5) |
| Net income | 71.6 | (14.4) | 43.2 | (5.3) | 95.1 |
| Net income attributable to non-controlling interests | (9.2) | — | — | — | (9.2) |
| Net income attributable to partners | 62.4 | (14.4) | 43.2 | (5.3) | 85.9 |
| Less: | | | | | |
| Net income attributable to predecessor operations | (14.4) | 14.4 | | | — |
| General partner interest in net income | (16.9) | | | | (18.4) |
| Net income allocable to limited partners | $ 31.1 | | | | $ 67.5 |
| Net income per limited partner unit — basic and diluted | $ 0.86 | | | | $ 1.73 |
| Weighted-average limited partner units outstanding — basic and diluted | 36.1 | | | 2.8 **(e)** | 38.9 |

See accompanying notes to unaudited pro forma condensed consolidated financial statements.

## DCP MIDSTREAM PARTNERS, LP

## UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS

## YEAR ENDED DECEMBER 31, 2009

## (Millions, except per unit amounts)

| | DCP Midstream Partners, LP | Pro Forma Adjustments - Remove Southeast Texas 33.3% Investment (a) | Pro Forma Adjustments - Acquisition of Southeast Texas Midstream Business (b) | Pro Forma Adjustments - Consolidation | DCP Midstream Partners, LP Pro Forma |
|---|---|---|---|---|---|
| Total operating revenues | $ 942.4 | $ — | $ 535.5 | $ — | $ 1,477.9 |
| Operating costs and expenses: | | | | | |
| Purchases of natural gas, propane and NGLs | 776.2 | — | 472.1 | — | 1,248.3 |
| Operating and maintenance expense | 69.7 | — | 14.5 | — | 84.2 |
| Depreciation and amortization expense | 64.9 | — | 12.0 | — | 76.9 |
| General and administrative expense | 32.3 | — | 11.3 | — | 43.6 |
| Total operating costs and expenses | 943.1 | — | 509.9 | — | 1,453.0 |
| Operating (loss) income | (0.7) | — | 25.6 | — | 24.9 |
| Interest income | 0.3 | — | — | — | 0.3 |
| Interest expense | (28.3) | — | — | (5.3) **(g)** | (33.6) |
| Earnings from unconsolidated affiliates | 26.9 | (8.4) | — | — | 18.5 |
| (Loss) income before income taxes | (1.8) | (8.4) | 25.6 | (5.3) | 10.1 |
| Income tax expense | (0.6) | — | (0.4) | — | (1.0) |
| Net (loss) income | (2.4) | (8.4) | 25.2 | (5.3) | 9.1 |
| Net income attributable to non-controlling interests | (8.3) | — | — | — | (8.3) |
| Net (loss) income attributable to partners | (10.7) | (8.4) | 25.2 | (5.3) | 0.8 |
| Less: | | | | | |
| Net (loss) income attributable to predecessor operations | (7.4) | 8.4 | | | 1.0 |
| General partner interest in net loss | (12.7) | | | | (14.1) |
| Net (loss) allocable to limited partners | $ (30.8) | | | | $ (12.3) |
| Net (loss) per limited partner unit — basic and diluted | $ (0.99) | | | | $ (0.36) |
| Weighted-average limited partner units outstanding — basic and diluted | 31.2 | | | 2.8 **(e)** | 34.0 |

See accompanying notes to unaudited pro forma condensed consolidated financial statements.

## NOTES TO UNAUDITED DCP MIDSTREAM PARTNERS, LP PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

### Note 1. Basis of Presentation

The unaudited pro forma condensed consolidated financial statements present the impact on our financial position and results of operations of our acquisition (the "Transaction") from DCP Midstream, LLC ("Midstream") of the remaining 66.67% interest in DCP Southeast Texas Holdings, GP ("Southeast Texas"), commodity derivative instruments related to the Southeast Texas storage business ("Storage Commodity Hedges") (collectively, the "Southeast Texas Midstream Business") and fixed price commodity derivatives ("NGL Hedges"). The unaudited pro forma condensed consolidated financial statements as of December 31, 2011 and for the years ended December 31, 2011, 2010 and 2009 have been prepared based on certain pro forma adjustments to our audited consolidated financial statements set forth in our Annual Report on Form 10-K filed on February 29, 2012 with the Securities and Exchange Commission, and are qualified in their entirety by reference to such historical consolidated financial statements and related notes contained in that report. The unaudited pro forma condensed consolidated financial statements should be read in conjunction with the accompanying notes and with the historical consolidated financial statements and related notes thereto.

The unaudited pro forma condensed consolidated balance sheet as of December 31, 2011 has been prepared as if the Transaction occurred on that date. The unaudited pro forma condensed consolidated statements of operations for the years ended December 31, 2011, 2010 and 2009 have been prepared as if the Transaction had occurred on January 1, 2009. We owned a 33.33% interest in Southeast Texas prior to this Transaction, which was accounted for under the equity method of accounting. Subsequent to the Transaction, we own a 100% interest in Southeast Texas and account for Southeast Texas as a consolidated subsidiary. Since the Transaction represents a transaction between entities under common control and a change in reporting entity, the unaudited pro forma condensed consolidated financial statements are combined on an "as if" pooling basis. Accordingly, the historic impact of the acquired assets and liabilities are carried forward.

The pro forma adjustments are based upon currently available information and certain estimates and assumptions; therefore, actual adjustments will differ from the pro forma adjustments. Management believes, however, that the assumptions provide a reasonable basis for presenting the significant effects of the Transaction as contemplated, and that the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited pro forma condensed consolidated financial statements.

The unaudited pro forma condensed consolidated financial statements may not be indicative of the results that would have actually occurred if we had owned the additional interest in Southeast Texas during the periods presented.

The pro forma condensed consolidated financial statements reflect the Transaction as follows:

- the issuance of 2,845,760 limited partner units to finance the Transaction, of which 1,000,417 were issued directly to Midstream;
- the assumed borrowing of $108.0 million under our 4.95% 10-year senior notes due 2022 to finance the Transaction; and
- the acquisition of the remaining 66.67% interest in Southeast Texas and the Storage Commodity Hedges.

We also acquired fixed price NGL Hedges for a three-year period, valued at a $39.5 million net asset position as of March 30, 2012. Certain of the NGL Hedges were valued at $26.4 million and represent consideration for the termination of a fee-based Storage Agreement we had with Midstream; the remaining portion of the NGL Hedges, valued at $14.9 million, mitigate a portion of our currently anticipated commodity price risk associated with the gathering and processing portion of the 66.67% interest in Southeast Texas acquired in the Transaction. Since the NGL Hedges are for periods subsequent to the dates of the unaudited pro forma condensed consolidated financial statements, there are no pro forma adjustments related to the NGL Hedges.

### Note 2. Pro Forma Adjustments and Assumptions

(a) Reflects adjustments to eliminate the investment and equity earnings previously recognized for our historical 33.33% interest in Southeast Texas.

(b) Reflects addition of 100% of the Southeast Texas Midstream Business.

(c) Reflects the interest capitalized by Midstream during the construction of property, plant and equipment at Southeast Texas Midstream Business. As the standalone Southeast Texas Midstream Business did not issue debt, the interest cost incurred by Midstream to construct assets of the Southeast Texas Midstream Business was capitalized by Midstream rather than by the Southeast Texas Midstream Business. As this Transaction is between entities under common control, the amount is included in the book value of assets contributed in the Transaction.

(d) Reflects the acquisition from Midstream of the remaining 66.67% interest in Southeast Texas and the Storage Commodity Hedges and consolidation of our 100.0% interest. The adjustments also reflect the consolidation elimination of the Southeast Texas Midstream Business partners' equity of $364.3 million. The Transaction will be recorded at historical cost as it is considered a transaction between entities under common control. The consideration was allocated as follows, subject to customary post-closing adjustments:

| | (Millions) |
|---|---|
| Aggregate consideration | $ 240.0 |
| Historical cost of the Storage Commodity Hedges | (18.6) |
| Historical capitalized interest related to Southeast Texas assets | (1.2) |
| Historical cost of the remaining 66.67% interest in Southeast Texas | (242.3) |
| Adjustment to partners' equity for deficit consideration | $ (22.1) |

(e) Reflects the issuance of 1,000,417 common units to Midstream valued at $48.0 million, and the net proceeds to us of $84.0 million from the sale of 1,845,343 common units. Consistent with our overall targeted debt and equity ratio to finance our growth, the financing of the Transaction consisted of 55% from the sale of common units and 45% from borrowings.

(f) Reflects $108.0 million of the proceeds from the issuance of debt securities in March 2012 used to fund the Transaction. Consistent with our overall targeted debt and equity ratio to finance our growth, the financing of the Transaction consisted of 45% from borrowings and 55% from the sale of common units.

(g) Reflects the increase in interest expense associated with the incremental debt for the Transaction. On March 13, 2012, the Partnership closed on a public offering of $350.0 million of its 4.95% 10-year senior notes due 2022. A portion of the proceeds of this debt was ultimately used to fund the Transaction.

The effect of a 0.125% variance in interest rates on pro forma interest expense would have been approximately $0.1 million annually.

### Note 3. Pro Forma Net Income or Loss Per Limited Partner Unit

Our net income or net loss is allocated to the general partner and the limited partners, including the holders of subordinated units, through the date of subordinated conversion, in accordance with their respective ownership percentages, after allocating Available Cash generated during the period in accordance with our partnership agreement.

Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

These required disclosures do not impact our overall net income or loss or other financial results; however, in periods in which aggregate net income exceeds certain distribution levels, it will have the impact of reducing net income per limited partner unit, or LPU.

Basic and diluted net income or loss per LPU is calculated by dividing limited partners' interest in pro forma net income or loss, by the weighted average number of outstanding LPUs during the period, assuming the 2,845,760 limited partner units issued in connection with the Transaction since January 1, 2009.