CONSOL Energy Inc
Form 10-Q
August 01, 2012

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

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.

For the quarterly period ended June 30, 2012

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number: 001-14901

CONSOL Energy Inc.
(Exact name of registrant as specified in its charter)

Delaware	51-0337383
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1000 CONSOL Energy Drive
Canonsburg, PA 15317-6506
(724) 485-4000
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller Reporting Company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Shares outstanding as of July 19, 2012

Common stock, $0.01 par value	227,628,861

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PART I
FINANCIAL INFORMATION

ITEM 1. CONDENSED FINANCIAL STATEMENTS

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)
(Dollars in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Sales—Outside	$1,189,293	$1,486,000	$2,500,764	$2,871,478
Sales—Gas Royalty Interests	9,533	16,273	21,739	35,108
Sales—Purchased Gas	651	1,162	1,490	2,142
Freight—Outside	49,472	59,572	98,765	96,440
Other Income	205,538	24,921	258,499	48,137
Total Revenue and Other Income	1,454,487	1,587,928	2,881,257	3,053,305
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	856,889	927,399	1,760,930	1,741,108
Loss on Debt Extinguishment	—	16,090	—	16,090
Gas Royalty Interests Costs	7,124	14,366	17,373	31,173
Purchased Gas Costs	869	1,776	1,386	2,452
Freight Expense	49,472	59,572	98,765	96,251
Selling, General and Administrative Expenses	33,732	43,423	72,731	83,619
Depreciation, Depletion and Amortization	153,824	157,800	309,171	306,862
Abandonment of Long-Lived Assets	—	115,479	—	115,479
Interest Expense	56,593	64,597	114,713	131,079
Taxes Other Than Income	84,329	88,642	175,956	179,331
Total Costs	1,242,832	1,489,144	2,551,025	2,703,444
Earnings Before Income Taxes	211,655	98,784	330,232	349,861
Income Taxes	58,945	21,400	80,326	80,328
Net Income	152,710	77,384	249,906	269,533
Add: Net Loss Attributable to Noncontrolling Interest	29	—	29	—
Net Income Attributable to CONSOL Energy Inc. Shareholders	$152,739	$77,384	$249,935	$269,533
Earnings Per Share:				
Basic	$0.67	$0.34	$1.10	$1.19
Dilutive	$0.67	$0.34	$1.09	$1.18
Weighted Average Number of Common Shares Outstanding:				
Basic	227,548,394	226,647,752	227,408,832	226,499,994
Dilutive	229,252,185	229,138,024	229,122,594	228,917,335
Dividends Paid Per Share	$0.125	$0.100	$0.250	$0.200

The accompanying notes are an integral part of these financial statements.

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CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)
(Dollars in thousands)

	Three Months Ended June 30		Six Months Ended June 30,	
	2012	2011	2012	2011
Net Income	$ 152,710	$ 77,384	$ 249,906	$ 269,533
Other Comprehensive Income (Loss):				
Treasury Rate Lock (Net of tax: $-, $47, $-, $59)	—	(76)	—	(96)
Actuarially Determined Long-Term Liability Adjustments				
Change in Prior Service Cost (Net of tax: $-, $-, ($30,295), $-)	—	—	50,276	—
Amortization of Prior Service Cost (Net of tax: $5,232, $4,583, $9,784, $9,166)	(8,683)	(7,364)	(16,237)	(14,729)
Amortization of Net Loss (Net of tax: ($9,802), ($13,108), ($19,956), ($22,874))	16,269	21,064	33,120	36,756
Net Increase in the Value of Cash Flow Hedge (Net of tax: ($6,869), ($18,308), ($55,877), ($21,122))	10,663	28,430	86,739	32,801
Reclassification of Cash Flow Hedges from OCI to Earnings (Net of tax: $36,696, $10,839, $68,077, $23,454)	(57,847)	(16,905)	(105,788)	(35,745)
Other Comprehensive Income (Loss):	(39,598)	25,149	48,110	18,987
Comprehensive Income	113,112	102,533	298,016	288,520
Add: Comprehensive Loss Attributable to Noncontrolling Interest	29	—	29	—
Comprehensive Income Attributable to CONSOL Energy Inc. Shareholders	$ 113,141	$ 102,533	$ 298,045	$ 288,520

The accompanying notes are an integral part of these financial statements.

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	(Unaudited) June 30, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$200,207	$375,736
Accounts and Notes Receivable:		
Trade	416,838	462,812
Notes Receivables	314,646	314,950
Other Receivables	99,597	105,708
Inventories	305,061	258,335
Deferred Income Taxes	148,977	141,083
Prepaid Expenses	195,297	239,353
Total Current Assets	1,680,623	1,897,977
Property, Plant and Equipment:		
Property, Plant and Equipment	14,736,339	14,087,319
Less—Accumulated Depreciation, Depletion and Amortization	5,065,462	4,760,903
Total Property, Plant and Equipment—Net	9,670,877	9,326,416
Other Assets:		
Deferred Income Taxes	439,745	507,724
Restricted Cash	20,365	22,148
Investment in Affiliates	209,273	182,036
Notes Receivable	300,307	300,492
Other	276,706	288,907
Total Other Assets	1,246,396	1,301,307
TOTAL ASSETS	$12,597,896	$12,525,700

The accompanying notes are an integral part of these financial statements.

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands, except per share data)

	(Unaudited) June 30, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts Payable	$472,804	$522,003
Current Portion of Long-Term Debt	20,862	20,691
Accrued Income Taxes	35,065	75,633
Other Accrued Liabilities	744,186	770,070
Total Current Liabilities	1,272,917	1,388,397
Long-Term Debt:		
Long-Term Debt	3,122,234	3,122,234
Capital Lease Obligations	53,032	55,189
Total Long-Term Debt	3,175,266	3,177,423
Deferred Credits and Other Liabilities:		
Postretirement Benefits Other Than Pensions	2,971,297	3,059,671
Pneumoconiosis Benefits	175,611	173,553
Mine Closing	441,670	406,712
Gas Well Closing	144,577	124,051
Workers' Compensation	150,007	151,034
Salary Retirement	208,506	269,069
Reclamation	56,184	39,969
Other	131,549	124,936
Total Deferred Credits and Other Liabilities	4,279,401	4,348,995
TOTAL LIABILITIES	8,727,584	8,914,815
Stockholders' Equity:		
Common Stock, $.01 Par Value; 500,000,000 Shares Authorized, 227,628,661 Issued and 227,593,906 Outstanding at June 30, 2012; 227,289,426 Issued and 227,056,212 Outstanding at December 31, 2011	2,276	2,273
Capital in Excess of Par Value	2,262,159	2,234,775
Preferred Stock, 15,000,000 shares authorized, None issued and outstanding	—	—
Retained Earnings	2,359,609	2,184,737
Accumulated Other Comprehensive Loss	(753,444)	(801,554)
Common Stock in Treasury, at Cost—34,755 Shares at June 30, 2012 and 233,214 Shares at December 31, 2011	(609)	(9,346)
Total CONSOL Energy Inc. Stockholders' Equity	3,869,991	3,610,885
Noncontrolling Interest	321	—
TOTAL EQUITY	3,870,312	3,610,885
TOTAL LIABILITIES AND EQUITY	$12,597,896	$12,525,700

The accompanying notes are an integral part of these financial statements.

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Dollars in thousands, except per share data)

	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total CONSOL Energy Inc. Stockholders' Equity	Non-Controlling Interest	Total Equity
Balance at December 31, 2011	$2,273	$2,234,775	$2,184,737	$(801,554)	$(9,346)	$3,610,885	$—	$3,610,885
(Unaudited)								
Net Income (Loss)	—	—	249,935	—	—	249,935	(29)	249,906
Other Comprehensive Income	—	—	—	48,110	—	48,110	—	48,110
Comprehensive Income (Loss)	—	—	249,935	48,110	—	298,045	(29)	298,016
Issuance of Common Stock	3	454	—	—	—	457	—	457
Issuance of Treasury Stock	—	—	(18,230)	—	8,737	(9,493)	—	(9,493)
Tax Cost From Stock-Based Compensation	—	(5)	—	—	—	(5)	—	(5)
Amortization of Stock-Based Compensation Awards	—	26,935	—	—	—	26,935	—	26,935
Net Change in Greenshale Energy Noncontrolling Interest	—	—	—	—	—	—	350	350
Dividends ($0.25 per share)	—	—	(56,833)	—	—	(56,833)	—	(56,833)
Balance at June 30, 2012	$2,276	$2,262,159	$2,359,609	$(753,444)	$(609)	$3,869,991	$321	$3,870,312

The accompanying notes are an integral part of these financial statements.

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(Dollars in thousands)

	Six Months Ended June 30,	
	2012	2011
Operating Activities:		
Net Income Attributable to CONSOL Energy Inc. Shareholders	$249,935	$269,533
Adjustments to Reconcile Net Income to Net Cash Provided By Operating Activities:		
Depreciation, Depletion and Amortization	309,171	306,862
Abandonment of Long-Lived Assets	—	115,479
Stock-Based Compensation	26,935	25,575
Gain on Sale of Assets	(189,981)	(5,139)
Loss on Debt Extinguishment	—	16,090
Amortization of Mineral Leases	3,631	3,578
Deferred Income Taxes	30,625	7,592
Equity in Earnings of Affiliates	(15,103)	(11,312)
Changes in Operating Assets:		
Accounts and Notes Receivable	40,034	(51,097)
Inventories	(46,726)	(1,708)
Prepaid Expenses	19,709	23,679
Changes in Other Assets	10,604	15,307
Changes in Operating Liabilities:		
Accounts Payable	(41,266)	21,184
Other Operating Liabilities	(65,693)	23,391
Changes in Other Liabilities	23,456	29,607
Other	12,618	6,862
Net Cash Provided by Operating Activities	367,949	795,483
Investing Activities:		
Capital Expenditures	(714,399)	(585,441)
Proceeds from Sales of Assets	252,229	7,480
Distributions From, net of (Investments In), Equity Affiliates	(21,839)	3,870
Net Cash Used in Investing Activities	(484,009)	(574,091)
Financing Activities:		
Payments on Short-Term Borrowings	—	(23,250)
Payments on Miscellaneous Borrowings	(4,662)	(7,105)
Payments on Long Term Notes, including Redemption Premium	—	(265,785)
Payments on Securitization Facility	—	(130,000)
Proceeds from Issuance of Long-Term Notes	—	250,000
Tax Benefit from Stock-Based Compensation	1,608	4,181
Dividends Paid	(56,833)	(45,293)
Issuance of Common Stock	457	—
Issuance of Treasury Stock	109	5,012
Debt Issuance and Financing Fees	(148)	(15,427)
Net Cash Used In Financing Activities	(59,469)	(227,667)
Net Decrease in Cash and Cash Equivalents	(175,529)	(6,275)
Cash and Cash Equivalents at Beginning of Period	375,736	32,794
Cash and Cash Equivalents at End of Period	$200,207	$26,519

The accompanying notes are an integral part of these financial statements.

CONSOL ENERGY INC. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except per share data)

NOTE 1—BASIS OF PRESENTATION:
The accompanying Unaudited Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the three and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for future periods.
The balance sheet at December 31, 2011 has been derived from the Audited Consolidated Financial Statements at that date but does not include all the notes required by generally accepted accounting principles for complete financial statements. For further information, refer to the Consolidated Financial Statements and related notes for the year ended December 31, 2011 included in CONSOL Energy Inc.'s Form 10-K.
Basic earnings per share are computed by dividing net income by the weighted average shares outstanding during the reporting period. Dilutive earnings per share are computed similarly to basic earnings per share except that the weighted average shares outstanding are increased to include additional shares from the assumed exercise of stock options and performance stock options and the assumed vesting of restricted and performance share units, if dilutive. The number of additional shares is calculated by assuming that outstanding stock options and performance share options were exercised, that outstanding restricted stock units and performance share units were released, and that the proceeds from such activities were used to acquire shares of common stock at the average market price during the reporting period. CONSOL Energy Inc. (CONSOL Energy or the Company) includes the impact of pro forma deferred tax assets in determining potential windfalls and shortfalls for purposes of calculating assumed proceeds under the treasury stock method. The table below sets forth the share-based awards that have been excluded from the computation of the diluted earnings per share because their effect would be anti-dilutive:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Anti-Dilutive Options	2,421,923	987,471	2,418,983	1,005,303
Anti-Dilutive Restricted Stock Units	2,642	2,099	13,552	—
Anti-Dilutive Performance Share Units	91,340	—	91,340	—
Anti-Dilutive Performance Share Options	501,744	—	501,744	—
	3,017,649	989,570	3,025,619	1,005,303

The table below sets forth the share-based awards that have been exercised or released:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Options	39,418	58,353	51,134	238,749
Restricted Stock Units	64,589	63,228	522,607	404,369
Performance Share Units	—	—	229,730	40,752
	104,007	121,581	803,471	683,870

The weighted average exercise price per share of the options exercised during the three months ended June 30, 2012 and 2011 was $10.26 and $22.50, respectively. The weighted average exercise price per share of the options exercised during the six months ended June 30, 2012 and 2011 was $11.07 and $21.00, respectively.

The computations for basic and dilutive earnings per share are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net Income Attributable to CONSOL Energy Inc. Shareholders	$152,739	$77,384	$249,935	$269,533
Weighted average shares of common stock outstanding:				
Basic	227,548,394	226,647,752	227,408,832	226,499,994
Effect of stock-based compensation awards	1,703,791	2,490,272	1,713,762	2,417,341
Dilutive	229,252,185	229,138,024	229,122,594	228,917,335
Earnings per share:				
Basic	$0.67	$0.34	$1.10	$1.19
Dilutive	$0.67	$0.34	$1.09	$1.18

NOTE 2—ACQUISITIONS AND DISPOSITIONS:

On June 29, 2012, CONSOL Energy completed the disposition of its non-producing Northern Powder River Basin assets in southern Montana and northern Wyoming for cash proceeds of $169,500. The assets consisted of CONSOL Energy's 50% interest in Youngs Creek Mining Company LLC, CONSOL Energy's 50% interest in CX Ranch and related properties in and around Sheridan, Wyoming. The gain on the transaction was $150,677 and is included in Other Income in the Consolidated Statements of Income. Additionally, CONSOL Energy retained an 8% production royalty interest on approximately 200 million tons of permitted fee coal.

On April 4, 2012, CONSOL Energy completed the disposition of its non-producing Elk Creek property in southern West Virginia, which consisted of 20 thousand acres of coal lands and surface rights, for proceeds of $26,000. The gain on the transaction was $11,235 and is included in Other Income in the Consolidated Statements of Income.

On February 9, 2012, CONSOL Energy completed the disposition of its Burning Star No. 4 property in Illinois, which consisted of 4.3 thousand acres of coal lands and surface rights, for proceeds of $13,023. The gain on the transaction was $11,261 and is included in Other Income in the Consolidated Statements of Income.

On October 21, 2011, CNX Gas Company LLC (CNX Gas Company), a wholly owned subsidiary of CONSOL Energy, completed a sale to Hess Ohio Developments, LLC (Hess) of 50% of its nearly 200 thousand net Utica Shale acres in Ohio. Cash proceeds related to this transaction were $54,254, which are net of $5,719 transaction fees. Additionally, CONSOL Energy and Hess entered into a joint development agreement pursuant to which Hess agreed to pay approximately $534,000 in the form of a 50% drilling carry of certain CONSOL Energy working interest obligations as the acreage is developed. The aggregate amount of the drilling carry can be adjusted downward under provisions of the joint venture agreements in certain events. The net gain on the transaction was $53,095 and was recognized in the three months ended December 31, 2011.

On September 30, 2011, CNX Gas Company completed a sale to Noble Energy, Inc. (Noble) of 50% of the Company's undivided interest in certain Marcellus Shale oil and gas properties in West Virginia and Pennsylvania covering approximately 628 thousand net acres and 50% of the Company's undivided interest in certain of its existing Marcellus Shale wells and related leases. In September 2011, cash proceeds of $485,464 were received related to this transaction, which were net of $34,998 transaction fees. Additionally, a note receivable was recognized related to the two additional cash payments to be received on the first and second anniversary of the transaction closing date. The discounted notes receivable of $311,754 and $296,344 were recorded in Accounts and Notes Receivables—Notes Receivable and Other Assets—Notes Receivable, respectively. In the three months ended December 31, 2011, an

additional receivable of $16,703 and a payable of $980 were recorded for closing adjustments and were included in Accounts and Notes Receivable - Other and Accounts Payable, respectively. The net loss on the transaction was $64,142 and was recognized in the three months ended September 30, 2011. As part of the transaction, CNX Gas Company also received a commitment from Noble to pay one-third of the Company's working interest share of certain drilling and completion costs, up to approximately $2,100,000 with certain restrictions. These restrictions include the suspension of carry if average Henry Hub natural gas prices are below $4.00 per million British thermal units (MMBtu) for three consecutive months. The carry is currently suspended and will remain suspended until average natural gas prices are above $4.00/MMBtu for three consecutive months. Restrictions also include a $400,000 annual maximum on

Noble's carried cost obligation. The aggregate amount of the drilling carry may also be adjusted downward under provisions of the joint venture agreements in certain events.

The following unaudited pro forma combined financial statements are based on CONSOL Energy's historical consolidated financial statements and adjusted to give effect to the September 30, 2011 sale of a 50% interest in certain Marcellus Shale assets. The unaudited pro forma results for the period presented below are prepared as if the transaction occurred as of January 1, 2011 and do not include material, non-recurring charges.

	Three Months Ended June 30, 2011	Six Months Ended June 30, 2011
Total Revenue and Other Income	$1,573,910	$3,029,036
Earnings Before Income Taxes	$94,858	$342,276
Net Income	$74,359	$263,689
Basic Earnings Per Share	$0.33	$1.17
Dilutive Earnings Per Share	$0.32	$1.15

The pro forma results are not necessarily indicative of what actually would have occurred if the transaction with Noble had been completed as of January 1, 2011, nor are they necessarily indicative of future consolidated results.
On September 30, 2011, CNX Gas Company and Noble formed CONE Gathering LLC (CONE), a joint venture established to develop and operate each company's gas gathering system needs in the Marcellus Shale play. CNX Gas Company's 50% ownership interest in CONE is accounted for under the equity method of accounting. CNX Gas Company contributed its existing Marcellus Shale gathering infrastructure which had a net book value of $119,740 and Noble contributed cash of approximately $67,545. CONE made a cash distribution to CNX Gas Company in the amount of $67,545. The cash proceeds were recognized as cash inflows of $59,870 and $7,675 in Distributions from Equity Affiliates and Proceeds from the Sale of Assets, respectively, in CONSOL Energy's results of operations in the three months ended September 30, 2011. The gain on the transaction was $7,161 and was recognized in the three months ended September 30, 2011.

On September 21, 2011, CONSOL Energy entered into an agreement with Antero Resources Appalachian Corp. (Antero), pursuant to which CONSOL Energy assigned to Antero overriding royalty interests (ORRI) of approximately 7% in approximately 116 thousand net acres of Marcellus Shale located in nine counties in southwestern Pennsylvania and north central West Virginia, in exchange for $193,000. The net gain on the transaction was $41,057 and was recognized in the three months ended September 30, 2011.

NOTE 3—COMPONENTS OF PENSION AND OTHER POSTRETIREMENT BENEFIT (OPEB) PLANS NET PERIODIC BENEFIT COSTS:

Components of net periodic costs for the three and six months ended June 30 are as follows:

	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011	2012	2011	2012	2011
Service cost	$4,850	$4,440	$10,003	$8,729	$4,566	$2,862	$9,766	$6,839
Interest cost	9,415	9,794	18,793	18,872	32,795	47,665	68,322	89,869
Expected return on plan assets	(11,452)	(9,631)	(23,079)	(19,261)	—	—	—	—
Amortization of prior service cost (credits)	(407)	(166)	(815)	(333)	(13,410)	(11,600)	(25,009)	(23,199)
	11,654	9,905	23,917	19,051	20,020	30,318	40,365	52,682

Recognized net actuarial loss								
Net periodic benefit cost	$14,060	$14,342	$28,819	$27,058	$43,971	$69,245	$93,444	$126,191

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For the six months ended June 30, 2012, $67,292 was paid to the pension trust for pension benefits from operating cash flows. CONSOL Energy expects to contribute to the pension trust using prudent funding methods. Currently, depending on asset values and asset returns held in the trust, we expect to contribute $110,000 to the pension trust in 2012.

On March 31, 2012, the salaried OPEB plan was remeasured to reflect an announced plan amendment that will reduce medical and prescription drug benefits as of January 1, 2014. The plan amendment calls for a fixed annual retiree medical contribution into a Health Reimbursement Account for eligible employees. The amount of contribution is dependent on several factors. The money in the account can be used to help pay for a commercial medical plan, Medicare Part B or Part D premiums, and other qualified expenses. Employees who work or worked in corporate or operational support positions at retirement and who are age 50 or older at December 31, 2013 will receive the revised benefit in lieu of the current retiree medical and prescription drug benefits. Employees who work or worked in corporate or operational support positions who are under age 50 at December 31, 2013 will receive no retiree medical or prescription drug benefits. The remeasurement reflects the reduction in benefits and the change in discount rate to 4.57% at March 31, 2012 from 4.51% at December 31, 2011. The remeasurement resulted in an $80,570 reduction in the OPEB liability with a corresponding adjustment of $50,275 in other comprehensive income, net of $30,295 in deferred taxes. The change was made to align our corporate and operational support compensation package more closely with our peer group. The change resulted in a $3,142 reduction in OPEB expense compared to what was originally expected to be recognized for the three months ended June 30, 2012. Additionally, the change will result in a $6,283 reduction to OPEB expense compared to what was originally expected to be recognized for the remaining six months of 2012.

CONSOL Energy does not expect to contribute to the other postemployment benefit plan in 2012. We intend to pay benefit claims as they become due. For the six months ended June 30, 2012, $83,353 of other postemployment benefits have been paid.
For the six months ended June 30, 2011, CONSOL Energy received proceeds of $7,781 under the Patient Protection and Affordable Care Act (PPACA) related to reimbursement from the Federal government for retiree health spending. This amount was included as a reduction of benefit and other payments in the reconciliation of changes in benefit obligation. No additional proceeds will be received under this program.

NOTE 4—COMPONENTS OF COAL WORKERS' PNEUMOCONIOSIS (CWP) AND WORKERS' COMPENSATION NET PERIODIC BENEFIT COSTS:
Components of net periodic costs (benefits) for the three and six months ended June 30 are as follows:

	CWP				Workers' Compensation			
	Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended	
	June 30,		June 30,		June 30,		June 30,	
	2012	2011	2012	2011	2012	2011	2012	2011
Service cost	$1,178	$1,155	$2,356	$2,310	$3,634	$4,468	$7,268	$8,936
Interest cost	1,991	2,332	3,982	4,665	1,778	2,059	3,556	4,119
Amortization of actuarial gain	(4,933)	(5,477)	(9,867)	(10,955)	(986)	(976)	(1,972)	(1,953)
State administrative fees and insurance bond premiums	—	—	—	—	1,635	1,986	3,545	3,208
Legal and administrative costs	750	750	1,500	1,500	648	719	1,296	1,437
Net periodic (benefit) cost	$(1,014)	$(1,240)	$(2,029)	$(2,480)	$6,709	$8,256	$13,693	$15,747

CONSOL Energy does not expect to contribute to the CWP plan in 2012. We intend to pay benefit claims as they become due. For the six months ended June 30, 2012, $5,654 of CWP benefit claims have been paid.

CONSOL Energy does not expect to contribute to the workers' compensation plan in 2012. We intend to pay benefit claims as they become due. For the six months ended June 30, 2012, $16,018 of workers' compensation benefits, state administrative fees and surety bond premiums have been paid.

NOTE 5—INCOME TAXES:

The following is a reconciliation, stated in dollars and as a percentage of pretax income, of the U.S. statutory federal income tax rate to CONSOL Energy's effective tax rate:

	For the Six Months Ended June 30,			
	2012		2011	
	Amount	Percent	Amount	Percent
Statutory U.S. federal income tax rate	$115,591	35.0 %	$122,451	35.0 %
Excess tax depletion	(39,275)	(11.9)	(52,839)	(15.1)
Effect of domestic production activities	(251)	(0.1)	(5,131)	(1.5)
Net effect of state income taxes	5,831	1.8	11,906	3.4
Other	(1,570)	(0.5)	3,941	1.2
Income Tax Expense / Effective Rate	$80,326	24.3 %	$80,328	23.0 %

The effective rates for the six months ended June 30, 2012 and 2011 were calculated using the annual effective rate projection on recurring earnings and include tax liabilities related to certain discrete transactions which are described below.

In the three months ended June 30, 2012, CONSOL Energy disposed of non-producing Northern Powder River Basin assets. The Company recognized a gain of $150,677 on the disposition. CONSOL Energy recorded $48,643 in federal and state income taxes related to the sale.

During the six months ended June 30, 2012, CONSOL Energy reached an agreement with the Internal Revenue Service Appeals Division on its Extraterritorial Income Exclusion refund claim for tax years 2004-2005. As a result of the agreement, the Company reflected $983 as a discrete reduction to income tax expense. The discrete transaction was reflected in the Other line of the rate reconciliation.

The total amounts of uncertain tax positions at June 30, 2012 and 2011 were $25,570 and $65,510, respectively. If these uncertain tax positions were recognized, approximately $3,891 and $16,802, respectively, would affect CONSOL Energy's effective tax rate. There were no additions to the liability for unrecognized tax benefits during the six months ended June 30, 2012 and 2011.

CONSOL Energy recognizes interest accrued related to uncertain tax positions in its interest expense. As of June 30, 2012 and 2011, the Company reported an accrued interest liability relating to uncertain tax positions of $6,429 and $13,043, respectively. The accrued interest liability includes $1,055 of interest income and $2,269 of interest expense that is reflected in the Company's Consolidated Statements of Income for the six months ended June 30, 2012 and 2011, respectively.

CONSOL Energy recognizes penalties accrued related to uncertain tax positions in its income tax expense. As of June 30, 2012 and 2011, CONSOL Energy had no accrued liability for tax penalties.

CONSOL Energy and its subsidiaries file federal income tax returns with the United States and returns within various states and Canadian jurisdictions. With few exceptions, the Company is no longer subject to United States federal, state, local, or non-U.S. income tax determinations by tax authorities for the years before 2008.

NOTE 6—INVENTORIES:

Inventory components consist of the following:

	June 30, 2012	December 31, 2011
Coal	$135,800	$105,378

Merchandise for resale	38,761	43,639
Supplies	130,500	109,318
Total Inventories	$305,061	$258,335

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Merchandise for resale is valued using the last-in, first-out (LIFO) cost method. The excess of replacement cost of merchandise for resale inventories over carrying LIFO value was $21,802 and $22,406 at June 30, 2012 and December 31, 2011, respectively.

NOTE 7—ACCOUNTS RECEIVABLE SECURITIZATION:

CONSOL Energy and certain of our U.S. subsidiaries are party to a trade accounts receivable facility with financial institutions for the sale on a continuous basis of eligible trade accounts receivable. The facility allows CONSOL Energy to receive on a revolving basis up to $200,000. The facility also allows for the issuance of letters of credit against the $200,000 capacity. At June 30, 2012, there were letters of credit outstanding against the facility of $160,779. CONSOL Energy management believes that these guarantees will expire without being funded, and therefore the commitments will not have a material adverse effect on the Company's financial condition. No amounts related to these financial guarantees and letters of credit are recorded as liabilities on the financial statements.

CNX Funding Corporation, a wholly owned, special purpose, bankruptcy-remote subsidiary, buys and sells eligible trade receivables generated by certain subsidiaries of CONSOL Energy. Under the receivables facility, CONSOL Energy and certain subsidiaries, irrevocably and without recourse, sell all of their eligible trade accounts receivable to CNX Funding Corporation, who in turn sells these receivables to financial institutions and their affiliates, while maintaining a subordinated interest in a portion of the pool of trade receivables. This retained interest, which is included in Accounts and Notes Receivable Trade in the Consolidated Balance Sheets, is recorded at fair value. Due to a short average collection cycle for such receivables, our collection experience history and the composition of the designated pool of trade accounts receivable that are part of this program, the fair value of our retained interest approximates the total amount of the designated pool of accounts receivable. CONSOL Energy will continue to service the sold trade receivables for the financial institutions for a fee based upon market rates for similar services.

In accordance with the Transfers and Servicing Topics of the Financial Accounting Standards Board (FASB) Accounting Standards Codification, CONSOL Energy records transactions under the securitization facility as secured borrowings on the Consolidated Balance Sheets. The pledge of collateral is reported as Accounts Receivable - Securitized and the borrowings are classified as debt in Borrowings under Securitization Facility.

The cost of funds under this facility is based upon commercial paper rates, plus a charge for administrative services paid to the financial institutions. Costs associated with the receivables facility totaled $437 and $856 for three and six months ended June 30, 2012, respectively. Costs associated with the receivables facility totaled $572 and $1,297 for three and six months ended June 30, 2011, respectively. These costs have been recorded as financing fees which are included in Cost of Goods Sold and Other Operating Charges in the Consolidated Statements of Income. No servicing asset or liability has been recorded. The receivables facility expires in March 2017 with the underlying liquidity agreement renewing annually each March.

At June 30, 2012 and December 31, 2011, eligible accounts receivable totaled $179,700 and $192,700, respectively. There was subordinated retained interest of $18,921 at June 30, 2012 and $192,700 at December 31, 2011. There were no borrowings under the Securitization Facility recorded on the Consolidated Balance Sheet as of June 30, 2012 and December 31, 2011. However, there were letters of credit of $160,779 outstanding against the facility at June 30, 2012. The accounts receivable securitization program decreased by $130,000 in the six months ended June 30, 2011. The decrease is reflected in the Net Cash Used in Financing Activities in the Consolidated Statement of Cash Flows. In accordance with the facility agreement, the Company is able to receive proceeds based upon the eligible accounts receivable at the previous month end.

NOTE 8—PROPERTY, PLANT AND EQUIPMENT:

	June 30, 2012	December 31, 2011
Coal and other plant and equipment	$5,533,114	$5,160,759
Proven gas properties	1,542,842	1,542,837
Intangible drilling cost	1,446,650	1,277,678
Coal properties and surface lands	1,333,362	1,340,757
Unproven gas properties	1,270,758	1,258,027
Gas gathering equipment	988,337	963,494
Airshafts	678,234	659,736
Leased coal lands	540,516	540,817
Mine development	495,607	457,179
Gas wells and related equipment	419,409	408,814
Coal advance mining royalties	398,781	393,340
Other gas assets	81,934	79,816
Gas advance royalties	6,795	4,065
Total Property Plant and Equipment	14,736,339	14,087,319
Less: Accumulated DD&A	5,065,462	4,760,903
Total Net PP&E	$9,670,877	$9,326,416

Industry Participation Agreements

As of June 30, 2012, CONSOL Energy had entered into two significant industry participation agreements (referred to as "joint ventures" or "JVs") that provided drilling and completion carries for our retained interests. The following table provides information about our industry participation agreements as of June 30, 2012:

Shale Play	Industry Participation Agreement Partner	Industry Participation Agreement Date	Total Drilling Carries	Drilling Carries Billed to Partner	Drilling Carries Remaining
Marcellus	Noble Energy, Inc.	September 30, 2011	$2,100,000	$10,204	$2,089,796
Utica	Hess Ohio Developments, LLC	October 21, 2011	$534,000	$6,366	$527,634

NOTE 9—SHORT-TERM NOTES PAYABLE:

CONSOL Energy's $1,500,000 Senior Secured Credit Agreement expires April 12, 2016. The facility is secured by substantially all of the assets of CONSOL Energy and certain of its subsidiaries. CONSOL Energy's credit facility allows for up to $1,500,000 of borrowings and letters of credit. CONSOL Energy can request an additional $250,000 increase in the aggregate borrowing limit amount. Fees and interest rate spreads are based on a ratio of financial covenant debt to twelve-month trailing earnings before interest, taxes, depreciation, depletion and amortization (EBITDA), measured quarterly. The facility includes a minimum interest coverage ratio covenant of no less than 2.50 to 1.00, measured quarterly. The interest coverage ratio was 6.29 to 1.00 at June 30, 2012. The facility includes a maximum leverage ratio covenant of not more than 4.75 to 1.00, measured quarterly through March 31, 2013, and no more than 4.50 to 1.00 thereafter. The leverage ratio was 1.92 to 1.00 at June 30, 2012. The facility also includes a senior secured leverage ratio covenant of not more than 2.00 to 1.00, measured quarterly. The senior secured leverage ratio was 0.07 to 1.00 at June 30, 2012. Affirmative and negative covenants in the facility limit our ability to dispose of assets, make investments, purchase or redeem CONSOL Energy common stock, pay dividends, merge with another corporation and amend, modify or restate the senior unsecured notes. At June 30, 2012, the $1,500,000 facility had no borrowings outstanding and $100,088 of letters of credit outstanding, leaving $1,399,912 of capacity available for borrowings and the issuance of letters of credit. The facility had no borrowings outstanding at December 31, 2011.

CNX Gas Corporation's (CNX Gas) $1,000,000 Senior Secured Credit Agreement expires April 12, 2016. The facility is secured by substantially all of the assets of CNX Gas and its subsidiaries. CNX Gas' credit facility allows for up to

$1,000,000

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for borrowings and letters of credit. CNX Gas can request an additional $250,000 increase in the aggregate borrowing limit amount. Fees and interest rate spreads are based on the percentage of facility utilization, measured quarterly. Covenants in the facility limit CNX Gas' ability to dispose of assets, make investments, pay dividends and merge with another corporation. The credit facility allows investments in joint ventures for the development and operation of gas gathering systems and provides for $600,000 of loans, advances and dividends from CNX Gas to CONSOL Energy. Investments in the CONE are unrestricted. The facility includes a maximum leverage ratio covenant of not more than 3.50 to 1.00, measured quarterly. The leverage ratio was 0.46 to 1.00 at June 30, 2012. The facility also includes a minimum interest coverage ratio covenant of no less than 3.00 to 1.00, measured quarterly. This ratio was 35.17 to 1.00 at June 30, 2012. At June 30, 2012, the $1,000,000 facility had no borrowings outstanding and $70,203 of letters of credit outstanding, leaving $929,797 of capacity available for borrowings and the issuance of letters of credit. The facility had no borrowings outstanding at December 31, 2011. The average interest rate for the three months and six months ended June 30, 2012 was 2.12%. Accrued interest of $9 is included in Other Accrued Liabilities in the Consolidated Balance Sheet at June 30, 2012. There was no accrued interest at December 31, 2011.

NOTE 10—LONG-TERM DEBT:

	June 30, 2012	December 31, 2011
Debt:		
Senior notes due April 2017 at 8.00%, issued at par value	$1,500,000	$1,500,000
Senior notes due April 2020 at 8.25%, issued at par value	1,250,000	1,250,000
Senior notes due March 2021 at 6.375%, issued at par value	250,000	250,000
Baltimore Port Facility revenue bonds in series due September 2025 at 5.75%	102,865	102,865
Advance royalty commitments (6.73% weighted average interest rate for June 30, 2012 and December 31, 2011, respectively)	31,053	31,053
Other long-term note maturing in 2031	75	75
	3,133,993	3,133,993
Less amounts due in one year	11,759	11,759
Long-Term Debt	$3,122,234	$3,122,234

Accrued interest related to Long-Term Debt of $63,262 and $63,259 was included in Other Accrued Liabilities in the Consolidated Balance Sheets at June 30, 2012 and December 31, 2011, respectively.

NOTE 11—COMMITMENTS AND CONTINGENCIES:

CONSOL Energy and its subsidiaries are subject to various lawsuits and claims with respect to such matters as personal injury, wrongful death, damage to property, exposure to hazardous substances, governmental regulations including environmental remediation, employment and contract disputes and other claims and actions arising out of the normal course of business. We accrue the estimated loss for these lawsuits and claims when the loss is probable and can be estimated. Our current estimated accruals related to these pending claims, individually and in the aggregate, are immaterial to the financial position, results of operations or cash flows of CONSOL Energy. It is possible that the aggregate loss in the future with respect to these lawsuits and claims could ultimately be material to the financial position, results of operations or cash flows of CONSOL Energy; however, such amounts cannot be reasonably estimated. The amount claimed against CONSOL Energy is disclosed below when an amount is expressly stated in the lawsuit or claim, which is not often the case. The maximum aggregate amount claimed in those lawsuits and claims, regardless of probability, where a claim is expressly stated or can be estimated, exceeds the aggregate amounts accrued for all lawsuits and claims by approximately $1,099,260.

The following lawsuits and claims include those for which a loss is probable and an accrual has been recognized.

American Electric Corp: On August 8, 2011, the United States Environmental Protection Agency, Region IV, sent Consolidation Coal Company a General Notice and Offer to Negotiate regarding the Ellis Road/American Electric Corp. Superfund Site in Jacksonville, Florida. The General Notice was sent to approximately 180 former customers of American Electric Corp. CONSOL Energy has confirmed that it did business with American Electric Corp. in 1983 and 1984. The General Notice indicated that the Environmental Protection Agency (EPA) has determined that polychlorinated biphenyls (PCBs) and other contaminants in the soils and sediments at and near the site require a removal action. The Offer to Negotiate invited the potentially responsible parties (PRPs) to enter into an Administrative Settlement Agreement and Order on Consent

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(AOC) to provide for conducting the removal action under the EPA oversight and to reimburse the EPA for its past costs, in the amount of $384 and for its future costs. CONSOL Energy responded to the EPA indicating its willingness to participate in such negotiations, and CONSOL Energy is participating in a group of potentially responsible parties to conduct the removal action. The AOC was signed July 20, 2012, and as a result, the EPA granted the performing parties a $408 orphan share credit, which will offset the EPA's past costs. The actual scope of the work has yet to be determined, but the current estimate of the total costs of the removal action is in the range of $2,000 to $5,400, with CONSOL Energy's share of such costs at approximately 8%. CONSOL Energy has established an initial accrual based on its allocated share of the costs among the viable former customers of American Electric Corp. The liability is immaterial to the overall financial position of CONSOL Energy and is included in Other Accrued Liabilities on the Consolidated Balance Sheet.

Ward Transformer Superfund Site: CONSOL Energy was notified in November 2004 by the EPA that it is a potentially responsible party (PRP) under the Superfund program established by the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), with respect to the Ward Transformer site in Wake County, North Carolina. The EPA, CONSOL Energy and two other PRPs entered into an administrative Settlement Agreement and Order on Consent, requiring those PRPs to undertake and complete a PCB soil removal action, at and in the vicinity of the Ward Transformer property. In June 2008, while conducting the PCB soil excavation on the Ward property, it was determined that PCBs have migrated onto adjacent properties and in September 2008, the EPA notified CONSOL Energy and 60 other companies that they are PRPs for these additional areas. The current estimated cost of remedial action for the area CONSOL Energy was originally named a PRP, including payment of the EPA's past and future cost, is approximately $65,000. The current estimated cost of the most likely remediation plan for the additional areas discovered is approximately $11,000. CONSOL Energy recognized no expense in Cost of Goods Sold and Other charges in the three and six months ended June 30, 2012 and 2011, respectively. CONSOL Energy funded $250 in the six months ended June 30, 2011 to an independent trust established for this remediation. No contributions were made to the trust in the six months ended June 30, 2012. As of June 30, 2012, CONSOL Energy and the other participating PRPs had asserted CERCLA cost recovery and contribution claims against approximately 225 nonparticipating PRPs to recover a share of the costs incurred and to be incurred to conduct the removal actions at the Ward Site. CONSOL Energy's portion of recoveries from settled claims is $4,488. Accordingly, the liability reflected in Other Accrued Liabilities was reduced by these settled claims. The remaining net liability at June 30, 2012 is $3,472.

Asbestos-Related Litigation: One of our subsidiaries, Fairmont Supply Company (Fairmont), which distributes industrial supplies, currently is named as a defendant in approximately 6,900 asbestos-related claims in state courts in Pennsylvania, Ohio, West Virginia, Maryland, Texas and Illinois. Because a very small percentage of products manufactured by third parties and supplied by Fairmont in the past may have contained asbestos and many of the pending claims are part of mass complaints filed by hundreds of plaintiffs against a hundred or more defendants, it has been difficult for Fairmont to determine how many of the cases actually involve valid claims or plaintiffs who were actually exposed to asbestos-containing products supplied by Fairmont. In addition, while Fairmont may be entitled to indemnity or contribution in certain jurisdictions from manufacturers of identified products, the availability of such indemnity or contribution is unclear at this time, and in recent years, some of the manufacturers named as defendants in these actions have sought protection from these claims under bankruptcy laws. Fairmont has no insurance coverage with respect to these asbestos cases. Based on over 15 years of experience with this litigation, we have established an accrual to cover our estimated liability for these cases. This accrual is immaterial to the overall financial position of CONSOL Energy and is included in Other Accrued Liabilities on the Consolidated Balance Sheet. Past payments by Fairmont with respect to asbestos cases have not been material.

Ryerson Dam Litigation: In 2008, the Pennsylvania Department of Conservation and Natural Resources (the Commonwealth) filed a six-count Complaint in the Court of Common Pleas of Allegheny County, Pennsylvania, claiming that the Company's underground longwall mining activities at its Bailey Mine caused cracks and seepage damage to the Ryerson Park Dam. The Commonwealth subsequently breached the dam, thereby eliminating the

Ryerson Park Lake. The Commonwealth claimed that the Company is liable for dam reconstruction costs, lake restoration costs and natural resource damages totaling $58,000. In October 2008, the Common Pleas Court ruled that natural resource damages were not recoverable and referred the Commonwealth's claim to the Pennsylvania Department of Environmental Protection (DEP). On February 16, 2010, the DEP issued an interim report, concluding that the alleged damage was subsidence related. The DEP estimated the cost of repair to be approximately $20,000. The Company has appealed the DEP's findings to the Pennsylvania Environmental Hearing Board (PEHB), which will consider the case de novo, meaning without regard to the DEP's decision, as to any finding of causation of damage and/or the amount of damages. Either party may appeal the decision of the PEHB to the Pennsylvania Commonwealth Court, and then, as may be allowed, to the Pennsylvania Supreme Court. A hearing on the merits of the case will not occur until sometime in the spring or summer of 2013. As to the underlying claim, CONSOL Energy believes it is not responsible for the damage to the dam and that numerous grounds exist upon which to challenge the propriety of the claims. If CONSOL Energy is ultimately found to be liable for damages to the dam, we believe the range of loss would be between $9,000 and $30,000. There have been settlement discussions and we have established an accrual to cover our estimated

settlement liability for this case. This accrual is immaterial to the overall financial position of CONSOL Energy and is included in Other Accrued Liabilities on the Consolidated Balance Sheet.

C. L. Ritter: On March 1, 2011, the Company was served with a complaint instituted by C. L. Ritter Lumber Company Incorporated against Consolidation Coal Company (CCC), Island Creek Coal Company, (ICCC), CNX Gas Company, subsidiaries of CONSOL Energy Inc., as well as CONSOL Energy itself in the Circuit Court of Buchanan County, Virginia, seeking damages and injunctive relief in connection with the deposit of untreated water from mining activities at CCC's Buchanan Mine into nearby void spaces at one of the mines of ICCC. The suit alleged damages of between $34,000 and $430,000 for alleged damage to coal and coalbed methane, as well as breach of contract damages. We removed the case to federal court and filed a motion to dismiss, largely predicated on the statute of limitations bar. The trial judge ruled that the issue of the applicability of the statute of limitations bar can only be addressed after discovery. The case has settled for an amount which is immaterial to the overall financial position of CONSOL Energy and has been dismissed with prejudice.

Hale Litigation: A purported class action lawsuit was filed on September 23, 2010 in U.S. District Court in Abingdon, Virginia styled Hale v. CNX Gas Company, et. al. The lawsuit alleges that the plaintiff class consists of oil and gas owners, that the Virginia Supreme Court has decided that coalbed methane (CBM) belongs to the owner of the oil and gas estate, that the Virginia Gas and Oil Act of 1990 unconstitutionally allows force pooling of CBM, that the Act unconstitutionally provides only a 1/8 royalty to CBM owners for gas produced under the force pooling orders, and that the Company only relied upon control of the coal estate in force pooling the CBM notwithstanding the Virginia Supreme Court decision holding that if only the coal estate is controlled, the CBM is not thereby controlled. The lawsuit seeks a judicial declaration of ownership of the CBM and that the entire net proceeds of CBM production (that is, the 1/8 royalty and the 7/8 of net revenues since production began) be distributed to the class members. The Magistrate Judge issued a Report and Recommendation in which she recommended that the District Judge decide that the deemed lease provision of the Gas and Oil Act is constitutional as is the 1/8 royalty, and that CNX Gas need not distribute the net proceeds to class members. The Magistrate Judge recommended against the dismissal of certain other claims, none of which are believed to have any significance. The District Judge affirmed the Magistrate Judge's recommendations in their entirety. Discovery is proceeding in this litigation. CONSOL Energy believes that the case is without merit and intends to defend it vigorously. We have established an accrual to cover our estimated liability for this case. This accrual is immaterial to the overall financial position of CONSOL Energy and is included in Other Accrued Liabilities on the Consolidated Balance Sheet.
Addison Litigation: A purported class action lawsuit was filed on April 28, 2010 in Federal court in Virginia styled Addison v. CNX Gas Company. The case involves two primary claims: (i) the plaintiff and similarly situated CNX Gas Company lessors identified as conflicting claimants during the force pooling process before the Virginia Gas and Oil Board are the owners of the CBM and, accordingly, the owners of the escrowed royalty payments being held by the Commonwealth of Virginia; and (ii) CNX Gas Company failed to either pay royalties due these conflicting claimant lessors or paid them less than required because of the alleged practice of improper below market sales and/or taking alleged improper post-production deductions. Plaintiffs seek a declaratory judgment regarding ownership and compensatory and punitive damages for breach of contract; conversion; negligence (voluntary undertaking), for force pooling coal owners after the Ratliff decision declared coal owners did not own the CBM; negligent breach of duties as an operator; breach of fiduciary duties; and unjust enrichment. We filed a Motion to Dismiss in this case, and the Magistrate Judge recommended dismissing some claims and allowing others to proceed. The District Judge affirmed the Magistrate Judge's recommendations in their entirety. Discovery is proceeding in this litigation. CONSOL Energy believes that the case is without merit and intends to defend it vigorously. We have established an accrual to cover our estimated liability for this case. This accrual is immaterial to the overall financial position of CONSOL Energy and is included in Other Accrued Liabilities on the Consolidated Balance Sheet.
South Carolina Gas & Electric Company Arbitration: South Carolina Electric & Gas Company (SCE&G), a utility, has demanded arbitration, seeking $36,000 in damages against CONSOL of Kentucky and CONSOL Energy Sales Company, both wholly owned subsidiaries of CONSOL Energy. SCE&G claims it suffered damages in obtaining

cover coal to replace coal which was not delivered in 2008 under a coal sales agreement. CONSOL Energy counterclaimed against SCE&G for $9,400 for terminating coal shipments under the sales agreement which SCE&G had agreed could be made up in 2009. A hearing on the claims commenced on April 30, 2012. Initial briefs have been filed, with reply briefs to follow. A decision will likely be rendered within sixty days following those briefs and oral argument. The named CONSOL Energy defendants deny all liability and intend to vigorously defend the action filed against them. Notwithstanding that fact, we have established an accrual to cover our estimated liability for this case. This accrual is immaterial to the overall financial position of CONSOL Energy and is included in Other Accrued Liabilities on the Consolidated Balance Sheet. If liability is ultimately imposed on the named CONSOL Energy defendants, we believe the range of loss would be between $1,000 and $29,000.
The following lawsuits and claims include those for which a loss is reasonably possible, but not probable, and accordingly no accrual has been recognized.

CNX Gas Shareholders Litigation: CONSOL Energy has been named as a defendant in five putative class actions brought by alleged shareholders of CNX Gas challenging the tender offer by CONSOL Energy to acquire all of the shares of CNX Gas common stock that CONSOL Energy did not already own for $38.25 per share. The two cases filed in Pennsylvania Common Pleas Court have been stayed and the three cases filed in the Delaware Chancery Court have been consolidated under the caption In Re CNX Gas Shareholders Litigation (C.A. No. 5377-VCL). All five actions generally allege that CONSOL Energy breached and/or aided and abetted in the breach of fiduciary duties purportedly owed to CNX Gas public shareholders, essentially alleging that the $38.25 per share price that CONSOL Energy paid to CNX Gas shareholders in the tender offer and subsequent short-form merger was unfair. Among other things, the actions sought a permanent injunction against or rescission of the tender offer, damages, and attorneys' fees and expenses. The lawsuit will likely go to trial, probably in 2013. CONSOL Energy believes that these actions are without merit and intends to defend them vigorously. For that reason, we have not accrued a liability for this claim; however, if liability is ultimately imposed, based on the expert reports that have been exchanged by the parties, we believe the potential loss could be up to $221,000.

The following royalty and land right lawsuits and claims include those for which a loss is reasonably possible, but not probable, and accordingly, no accrual has been recognized. These claims are influenced by many factors which prevent the estimation of a range of potential loss. These factors include, but are not limited to, generalized allegations of unspecified damages (such as improper deductions), discovery having not commenced or not having been completed, unavailability of expert reports on damages and non-monetary issues are being tried. For example, in instances where a gas lease termination is sought, damages would depend on speculation as to if and when the gas production would otherwise have occurred, how many wells would have been drilled on the lease premises, what their production would be, what the cost of production would be, and what the price of gas would be during the production period. An estimate is calculated, if applicable, when sufficient information becomes available.

Ratliff: On March 22, 2012, the Company was served with four complaints filed on May 31, 2011 which were instituted by four individuals against CCC, ICCC, CNX Gas Company, subsidiaries of CONSOL Energy, as well as CONSOL Energy itself in the Circuit Court of Russell County, Virginia, seeking damages and injunctive relief in connection with the deposit of untreated water from mining activities at CCC's Buchanan Mine into nearby void spaces at some of the mines of ICCC. The suits each allege damages of between $25,750 and $119,500 for alleged damage to coal and coalbed methane, as well as breach of contract and assumpsit damages. We have removed the cases to federal court and filed a motion to dismiss, largely predicated on the statute of limitations bar. Three similar lawsuits were filed recently, one in federal court and two in the Circuit Court of Buchanan County, Virginia, by other plaintiffs that collectively allege damages of between $100,000 and $622,000. One of the three suits which claimed damages of $22,000 was dismissed in federal court and has been appealed. Another which claimed damages of $312,000 was settled for an amount immaterial to the overall financial position of CONSOL Energy. The Company removed the third case to federal court and filed a motion to dismiss the case. CCC believes that it had, and continues to have, the right to store water in these void areas. CCC and the other named CONSOL Energy defendants deny all liability and intend to vigorously defend the actions filed against them in connection with the removal and deposit of water from the Buchanan Mine. Consequently, we have not recognized any liability related to these actions.

Hall Litigation: A purported class action lawsuit was filed on December 23, 2010 styled Hall v. CONSOL Gas Company in Allegheny County Pennsylvania Common Pleas Court. The named plaintiff is Earl D. Hall. The purported class plaintiffs are all Pennsylvania oil and gas lessors to Dominion Exploration and Production Company, whose leases were acquired by CONSOL Energy. The complaint alleges more than 1,000 similarly situated lessors. The lawsuit alleges that CONSOL Energy incorrectly calculated royalties by (i) calculating line loss on the basis of allocated volumes rather than on a well-by-well basis, (ii) possibly calculating the royalty on the basis of an incorrect price, (iii) possibly taking unreasonable deductions for post-production costs and costs that were not arms-length, (iv) not paying royalties on gas lost or used before the point of sale, and (v) not paying royalties on oil production. The complaint also alleges that royalty statements were false and misleading. The complaint seeks damages, interest and

an accounting on a well-by-well basis. CONSOL Energy believes that the case is without merit and intends to defend it vigorously. Consequently, we have not recognized any liability related to these actions.

Kennedy Litigation: The Company is a party to a case filed on March 26, 2008 captioned Earl Kennedy (and others) v. CNX Gas Company and CONSOL Energy in the Court of Common Pleas of Greene County, Pennsylvania. The lawsuit alleges that CNX Gas Company and CONSOL Energy trespassed and converted gas and other minerals allegedly belonging to the plaintiffs in connection with wells drilled by CNX Gas Company. The complaint, as amended, seeks injunctive relief, including removing CNX Gas Company from the property, and compensatory damages of $20,000. The suit also sought to overturn existing law as to the ownership of coalbed methane in Pennsylvania, but that claim was dismissed by the court; the plaintiffs are seeking to appeal that dismissal. The suit also seeks a determination that the Pittsburgh 8 coal seam does not include the “roof/rider” coal. The court denied the plaintiff's summary judgment motion on that issue. The court held a bench trial on the “roof/rider” coal issue in November 2011 and we are awaiting a decision. CNX Gas Company and CONSOL

Energy believe this lawsuit to be without merit and intend to vigorously defend it. Consequently, we have not recognized any liability related to these actions.

Rowland Litigation: Rowland Land Company filed a complaint in May 2011 against CONSOL Energy, CNX Gas Company, Dominion Resources, and EQT Production Company (EQT) in Raleigh County Circuit Court, West Virginia. Rowland is the lessor on a 33,000 acre oil and gas lease in southern West Virginia. EQT was the original lessee, but they farmed out the development of the lease to Dominion Resources, in exchange for an overriding royalty. Dominion Resources sold the indirect subsidiary that held the lease to a subsidiary of CONSOL Energy on April 30, 2010. Subsequent to that acquisition, the subsidiary that held the lease was merged into CNX Gas Company as part of an internal reorganization. Rowland alleges that (i) Dominion Resources' sale of the subsidiary to CONSOL Energy was a change in control that required its consent under the terms of the farmout agreement and lease, and (ii) the subsequent merger of the subsidiary into CNX Gas Company was an assignment that required its consent under the lease. Rowland amended its complaint to include allegations that CONSOL Energy and Dominion Resources are liable for their subsidiaries' actions. CONSOL Energy and CNX Gas Company filed a motion to dismiss the complaint which was denied. Discovery is proceeding. CONSOL Energy believes that the case is without merit and intends to defend it vigorously. Consequently, we have not recognized any liability related to these actions.

Majorsville Storage Field Declaratory Judgment: On March 3, 2011, an attorney sent a letter to CNX Gas Company regarding certain leases that CNX Gas Company obtained from Columbia Gas in Greene County, Pennsylvania involving the Majorsville Storage Field. The letter was written on behalf of three lessors alleging that the leases totaling 525 acres are invalid, and had expired by their terms. The plaintiffs' theory is that the rights of storage and production are severable under the leases. Ignoring the fact that the leases have been used for gas storage, they claim that since there has been no production or development of production, the right to produce gas expired at the end of the primary terms. On June 16, 2011 in the Court of Common Pleas of Greene County, Pennsylvania, the Company filed a declaratory judgment action, seeking to have a court confirm the validity of the leases. We believe that we will prevail in this litigation based on the language of the leases and the current status of the law. Consequently, we have not recognized any liability related to these actions.

The following lawsuit and claims include those for which a loss is remote and accordingly, no accrual has been recognized, although if a non-favorable verdict were received the impact could be material.

Comer Litigation: In 2005, plaintiffs Ned Comer and others filed a purported class action lawsuit in the U.S. District Court for the Southern District of Mississippi against a number of companies in energy, fossil fuels and chemical industries, including CONSOL Energy styled, Comer, et al. v. Murphy Oil, et al. The plaintiffs, residents and owners of property along the Mississippi Gulf coast, alleged that the defendants caused the emission of greenhouse gases that contributed to global warming, which in turn caused a rise in sea levels and added to the ferocity of Hurricane Katrina, which combined to destroy the plaintiffs' property. The District Court dismissed the case and the plaintiffs appealed. The Circuit Court panel reversed and the defendants sought a rehearing before the entire court. A rehearing before the entire court was granted, which had the effect of vacating the panel's reversal, but before the case could be heard on the merits, a number of judges recused themselves and there was no longer a quorum. As a result, the District Court's dismissal was effectively reinstated. The plaintiffs asked the U.S. Supreme Court to require the Circuit Court to address the merits of their appeal. On January 11, 2011, the Supreme Court denied that request. Although that should have resulted in the dismissal being final, the plaintiffs filed a lawsuit on May 27, 2011, in the same jurisdiction against essentially the same defendants making nearly identical allegations as in the original lawsuit. The trial court has dismissed this case. The dismissal is being appealed.

At June 30, 2012, CONSOL Energy has provided the following financial guarantees, unconditional purchase obligations and letters of credit to certain third parties, as described by major category in the following table. These amounts represent the maximum potential total of future payments that we could be required to make under these instruments. These amounts have not been reduced for potential recoveries under recourse or collateralization provisions. Generally, recoveries under reclamation bonds would be limited to the extent of the work performed at the time of the default. No amounts related to these financial guarantees and letters of credit are recorded as liabilities on the financial statements. CONSOL Energy management believes that these guarantees will expire without being

funded, and therefore the commitments will not have a material adverse effect on financial condition.

	Amount of Commitment Expiration Per Period				
	Total Amounts Committed	Less Than 1 Year	1-3 Years	3-5 Years	Beyond 5 Years
Letters of Credit:					
Employee-Related	$193,641	$127,158	$66,483	$—	$—
Environmental	56,994	55,266	1,728	—	—
Other	80,508	28,717	51,791	—	—
Total Letters of Credit	331,143	211,141	120,002	—	—
Surety Bonds:					
Employee-Related	204,884	193,384	11,500	—	—
Environmental	453,668	444,560	9,108	—	—
Other	28,626	28,614	11	—	1
Total Surety Bonds	687,178	666,558	20,619	—	1
Guarantees:					
Coal	15,931	9,863	1,068	1,000	4,000
Gas	113,513	62,906	19,985	—	30,622
Other	457,169	86,289	141,638	85,476	143,766
Total Guarantees	586,613	159,058	162,691	86,476	178,388
Total Commitments	$1,604,934	$1,036,757	$303,312	$86,476	$178,389

Employee-related financial guarantees have primarily been provided to support the United Mine Workers' of America's 1992 Benefit Plan and various state and federal workers' compensation self-insurance programs. Environmental financial guarantees have primarily been provided to support various performance bonds related to reclamation and other environmental issues. Coal and Gas financial guarantees have primarily been provided to support various sales contracts. Other guarantees have also been extended to support insurance policies, legal matters, full and timely payments of mining equipment leases, and various other items necessary in the normal course of business.
CONSOL Energy and CNX Gas enter into long-term unconditional purchase obligations to procure major equipment purchases, natural gas firm transportation, gas drilling services and other operating goods and services. These purchase obligations are not recorded on the Consolidated Balance Sheet. As of June 30, 2012, the purchase obligations for each of the next five years and beyond were as follows:

Obligations Due	Amount
Less than 1 year	$532,315
1 - 3 years	393,635
3 - 5 years	503,786
More than 5 years	1,552,111
Total Purchase Obligations	$2,981,847

Costs related to these purchase obligations include:

	Three Months Ended June, 30		Six Months Ended June 30,	
	2012	2011	2012	2011
Major equipment purchases	$31,989	$9,522	$45,175	$17,177
Firm transportation expense	15,822	15,316	30,867	28,134
Gas drilling obligations	28,517	26,244	58,093	52,062
Other	129	89	427	190

Total costs related to purchase obligations	$76,457	$51,171	$134,562	$97,563

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NOTE 12—DERIVATIVE INSTRUMENTS:
CONSOL Energy enters into financial derivative instruments to manage our exposure to commodity price volatility. We measure each derivative instrument at fair value and record it on the balance sheet as either an asset or liability. The fair value of CONSOL Energy's derivatives (natural gas price swaps) are based on intra-bank pricing models which utilize inputs that are either readily available in the public market, such as natural gas forward curves, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by our counterparties for reasonableness. Changes in the fair value of the derivatives are recorded currently in earnings unless special hedge accounting criteria are met. For derivatives designated as fair value hedges, the changes in fair value of both the derivative instrument and the hedged item are recorded in earnings. For derivatives designated as cash flow hedges, the effective portions of changes in fair value of the derivative are reported in Other Comprehensive Income or Loss (OCI) and reclassified into earnings in the same period or periods which the forecasted transaction affects earnings. The ineffective portions of hedges are recognized in earnings in the current period. CONSOL Energy currently utilizes only cash flow hedges that are considered highly effective.
CONSOL Energy formally assesses both at inception of the hedge and on an ongoing basis whether each derivative is highly effective in offsetting changes in the fair values or the cash flows of the hedged item. If it is determined that a derivative is not highly effective as a hedge or if a derivative ceases to be a highly effective hedge, CONSOL Energy will discontinue hedge accounting prospectively.
CONSOL Energy is exposed to credit risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is subject to continuing review. The Company has not experienced any issues of non-performance by derivative counterparties.
CONSOL Energy has entered into swap contracts for natural gas to manage the price risk associated with the forecasted natural gas revenues. The objective of these hedges is to reduce the variability of the cash flows associated with the forecasted revenues from the underlying commodity. As of June 30, 2012, the total notional amount of the Company’s outstanding natural gas swap contracts was 162.7 billion cubic feet. These swap contracts are forecasted to settle through December 31, 2015 and meet the criteria for cash flow hedge accounting. During the next twelve months, $78,123 of unrealized gain is expected to be reclassified from Other Comprehensive Income and into earnings, as a result of the settlement of cash flow hedges. No gains or losses have been reclassified into earnings as a result of the discontinuance of cash flow hedges.
The fair value at June 30, 2012 of CONSOL Energy's derivative instruments, which were all natural gas swaps and qualify as cash flow hedges, was an asset of $222,942 and a liability of $2,868. The total asset is comprised of $129,075 and $93,867 which were included in Prepaid Expense and Other Assets, respectively, on the Consolidated Balance Sheets. The total liability is comprised of $6 and $2,862 which were included in Other Accrued Liabilities and Other Liabilities, respectively, on the Consolidated Balance Sheets.
The fair value at December 31, 2011 of CONSOL Energy's derivative instruments, which were all natural gas swaps and qualify as cash flow hedges, was an asset of $251,277. The total asset is comprised of $153,376 and $97,901 which were included in Prepaid Expense and Other Assets, respectively, on the Consolidated Balance Sheets.

The effect of derivative instruments in cash flow hedging relationships on the Consolidated Statements of Income and the Consolidated Statements of Stockholders' Equity were as follows:

	Three Months Ended June 30,	
	2012	2011
Natural Gas Price Swaps		
Gain recognized in Accumulated OCI	$ 10,663	$ 28,430
Gain reclassified from Accumulated OCI into Outside Sales	$ 57,847	$ 16,905
Gain/(Loss) recognized in Outside Sales for ineffectiveness	$ 882	$ 72

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	Six Months Ended June 30,	
	2012	2011
Natural Gas Price Swaps		
Gain recognized in Accumulated OCI	$ 86,739	$ 32,801
Gain reclassified from Accumulated OCI into Outside Sales	$ 105,788	$ 35,745
Gain/(Loss) recognized in Outside Sales for ineffectiveness	$ 47	$ (36)

NOTE 13—FAIR VALUE OF FINANCIAL INSTRUMENTS:
The financial instruments measured at fair value on a recurring basis are summarized below:

	Fair Value Measurements at June 30, 2012			Fair Value Measurements at December 31, 2011		
Description	Quoted Prices in Active Markets for Identical Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Quoted Prices in Active Markets for Identical Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Gas Cash Flow Hedges	$—	$ 220,074	$—	$—	$ 251,277	$—

The following methods and assumptions were used to estimate the fair value for which the fair value option was not elected:
Cash and cash equivalents: The carrying amount reported in the balance sheets for cash and cash equivalents approximates its fair value due to the short-term maturity of these instruments.
Restricted cash: The carrying amount reported in the balance sheets for restricted cash approximates its fair value due to the short-term maturity of these instruments.
Long-term debt: The fair value of long-term debt is measured using unadjusted quoted market prices or estimated using discounted cash flow analyses. The discounted cash flow analyses are based on current market rates for instruments with similar cash flows.
The carrying amounts and fair values of financial instruments for which the fair value option was not elected are as follows:

	June 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 200,207	$ 200,207	$ 375,736	$ 375,736
Restricted cash	$ 20,365	$ 20,365	$ 22,148	$ 22,148
Long-term debt	$ (3,133,993)	$ (3,188,986)	$ (3,133,993)	$ (3,422,452)

NOTE 14—SEGMENT INFORMATION:

CONSOL Energy has two principal business divisions: Coal and Gas. The principal activities of the Coal division are mining, preparation and marketing of thermal coal, sold primarily to power generators, and metallurgical coal, sold to metal and coke producers. The Coal division includes four reportable segments. These reportable segments are Thermal, Low Volatile Metallurgical, High Volatile Metallurgical and Other Coal. Each of these reportable segments includes a number of operating segments (mines or type of coal sold). For the six months ended June 30, 2012, the Thermal aggregated segment includes the following mines: Bailey, Blacksville #2, Enlow Fork, Fola Complex, Loveridge, McElroy, Miller Creek Complex, Robinson Run and Shoemaker. For the six months ended June 30, 2012, the Low Volatile Metallurgical aggregated segment includes the Buchanan Mine and Amonate Complex. For the six months ended June 30, 2012, the High Volatile Metallurgical aggregated segment includes: Bailey, Blacksville #2, Enlow Fork, Fola Complex, Loveridge and Robinson Run coal sales. The Other Coal segment includes our purchased coal activities, idled mine activities, general and administrative activities as well as various other activities assigned to the Coal division but not allocated to each individual mine. The principal activity of the Gas division is to produce pipeline quality natural gas for sale primarily to gas wholesalers. The Gas division includes four reportable segments. These reportable segments are Coalbed Methane, Marcellus, Shallow Oil and Gas and Other Gas. The Other Gas segment includes our purchased gas activities, general and administrative activities as well as various other activities assigned to the Gas division but not allocated to each individual well type. CONSOL Energy’s All Other segment includes terminal services, river and dock services, industrial supply services, general and administrative activities and other business activities. Intersegment sales have been recorded at amounts approximating market. Operating profit for each segment is based on sales less identifiable operating and non-operating expenses. Assets are reflected at the division level only (coal, gas and other) and are not allocated between each individual segment. This presentation is consistent with the information regularly reviewed by the chief operating decision maker. The assets are not allocated to each individual segment due to the diverse asset base controlled by CONSOL Energy where each individual asset may service more than one segment within the division. An allocation of such asset base would not be meaningful or representative on a segment by segment basis.

Industry segment results for the three months ended June 30, 2012 are:

	Thermal	Low Volatile Metallurgical	High Volatile Metallurgical	Other Coal	Total Coal	Coalbed Methane	Marcellus Shale	Shallow Oil and Gas	Other Gas	Total Gas	All Other
Sales—outside	$748,303	$120,481	$71,250	$4,736	$944,770	$88,080	$23,730	$34,207	$2,082	$148,099	$96,4
Sales—purchased gas	—	—	—	—	—	—	—	—	651	651	—
Sales—gas royalty interests	—	—	—	—	—	—	—	—	9,533	9,533	—
Freight—outside	—	—	—	49,472	49,472	—	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	360	360	36,13
Total Sales and Freight	$748,303	$120,481	$71,250	$54,208	$994,242	$88,080	$23,730	$34,207	$12,626	$158,643	$132,
Earnings (Loss) Before Income Taxes	$133,363	$42,760	$19,666	$56,590	$252,379	$24,344	$4,835	$(2,410)	$(25,625)	$1,144	$19,7
Segment assets					$5,445,502					$5,970,939	$360,
Depreciation, depletion and amortization					$100,684					$47,326	$(5,7
Capital expenditures					$253,587					$143,206	$11,1

(A) Included in the Coal segment are sales of $136,576 to First Energy and $181,566 to Xcoal Energy & Resources each comprising over 10% of sales.

(B) Includes equity in earnings of unconsolidated affiliates of $1,483, $2,037 and $3,648 for Coal, Gas and All Other, respectively.

(C) Includes investments in unconsolidated equity affiliates of $21,090, $132,545 and $55,638 for Coal, Gas and All Other, respectively.

Industry segment results for the three months ended June 30, 2011 are:

	Thermal	Low Volatile Metallurgical	High Volatile Metallurgical	Other Coal	Total Coal	Coalbed Methane	Marcellus Shale	Shallow Oil and Gas	Other Gas	Total Gas	A C
Sales—outside	$781,380	$279,171	$117,688	$33,508	$1,211,747	$115,985	$28,238	$42,180	$2,638	$189,041	$
Sales—purchased gas	—	—	—	—	—	—	—	—	1,162	1,162	–
Sales—gas royalty interests	—	—	—	—	—	—	—	—	16,273	16,273	–
Freight—outside	—	—	—	59,572	59,572	—	—	—	—	—	–
Intersegment transfers	—	—	—	—	—	—	—	—	929	929	5
Total Sales and Freight	$781,380	$279,171	$117,688	$93,080	$1,271,319	$115,985	$28,238	$42,180	$21,002	$207,405	$
Earnings (Loss) Before Income Taxes	$126,183	$187,193	$48,869	$(210,095)	$152,150	$43,660	$7,468	$624	$(23,506)	$28,246	$
Segment assets					$5,026,836					$6,096,958	$
Depreciation, depletion and amortization					$101,915					$51,314	$
Capital expenditures					$152,700					$168,599	$

(D) Included in the Coal segment are sales of $189,529 to Xcoal Energy & Resources comprising over 10% of sales.

(E) Includes equity in earnings of unconsolidated affiliates of $4,240, $517 and $1,074 for Coal, Gas and All Other, respectively.

(F) Includes investments in unconsolidated equity affiliates of $26,995, $24,570 and $49,386 for Coal, Gas and All Other, respectively.

Industry segment results for the six months ended June 30, 2012 are:

	Thermal	Low Volatile Metallurgical	High Volatile Metallurgical	Other Coal	Total Coal	Coalbed Methane	Marcellus Shale	Shallow Oil and Gas	Other Gas	Total Gas
Sales—outside	$1,560,356	$293,221	$131,818	$13,691	$1,999,086	$187,615	$47,521	$68,580	$4,586	$308,302
Sales—purchased gas	—	—	—	—	—	—	—	—	1,490	1,490
Sales—gas royalty interests	—	—	—	—	—	—	—	—	21,739	21,739
Freight—outside	—	—	—	98,765	98,765	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	826	826
Total Sales and Freight	$1,560,356	$293,221	$131,818	$112,456	$2,097,851	$187,615	$47,521	$68,580	$28,641	$332,357
Earnings (Loss) Before Income Taxes	$261,893	$122,121	$35,602	$(4,767)	$414,849	$60,734	$8,086	$(6,132)	$(49,044)	$13,644
Segment assets					$5,445,502					$5,970,939
Depreciation, depletion and amortization					$201,446					$96,129
Capital expenditures					$448,016					$241,661

(G) Included in the Coal segment are sales of $280,731 to First Energy and $319,907 to Xcoal Energy & Resources each comprising over 10% of sales.

(H) Includes equity in earnings of unconsolidated affiliates of $6,290, $3,981 and $4,832 for Coal, Gas and All Other, respectively.

(I) Includes investments in unconsolidated equity affiliates of $21,090, $132,545 and $55,638 for Coal, Gas and All Other, respectively.

Industry segment results for the six months ended June 30, 2011 are:

	Thermal	Low Volatile Metallurgical	High Volatile Metallurgical	Other Coal	Total Coal	Coalbed Methane	Marcellus Shale	Shallow Oil and Gas	Other Gas	Total Gas
Sales—outside	$1,583,332	$516,066	$195,921	$46,872	$2,342,191	$229,759	$49,280	$80,925	$5,286	$365,250
Sales—purchased gas	—	—	—	—	—	—	—	—	2,142	2,142
Sales—gas royalty interests	—	—	—	—	—	—	—	—	35,108	35,108
Freight—outside	—	—	—	96,440	96,440	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	1,922	1,922
Total Sales and Freight	$1,583,332	$516,066	$195,921	$143,312	$2,438,631	$229,759	$49,280	$80,925	$44,458	$404,422
Earnings (Loss) Before Income Taxes	$320,227	$329,787	$89,762	$(288,934)	$450,842	$93,663	$15,971	$(2,126)	$(55,086)	$52,422
Segment assets					$5,026,836					$6,096,958
Depreciation, depletion and amortization					$196,996					$100,978
Capital expenditures					$253,230					$319,237

(J) Included in the Coal segment are sales of $379,726 to Xcoal Energy & Resources comprising over 10% of sales

(K) Includes equity in earnings of unconsolidated affiliates of $8,702, $1,001 and $1,609 for Coal, Gas and All Other, respectively.

(L) Includes investments in unconsolidated equity affiliates of $26,995, $24,570 and $49,386 for Coal, Gas and All Other, respectively.

Reconciliation of Segment Information to Consolidated Amounts:
Earnings Before Income Taxes:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
Segment Earnings Before Income Taxes for total reportable business segments	$253,523	$180,396	$428,493	$503,264
Segment Earnings Before Income Taxes for all other businesses	19,764	4,422	23,847	2,573
Interest income (expense), net and other non-operating activity (M)	(58,943)	(67,339)	(118,985)	(136,625)
Other Corporate Items (M)	(2,689)	(2,605)	(3,123)	(3,261)
Loss on debt extinguishment	—	(16,090)		(16,090)
Earnings Before Income Taxes	$211,655	$98,784	$330,232	$349,861

Total Assets:	June, 30	
	2012	2011
Segment assets for total reportable business segments	$11,416,441	$11,123,794
Segment assets for all other businesses	360,673	317,677
Items excluded from segment assets:		
Cash and other investments (M)	186,611	25,852
Recoverable income taxes	—	44,920
Deferred tax assets	588,722	636,193
Bond issuance costs	45,449	52,682
Total Consolidated Assets	$12,597,896	$12,201,118

(M) Excludes amounts specifically related to the gas segment.

NOTE 15—GUARANTOR SUBSIDIARIES FINANCIAL INFORMATION:
The payment obligations under the $1,500,000, 8.000% per annum notes due April 1, 2017, the $1,250,000, 8.250% per annum notes due April 1, 2020, and the $250,000, 6.375% per annum notes due March 1, 2021 issued by CONSOL Energy are jointly and severally, and also fully and unconditionally guaranteed by substantially all subsidiaries of CONSOL Energy. In accordance with positions established by the Securities and Exchange Commission (SEC), the following financial information sets forth separate financial information with respect to the parent, CNX Gas, a guarantor subsidiary, the remaining guarantor subsidiaries and the non-guarantor subsidiaries. The principal elimination entries include investments in subsidiaries and certain intercompany balances and transactions. CONSOL Energy, the parent, and a guarantor subsidiary manage several assets and liabilities of all other wholly owned subsidiaries. These include, for example, deferred tax assets, cash and other post-employment liabilities. These assets and liabilities are reflected as parent company or guarantor company amounts for purposes of this presentation.

Income Statement for the three months ended June 30, 2012 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$148,459	$976,515	$64,785	$(466)	$1,189,293
Sales—Gas Royalty Interests	—	9,533	—	—	—	9,533
Sales—Purchased Gas	—	651	—	—	—	651
Freight—Outside	—	—	49,472	—	—	49,472
Other Income (including equity earnings)	250,416	18,098	30,352	5,215	(98,543)	205,538
Total Revenue and Other Income	250,416	176,741	1,056,339	70,000	(99,009)	1,454,487
Cost of Goods Sold and Other Operating Charges	22,351	101,695	662,457	62,811	7,575	856,889
Gas Royalty Interests' Costs	—	7,131	—	—	(7)	7,124
Purchased Gas Costs	—	869	—	—	—	869
Related Party Activity	(15,104)	—	22,782	447	(8,125)	—
Freight Expense	—	—	49,472	—	—	49,472
Selling, General and Administrative Expense	—	9,313	24,185	234	—	33,732
Depreciation, Depletion and Amortization	3,986	47,326	101,994	518	—	153,824
Interest Expense	52,932	1,191	2,560	11	(101)	56,593
Taxes Other Than Income	663	8,164	74,789	713	—	84,329
Total Costs	64,828	175,689	938,239	64,734	(658)	1,242,832
Earnings (Loss) Before Income Taxes	185,588	1,052	118,100	5,266	(98,351)	211,655
Income Tax Expense (Benefit)	32,849	326	23,788	1,982	—	58,945
Net Income (Loss)	152,739	726	94,312	3,284	(98,351)	152,710
Add: Net Loss Attributable to Noncontrolling Interest	—	29	—	—	—	29
	$152,739	$755	$94,312	$3,284	$(98,351)	$152,739

Net Income Attributable
to CONSOL Energy Inc.
Shareholders

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Balance Sheet at June 30, 2012 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Assets:						
Current Assets:						
Cash and Cash Equivalents	$185,128	$14,281	$120	$678	$—	$200,207
Accounts and Notes Receivable:						
Trade	—	41,260	454	375,124	—	416,838
Notes Receivable	2,564	311,754	328	—	—	314,646
Other	2,635	84,777	7,727	4,458	—	99,597
Inventories	—	12,972	253,328	38,761	—	305,061
Deferred Income Taxes	190,075	(41,098)	—	—	—	148,977
Prepaid Expenses	11,079	133,685	49,042	1,491	—	195,297
Total Current Assets	391,481	557,631	310,999	420,512	—	1,680,623
Property, Plant and Equipment:						
Property, Plant and Equipment	210,967	5,710,088	8,791,013	24,271	—	14,736,339
Less-Accumulated Depreciation, Depletion and Amortization	117,370	871,556	4,059,107	17,429	—	5,065,462
Property, Plant and Equipment-Net	93,597	4,838,532	4,731,906	6,842	—	9,670,877
Other Assets:						
Deferred Income Taxes	897,934	(458,189)	—	—	—	439,745
Restricted Cash	20,365	—	—	—	—	20,365
Investment in Affiliates	9,532,321	132,545	745,871	—	(10,201,464)	209,273
Notes Receivable	3,963	296,344	—	—	—	300,307
Other	122,937	104,783	39,126	9,860	—	276,706
Total Other Assets	10,577,520	75,483	784,997	9,860	(10,201,464)	1,246,396
Total Assets	$11,062,598	$5,471,646	$5,827,902	$437,214	$(10,201,464)	$12,597,896
Liabilities and Stockholders’ Equity:						
Current Liabilities:						
Accounts Payable	$173,906	$202,547	$85,694	$10,657	$—	$472,804
Accounts Payable (Recoverable)—Related Parties	3,063,218	4,803	(3,339,571)	271,550	—	—
Current Portion Long-Term Debt	708	5,930	13,533	691	—	20,862
Accrued Income Taxes	30,228	4,837	—	—	—	35,065
Other Accrued Liabilities	609,693	51,236	72,372	10,885	—	744,186
Total Current Liabilities	3,877,753	269,353	(3,167,972)	293,783	—	1,272,917
Long-Term Debt:	3,000,975	48,523	124,644	1,124	—	3,175,266
Deferred Credits and Other Liabilities						
Postretirement Benefits Other Than Pensions	—	—	2,971,297	—	—	2,971,297
Pneumoconiosis Benefits	—	—	175,611	—	—	175,611
Mine Closing	—	—	441,670	—	—	441,670
Gas Well Closing	—	77,443	67,134	—	—	144,577
Workers’ Compensation	—	—	149,747	260	—	150,007

Salary Retirement	208,506	—	—	—	—	208,506
Reclamation	—	—	56,184	—	—	56,184
Other	105,373	22,275	3,901	—	—	131,549
Total Deferred Credits and Other Liabilities	313,879	99,718	3,865,544	260	—	4,279,401
Total Stockholders' Equity	3,869,991	5,053,731	5,005,686	142,047	(10,201,464)	3,869,991
Noncontrolling Interest	—	321	—	—	—	321
Total Liabilities and Stockholders' Equity	$11,062,598	$5,471,646	$5,827,902	$437,214	$(10,201,464)	$12,597,896

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Income Statement for the three months ended June 30, 2011 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$189,970	$1,241,265	$56,058	$(1,293)	$1,486,000
Sales—Gas Royalty Interests	—	16,273	—	—	—	16,273
Sales—Purchased Gas	—	1,162	—	—	—	1,162
Freight—Outside	—	—	59,572	—	—	59,572
Other Income (including equity earnings)	149,780	2,635	10,216	9,355	(147,065)	24,921
Total Revenue and Other Income	149,780	210,040	1,311,053	65,413	(148,358)	1,587,928
Cost of Goods Sold and Other Operating Charges	34,424	92,207	700,615	53,718	46,435	927,399
Gas Royalty Interests' Costs	—	14,379	—	—	(13)	14,366
Purchased Gas Costs	—	1,776	—	—	—	1,776
Loss on Debt Extinguishment	16,090	—	—	—	—	16,090
Related Party Activity	704	—	(10,996)	535	9,757	—
Freight Expense	—	—	59,572	—	—	59,572
Selling, General and Administrative Expense	—	11,394	80,415	317	(48,703)	43,423
Depreciation, Depletion and Amortization	3,003	51,314	102,864	619	—	157,800
Abandonment of Long-Lived Assets	—	—	115,479	—	—	115,479
Interest Expense	59,286	2,552	2,841	14	(96)	64,597
Taxes Other Than Income	1,883	8,269	77,760	730	—	88,642
Total Costs	115,390	181,891	1,128,550	55,933	7,380	1,489,144
Earnings (Loss) Before Income Taxes	34,390	28,149	182,503	9,480	(155,738)	98,784
Income Tax Expense (Benefit)	(42,994)	11,034	49,774	3,586	—	21,400
Net Income (Loss)	$77,384	$17,115	$132,729	$5,894	$(155,738)	$77,384

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Balance Sheet at December 31, 2011:

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Assets:						
Current Assets:						
Cash and Cash Equivalents	$37,342	$336,727	$1,269	$398	$—	$375,736
Accounts and Notes Receivable:						
Trade	—	63,299	500	399,013	—	462,812
Notes Receivable	2,669	311,754	527	—	—	314,950
Other	2,913	91,582	7,458	3,755	—	105,708
Inventories	—	8,600	206,096	43,639	—	258,335
Deferred Income Taxes	191,689	(50,606)	—	—	—	141,083
Prepaid Expenses	28,470	159,900	49,224	1,759	—	239,353
Total Current Assets	263,083	921,256	265,074	448,564	—	1,897,977
Property, Plant and Equipment:						
Property, Plant and Equipment	198,004	5,488,094	8,376,831	24,390	—	14,087,319
Less-Accumulated Depreciation, Depletion and Amortization	109,924	778,716	3,855,323	16,940	—	4,760,903
Property, Plant and Equipment-Net	88,080	4,709,378	4,521,508	7,450	—	9,326,416
Other Assets:						
Deferred Income Taxes	963,332	(455,608)	—	—	—	507,724
Restricted Cash	22,148	—	—	—	—	22,148
Investment in Affiliates	9,126,453	96,914	760,548	—	(9,801,879)	182,036
Notes Receivable	4,148	296,344	—	—	—	300,492
Other	116,624	110,128	52,009	10,146	—	288,907
Total Other Assets	10,232,705	47,778	812,557	10,146	(9,801,879)	1,301,307
Total Assets	$10,583,868	$5,678,412	$5,599,139	$466,160	$(9,801,879)	$12,525,700
Liabilities and Stockholders' Equity:						
Current Liabilities:						
Accounts Payable	$140,823	$206,072	$164,521	$10,587	$—	$522,003
Accounts Payable (Recoverable)-Related Parties	2,900,546	9,431	(3,222,648)	312,671	—	—
Current Portion of Long-Term Debt	805	5,587	13,543	756	—	20,691
Accrued Income Taxes	68,819	6,814	—	—	—	75,633
Other Accrued Liabilities	493,450	58,401	206,649	11,570	—	770,070
Total Current Liabilities	3,604,443	286,305	(2,837,935)	335,584	—	1,388,397
Long-Term Debt:	3,001,092	50,326	124,674	1,331	—	3,177,423
Deferred Credits and Other Liabilities:						
Postretirement Benefits Other Than Pensions	—	—	3,059,671	—	—	3,059,671
Pneumoconiosis Benefits	—	—	173,553	—	—	173,553
Mine Closing	—	—	406,712	—	—	406,712
Gas Well Closing	—	61,954	62,097	—	—	124,051

Workers’ Compensation	—	—	150,786	248	—	151,034
Salary Retirement	269,069	—	—	—	—	269,069
Reclamation	—	—	39,969	—	—	39,969
Other	98,379	16,899	9,658	—	—	124,936
Total Deferred Credits and Other Liabilities	367,448	78,853	3,902,446	248	—	4,348,995
Total Stockholders’ Equity	3,610,885	5,262,928	4,409,954	128,997	(9,801,879)	3,610,885
Total Liabilities and Stockholders’ Equity	$10,583,868	$5,678,412	$5,599,139	$466,160	$(9,801,879)	$12,525,700

Income Statement for the six months ended June 30, 2012 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$309,128	$2,058,803	$133,807	$(974)	$2,500,764
Sales—Gas Royalty Interests	—	21,739	—	—	—	21,739
Sales—Purchased Gas	—	1,490	—	—	—	1,490
Freight—Outside	—	—	98,765	—	—	98,765
Other Income (including equity earnings)	420,439	34,403	60,055	11,172	(267,570)	258,499
Total Revenue and Other Income	420,439	366,760	2,217,623	144,979	(268,544)	2,881,257
Cost of Goods Sold and Other Operating Charges	71,531	200,340	1,345,213	129,227	14,619	1,760,930
Gas Royalty Interests' Costs	—	17,386	—	—	(13)	17,373
Purchased Gas Costs	—	1,386	—	—	—	1,386
Related Party Activity	(9,089)	—	24,040	949	(15,900)	—
Freight Expense	—	—	98,765	—	—	98,765
Selling, General and Administrative Expense	—	19,293	52,757	681	—	72,731
Depreciation, Depletion and Amortization	7,905	96,129	204,096	1,041	—	309,171
Interest Expense	107,694	2,409	4,789	22	(201)	114,713
Taxes Other Than Income	3,337	16,364	154,722	1,533	—	175,956
Total Costs	181,378	353,307	1,884,382	133,453	(1,495)	2,551,025
Earnings (Loss) Before Income Taxes	239,061	13,453	333,241	11,526	(267,049)	330,232
Income Tax Expense (Benefit)	(10,874)	5,273	81,577	4,350	—	80,326
Net Income (Loss)	249,935	8,180	251,664	7,176	(267,049)	249,906
Add: Net Loss Attributable to Noncontrolling Interest	—	29	—	—	—	29
Net Income Attributable to CONSOL Energy Inc. Shareholders	$249,935	$8,209	$251,664	$7,176	$(267,049)	$249,935

Income Statement for the six months ended June 30, 2011 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$367,172	$2,396,615	$110,154	$(2,463)	$2,871,478
Sales—Gas Royalty Interests	—	35,108	—	—	—	35,108
Sales—Purchased Gas	—	2,142	—	—	—	2,142
Freight—Outside	—	—	96,440	—	—	96,440
Other Income (including equity earnings)	396,644	4,315	21,637	18,596	(393,055)	48,137
Total Revenue and Other Income	396,644	408,737	2,514,692	128,750	(395,518)	3,053,305
Cost of Goods Sold and Other Operating Charges	63,400	178,577	1,345,161	107,705	46,265	1,741,108
Gas Royalty Interests' Costs	—	31,200	—	—	(27)	31,173
Purchased Gas Costs	—	2,452	—	—	—	2,452
Loss on Debt Extinguishment	16,090	—	—	—	—	16,090
Related Party Activity	(2,536)	—	(12,737)	1,001	14,272	—
Freight Expense	—	—	96,251	—	—	96,251
Selling, General and Administrative Expense	—	21,992	109,730	600	(48,703)	83,619
Depreciation, Depletion and Amortization	5,364	100,978	199,272	1,248	—	306,862
Abandonment of Long-Lived Assets	—	—	115,479	—	—	115,479
Interest Expense	120,428	5,232	5,583	27	(191)	131,079
Taxes Other Than Income	3,386	16,076	158,274	1,595	—	179,331
Total Costs	206,132	356,507	2,017,013	112,176	11,616	2,703,444
Earnings (Loss) Before Income Taxes	190,512	52,230	497,679	16,574	(407,134)	349,861
Income Tax Expense (Benefit)	(79,021)	20,469	132,611	6,269	—	80,328
Net Income (Loss)	$269,533	$31,761	$365,068	$10,305	$(407,134)	$269,533

Cash Flow for the Six Months Ended June 30, 2012 (unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Cash Provided by (Used In) Operating Activities	$271,127	$124,367	$(28,281)	$736	$—	$367,949
Cash Flows from Investing Activities:						
Capital Expenditures	$(24,722)	$(241,661)	$(448,016)	$—	$—	$(714,399)
Investment in Equity Affiliates	—	(35,150)	(750)	—	—	(35,900)
Distributions from Equity Affiliates	—	3,500	10,561	—	—	14,061
Other Investing Activities	169,500	30,249	52,469	11	—	252,229
Net Cash Provided by (Used in) Investing Activities	$144,778	$(243,062)	$(385,736)	$11	$—	$(484,009)
Cash Flows from Financing Activities:						
Dividends Received (Paid)	$143,167	$(200,000)	$—	$—	$—	$(56,833)
Other Financing Activities	1,580	(3,751)	2	(467)	—	(2,636)
Net Cash Provided by (Used in) Financing Activities	$144,747	$(203,751)	$2	$(467)	$—	$(59,469)

Cash Flow for the Six Months Ended June 30, 2011 (unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Cash Provided by (Used In) Operating Activities	$370,780	$182,364	$243,823	$(1,484)	$—	$795,483
Cash Flows from Investing Activities:						
Capital Expenditures	$(12,974)	$(319,237)	$(253,230)	$—	$—	$(585,441)
Distributions from Equity Affiliates	—	—	3,870	—	—	3,870
Other Investing Activities	10	1,106	4,897	1,467	—	7,480
Net Cash (Used in) Provided by Investing Activities	$(12,964)	$(318,131)	$(244,463)	$1,467	$—	$(574,091)
Cash Flows from Financing Activities:						
Dividends Paid	$(45,293)	$—	$—	$—	$—	$(45,293)
(Payments on) Proceeds from Short-Term Borrowings	(155,000)	131,750	—	—	—	(23,250)
Payments on Securitization Facility	(130,000)	—	—	—	—	(130,000)
Payments on Long-Term Notes, including Redemption Premium	(265,785)	—	—	—	—	(265,785)
Proceeds from Issuance of Long-Term Notes	250,000	—	—	—	—	250,000
Debt Issuance and Financing Fees	(10,360)	(5,067)	—	—	—	(15,427)
Other Financing Activities	8,740	(6,138)	(109)	(405)	—	2,088
Net Cash Provided by (Used in) Financing Activities	$(347,698)	$120,545	$(109)	$(405)	$—	$(227,667)

Statement of Comprehensive Income for the Three Months Ended June 30, 2012 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income	$152,739	$726	$94,312	$3,284	$(98,351)	$152,710
Other Comprehensive Income (Loss):						
Actuarially Determined Long-Term Liability Adjustments						
Amortization of Prior Service Cost	(8,683)	—	(8,767)	—	8,767	(8,683)
Amortization of Net Loss	16,269	—	18,820	—	(18,820)	16,269
Net Increase in the Value of Cash Flow Hedge	10,663	10,663	—	—	(10,663)	10,663
Reclassification of Cash Flow Hedges from Other Comprehensive Income to Earnings	(57,847)	(57,847)	—	—	57,847	(57,847)
Other Comprehensive Income (Loss):	(39,598)	(47,184)	10,053	—	37,131	(39,598)
Comprehensive Income	113,141	(46,458)	104,365	3,284	(61,220)	113,112
Add: Comprehensive Loss Attributable to Noncontrolling Interest	—	29	—	—	—	29
Comprehensive Income (Loss) Attributable to CONSOL Energy Inc. Shareholders'	$113,141	$(46,429)	$104,365	$3,284	$(61,220)	$113,141

Statement of Comprehensive Income for the Three Months Ended June 30, 2011 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income	$77,384	$17,115	$132,729	$5,894	$(155,738)	$77,384
Other Comprehensive Income (Loss):						
Treasury Rate Lock	(76)	—	—	—	—	(76)
Actuarially Determined Long-Term Liability Adjustments						
Amortization of Prior Service Cost	(7,364)	—	(7,398)	—	7,398	(7,364)
Amortization of Net Loss	21,064	—	22,943	—	(22,943)	21,064
Net Increase in the Value of Cash Flow Hedge	28,430	28,430	—	—	(28,430)	28,430
Reclassification of Cash Flow Hedges from Other Comprehensive Income to Earnings	(16,905)	(16,905)	—	—	16,905	(16,905)
Other Comprehensive Income (Loss):	25,149	11,525	15,545	—	(27,070)	25,149
Comprehensive Income (Loss)	$102,533	$28,640	$148,274	$5,894	$(182,808)	$102,533

Statement of Comprehensive Income for the Six Months Ended June 30, 2012 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income	$249,935	$8,180	$251,664	$7,176	$(267,049)	$249,906
Other Comprehensive Income (Loss):						
Actuarially Determined Long-Term Liability Adjustments						
Change in Prior Service Cost	50,276	—	50,276	—	(50,276)	50,276
Amortization of Prior Service Cost	(16,237)	—	(16,067)	—	16,067	(16,237)
Amortization of Net Loss	33,120	—	28,019	—	(28,019)	33,120
Net Increase in the Value of Cash Flow Hedge	86,739	86,739	—	—	(86,739)	86,739
Reclassification of Cash Flow Hedges from Other Comprehensive Income to Earnings	(105,788)	(105,788)	—	—	105,788	(105,788)
Other Comprehensive Income (Loss):	48,110	(19,049)	62,228	—	(43,179)	48,110
Comprehensive Income	298,045	(10,869)	313,892	7,176	(310,228)	298,016
Add: Comprehensive Loss Attributable to Noncontrolling Interest	—	29	—	—	—	29
Comprehensive Income (Loss) Attributable to CONSOL Energy Inc. Shareholders'	$298,045	$(10,840)	$313,892	$7,176	$(310,228)	$298,045

Statement of Comprehensive Income for the Six Months Ended June 30, 2011 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income	$269,533	$31,761	$365,068	$10,305	$(407,134)	$269,533
Other Comprehensive Income (Loss):						
Treasury Rate Lock	(96)	—	—	—	—	(96)
Actuarially Determined Long-Term Liability Adjustments						
Amortization of Prior Service Cost	(14,729)	—	(14,660)	—	14,660	(14,729)
Amortization of Net Loss	36,756	—	32,998	—	(32,998)	36,756
Net Increase in the Value of Cash Flow Hedge	32,801	32,801	—	—	(32,801)	32,801
Reclassification of Cash Flow Hedges from Other Comprehensive Income to Earnings	(35,745)	(35,745)	—	—	35,745	(35,745)
Other Comprehensive Income (Loss):	18,987	(2,944)	18,338	—	(15,394)	18,987
Comprehensive Income (Loss)	$288,520	$28,817	$383,406	$10,305	$(422,528)	$288,520

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NOTE 16—RELATED PARTY TRANSACTIONS:

CONE Gathering LLC Related Party Transactions

During the six months ended June 30, 2012, CONE Gathering LLC (CONE), a 50% owned affiliate, provided CNX Gas Company gathering services in the ordinary course of business. Gathering services received from CONE were $4,262 and $7,724, for the three and six months ended June 30, 2012, respectively, which were included in Cost of Goods Sold on the Consolidated Statements of Income.

As of June 30, 2012 and December 31, 2011, CONSOL Energy and CNX Gas Company had a net receivable of $486 and $8,966, respectively, which were comprised of the following items:

	June 30, 2012	December 31, 2011	Location on Balance Sheet
CONE Gathering Capital Reimbursement	$ 2,033	$ 8,042	Accounts Receivable–Other
Reimbursement for CONE Expenses	4	2,009	Accounts Receivable–Other
Reimbursement for Services Provided to CONE	67	414	Accounts Receivable–Other
CONE Gathering Fee Payable	(1,618)	(1,499)	Accounts Payable
Net Receivable due from CONE	$ 486	$ 8,966	

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

The domestic coal and natural gas industries faced another challenging quarter as the effects of excess supply in both markets have continued to limit a recovery in prices. Flat electric demand, strong natural gas supply, and global economic uncertainties have sent inventories to historically high levels and kept coal and gas prices under pressure. The uncertain European economic situation and increased international supply reduced prices for thermal coals internationally, while pricing for metallurgical coals slipped due to oversupply in the world market.

Together, the unusually warm 2011-2012 winter and flat electric demand kept domestic thermal coal consumption low during the second quarter. As natural gas prices averaged below $3.00/MMBtu, natural gas-fired generation continued to gain market share from coal. Early estimates indicate that coal-fired generation produced 36% of the U.S. electric power sector during the second quarter compared with 43% during the same period in 2011. Likewise, utility coal stockpiles remained at elevated levels throughout the quarter, although this growth has recently declined. Warmer average spring temperatures, modest increases in the price of natural gas, and reductions in domestic thermal coal production have helped reduce the stress on the sector. The significant switching to natural gas has not built coal inventories as fast as might have been expected, largely due to customer pushback of deliveries and producer production cuts. This development should shorten the recovery period for coal prices.

In the longer-term, the outlook for domestic thermal coal faces regulatory challenges as new Environmental Protection Agency ("EPA") power plant rules encourage greater adoption of natural gas-fired generation. Few new-build coal-fired power plants are expected and utilities will likely retire older, smaller, and less competitive coal-fired units rather than invest in costly emissions controls to maintain compliance. International thermal coal demand is strong, but prices have fallen as U.S. tons have moved abroad to compete with Colombian and South African coals for European imports. European consumption has grown recently to take advantage of the cheaper coal prices and to offset decreases in nuclear generation, renewable energy subsidies and the removal of subsidized European mining.

During the second quarter, metallurgical coal prices fell from the prior quarter and were down significantly from the comparable period in 2011. Low-volatile coal continues to be oversupplied in a world economy that has weakened in the last three months. Steel utilization rates were weak in Europe and Brazil, which impacts CONSOL Energy's exports.

CONSOL Energy's coal sales outlook as of July 26, 2012 is as follows:

	Q3 2012	2012	2013	2014
Estimated Coal Sales (millions of tons)	14.9	59.4	57.6	62.0
Est. Low-Vol Met Sales	1.2	4.4	4.6	4.4
Tonnage: Firm	0.8	3.4	0.3	—
Avg. Price: Sold (Firm)	$139.87	$149.47	$126.65	$—
Price: Estimated (For open tonnage)	N/A	N/A	N/A	N/A
Est. High-Vol Met Sales	0.9	4.2	5.2	5.8
Tonnage: Firm	0.7	3.4	0.4	0.3
Avg. Price: Sold (Firm)	$72.40	$68.35	$72.11	$75.53
Price: Estimated (For open tonnage)	N/A	N/A	N/A	N/A
Est. Thermal Sales	12.7	50.5	47.2	51.2
Tonnage: Firm	12.5	49.7	25.1	17.7
Avg. Price: Sold (Firm)	$63.51	$62.37	$62.57	$63.91
Price: Estimated (For open tonnage)	N/A	N/A	N/A	N/A

Note: While most of the data in the table are single point estimates, the inherent uncertainty of markets and mining operations means
that investors should consider a reasonable range around these estimates. N/A means not available or not forecast. CONSOL Energy has chosen
not to forecast prices for open tonnage due to ongoing customer negotiations. In the thermal sales category, the open tonnage includes
4.7 million collared tons in 2013, with a ceiling of $59.78 per ton and a floor of $51.63 per ton. For 2014, the open tonnage in the thermal
sales category includes 7.0 million tons, with a ceiling of $59.31 per ton and a floor of $45.93 per ton. Total Amonate estimated coal sales
for Q3 2012 are 0.1 million tons. Calendar years 2012, 2013, and 2014 include 0.3, 0.6, and 0.6 million tons, respectively, from Amonate.
The Amonate tons are not included in the category breakdowns. None of the Amonate tons have been sold to date.

In response to current weak market conditions for domestic coal, CONSOL Energy announced during the quarter that it extended the annual miners' vacation period at its Blacksville No. 2 and Robinson Run mines in Northern West Virginia. The Blacksville No. 2 vacation period was extended for two weeks. Consistent with its core values of safety, compliance and continuous improvement, two belt rehabilitation projects were conducted during the extended vacation period. The longwall at Blacksville No. 2 was restarted the week of July 22, 2012. The Robinson Run extension was one week. Work was completed during the week extension to maintain the mine in a ready state. The longwall at Robinson Run restarted the week of July 16, 2012. The extended vacation periods are expected to reduce total annual Company production by 300 thousand tons.

Also in response to the current weak market conditions for domestic coal and recent proposals and final rules adopted by the EPA, CONSOL Energy issued a notice under the Workers Adjustment and Retraining Notification Act (WARN) of a layoff at its Fola Operations near Bickmore, West Virginia. The layoffs are expected to occur during a 14-day period beginning on August 30, 2012. Production from underground operations will continue until the layoffs occur. Production from the surface areas was idled as of June 29, 2012, and employees have been reassigned to reclamation activities. The idling of the Fola Complex is expected to reduce total annual Company production by approximately 800 thousand tons.

CONSOL Energy also idled the longwalls at Blacksville No. 2 and Buchanan Mine in March and April 2012. These longwalls resumed production on May 1, 2012.

On July 27, 2011 CONSOL Energy incurred a structural failure on its newly installed above-ground conveyor system at the Bailey Preparation Plant in Southwestern Pennsylvania. The belt system conveys coal from the Bailey and Enlow Fork mines to the Bailey Preparation Plant. CONSOL Energy is conducting a thorough assessment and initial indications are that coal from the Bailey and Enlow Fork mines could be fully impacted for an estimated two weeks. If, at the end of two weeks, one of the two collapsed belts is returned to service, the mines could operate at an estimated 60% of capacity. CONSOL Energy does not currently expect to curtail any domestic sales; however, overseas shipments in the spot market could be affected. Impacts related to this incident on the sales guidance table presented above are currently under review.

Natural gas production continues to be very strong, although there are indicators that growth rates have abated. Although still above last year's level, the rate of dry-gas growth has decreased as capital and drilling have shifted towards liquids-rich targets. Although prices have increased slightly, significant market opportunity exists for domestic gas-fired electric generation. Longer-term outlooks are strong as the abundant domestic supply may encourage widespread gas-fired electric-generation adoption and increased demand from the U.S. manufacturing and chemical industry. Recent EPA regulations have made natural gas the preferred fuel for future electric generation capacity growth.

Low natural gas prices have encouraged capital to be directed towards liquids-rich and oil producing plays. The number of rigs targeting dry gas, most noticeably in the traditional Barnett and Haynesville plays, has dropped while those targeting liquids-rich and oil-focused drilling has increased. Rig counts have fallen nationally to the lowest levels since 2009. However, the Marcellus region's production level has grown due to its advantageous proximity to the consuming regions of the Northeast United States. Although storage levels are still at record highs, warmer spring weather and increased demand, have slowed the growth in storage. A warm summer forecast is expected to give some relief to a strong gas supply base. CONSOL Energy expects its 2012 net gas production to be between 157 - 159 Bcf. Third quarter 2012 gas production, net to CONSOL Energy, is expected to be approximately 40 - 42 Bcf.

As the global economy faces another phase of European deliberations, concerns of lingering high U.S. unemployment and slowing Chinese economic growth, continue to exist. However, the reversal of unseasonal weather, small

increases in the price of natural gas, and domestic thermal production cuts have slightly improved the situation compared with the first quarter 2012.

The fundamental drivers for longer-term growth are strong. Because the developing world continues to invest strongly in electric generation infrastructure, CONSOL Energy expects the international thermal coal market to remain robust. Additionally, continued strong blast furnace demand in the U.S. and abroad signals a strong need for a competitively priced and secure supply of U.S. metallurgical and cross-over grade coals. Domestic demand for natural gas will continue to rise as industries exploit the current low prices and abundant supply. The fundamental and primary drivers of CONSOL Energy's business remain solid as the Company continues to produce the low-cost, reliable, and abundant fuels necessary to drive the growth of both industrialized and developing economies.

The following developments impacting CONSOL Energy occurred in the six months ended June 30, 2012:

- In June 2012, CONSOL Energy announced that it acquired a minority equity interest in Epiphany Solar Water

Systems, a privately-held company founded in New Castle, PA in 2009. Epiphany Solar Water Systems is testing what is believed to be the world's first concentrated solar powered water purification system. Under the agreement, CONSOL Energy has made an initial investment of $0.5 million and one of its Marcellus gas well locations in Greene County will serve as the site to pilot test this solar powered water purifications system. The pilot test is scheduled to begin in July with initial results expected in early fall.

- In June 2012, CONSOL Energy sold its non-producing Northern Powder River Basin assets in southern Montana and northern Wyoming for $170 million in cash to Cloud Peak Energy. Additionally, CONSOL Energy retained an 8% production royalty interest on approximately 200 million tons of permitted fee coal. This transaction resulted in a pre-tax gain of $151 million.

- In June 2012, CONSOL Energy expanded an existing mining joint venture with a privately-held company in Central Pennsylvania. The joint venture will self-fund, through retained earnings, a $54 million (gross) expansion in 2012 and 2013. The expansion will enable CONSOL Energy's share of high-vol A and mid-vol forecasted coal production to increase from 150,000 tons in 2012 to 900,000 tons in 2015.

- In April 2012, CONSOL Energy announced certain changes to the salaried other post-retirement benefit plan that current retirees and current active employees will receive as of January 1, 2014. The change provides a fixed annual retiree medical contribution into a Health Reimbursement Account for eligible employees. The money in the account can be used to help pay for a commercial medical plan, Medicare Part B and Part D premiums and other qualified expenses. Employees who work or worked in corporate or operational support positions at retirement and who are age 50 or older at December 31, 2013 will receive the revised benefit in lieu of the current retiree medical and prescription drug coverage. Employees who work or worked in corporate or operations support positions who are under age 50 at December 31, 2013 will receive no retiree medical or prescription drug benefit. CONSOL Energy remeasured the salaried other postretirement plan as of March 31, 2012 to recognize these changes. The remeasurement reflects the reduction in benefits and the change in discount rate from 4.51% at December 31, 2011 to 4.57% at March 31, 2012. The remeasurement resulted in a reduction of approximately $80.6 million of Other Post-Retirement Benefits (OPEB) liability with a corresponding offset to Other Comprehensive Income, net of applicable deferred taxes. The change resulted in a $3.1 million reduction in OPEB expense compared to what was originally expected to be recognized for the three months ended June 30, 2012. Additionally, the change will result in a $6.3 million reduction to OPEB expense compared to what was originally expected to be recognized for the remaining six months of 2012. The change was made to align CONSOL Energy's corporate and operational support compensation package more closely with our peer group.

- Pennsylvania enacted Act 13 of 2012, which provides for the comprehensive regulation of Marcellus Shale development in Pennsylvania. Among other things, Act 13 requires an impact fee be paid annually on all nonconventional gas wells drilled in the state. The annual fee is based on annual average sales price and is modified annually for a 15-year period for each well. The impact fee also required the first year fee be paid on all applicable wells drilled before January 1, 2012 with subsequent annual fees to apply each year thereafter. CONSOL Energy's retroactive impact fee related to wells drilled prior to January 1, 2012 was approximately $4 million.

- West Virginia has an alternative bond system (ABS) for coal mine reclamation which consists of (i) individual site bonds posted by the permittee that are less than the full estimated reclamation cost plus (ii) a bond pool (Special Reclamation Fund) funded by a per ton fee on coal mined in the State which is used to supplement the site specific bonds if needed in the event of bond forfeiture. The Special Reclamation Fund is currently underfunded. As a result of a decision by the U.S District Court in West Virginia in a citizens' suit concerning the adequacy of the Special Reclamation Fund, effective July 1, 2012, the rate per ton fee on coal mined in the state of West Virginia will be increased from $0.144 cents per ton to $0.279 per ton. CONSOL Energy expects to produce approximately 15 million tons of coal in West Virginia during the second half of 2012.

- In April 2012, CONSOL Energy sold its non-producing Elk Creek reserves in southern West Virginia. The transaction resulted in cash proceeds of approximately $25 million and a gain on sale of assets of approximately $10 million.

CONSOL Energy is managing several significant matters that may affect our business and impact our financial results in the future including the following:

- Challenges in the overall environment in which we operate create increased risks that we must continuously monitor and manage. These risks include (i) increased prices for commodities such as diesel fuel, synthetic rubber and steel that we use in our operations (although prices for some of these commodities declined during the quarter from

previous quarters), (ii) increased scrutiny of existing safety regulations and the development of new safety regulations and (iii) additional environmental restrictions.

Federal and state environmental regulators are reviewing our operations more closely and are more strictly interpreting and enforcing existing environmental laws and regulations, resulting in increased costs and delays. For example, we entered into a consent decree with the EPA and the West Virginia Department of Environmental Protection pursuant to which we agreed to construct an advanced technology mine water treatment plant and related facilities to reduce high levels of total dissolved solids in water discharges from certain of our mines in Northern West Virginia, at a total estimated cost of approximately $200 million. The new facility must be placed into service no later than May 2013.

Federal and state regulators have proposed regulations which, if adopted, would adversely impact our business. These proposed regulations could require significant changes in the manner in which we operate and/or would increase the cost of our operations. For example, the Department of Interior, Office of Surface Mining Reclamation and Enforcement (OSM) is currently preparing an environmental impact statement relating to OSM's consideration of five alternatives for amending its coal mining stream protection rules. All of the alternatives, except the no action alternative, could make it more costly to mine our coal and/or could eliminate the ability to mine some of our coal. Another example is the Cross-State Air Pollution Rule (CSAPR) that was finalized by the EPA on July 6, 2011, although the effective date of the rule has been stayed by a court. CSAPR replaces the Clean Air Interstate Rule and regulates the amount of sulfur dioxide (SO2) and nitrogen oxide (NOx) that power plants in 23 eastern States can emit in order to meet clean air requirements in downwind states. Another example is the Mercury and Air Toxic Standards issued by the EPA on December 16, 2011. The new regulations set mercury and air toxic standards for new and existing coal and oil fired electric utility steam generating units and include more stringent new source performance standards (NSPS) for particulate matter (PM), SO2 and NOx. Some older coal fired power plants may be retired or have operation time reduced rather than install additional expensive emission controls which could reduce the amount of coal consumed. On April 18, 2012, the EPA published new final New Source Performance Standards for gas wells and related facilities. These rules apply to wells that were hydraulically fractured after August, 23, 2011 and require the implementation by January 1, 2015 of technologies that capture the gas that is currently vented or flared during completion (hydrofracturing) of a well. Low pressure wells, including coalbed methane wells, are excluded from these new standards.

In April 2012, the EPA published its proposed New Source Performance Standards (NSPS) for carbon dioxide emissions from coal powered electric generating units. The public comment period has run and publication of the final rules is expected soon. The proposed rules will apply to new power plants and to existing plants that make major modifications. If the rules are adopted as proposed, the only new coal fired power plants that will be able to meet the proposed emission limits will be coal fired plants with carbon dioxide capture and storage (CCS). Commercial scale CCS is not likely to be available in the near future, and if available, it may make coal fired electric generation units uneconomical compared to new gas fired electric generation units. Thus, if finalized the proposed rules could seriously threaten the construction of new coal fired electric generating units.

On June 11, 2012, the governor of Ohio signed amendments to Ohio's existing oil and gas laws that regulate the natural gas industry's hydraulic fracturing and ancillary activities in the Utica/Point Pleasant shale. CONSOL Energy is currently reviewing the amendments for their potential impacts to our growing operations in that State.

On May 25, 2012, CONSOL Energy received a citizens' Notice of Intent to Sue from the Sierra Club, the Ohio Valley Environmental Coalition and the West Virginia Highlands Conservancy alleging violations of the Clean Water Act relating to selenium at its Fola mining complex in central West Virginia. CONSOL Energy is currently in discussions with the West Virginia Department of Environmental Protection concerning a consent order with the State relating to the alleged violations.

- In late June, CONSOL Energy received informal notification from the Pennsylvania Department of Environmental Protection of the Department's intent pursuant to a Technical Guidance Document entitled “Surface Water Protection-Underground Bituminous Coal Mining” to require a change in the mine plan of a pending application for a permit for expansion of the Company's Bailey East longwall mine. This change in mine plan could have a material effect on CONSOL Energy's forecasted production for 2015. Although CONSOL Energy does not agree that a modification of its mining plan is necessary to comply with applicable regulatory performance standards, CONSOL Energy is currently reviewing the notification and any modifications that would be required if CONSOL Energy is compelled to modify its application.

- CONSOL Energy continues to explore potential sales of non-core assets.

Results of Operations
Three Months Ended June 30, 2012 Compared with Three Months Ended June 30, 2011

Net Income
CONSOL Energy reported net income of $153 million, or $0.67 per diluted share, for the three months ended June 30, 2012. Net income was $77 million, or $0.34 per diluted share, for the three months ended June 30, 2011.
The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $252 million of earnings before income tax for the three months ended June 30, 2012 compared to $152 million for the three months ended June 30, 2011. The coal division sold 14.4 million tons of coal produced from CONSOL Energy mines, excluding our portion of tons sold from equity affiliates, for the three months ended June 30, 2012 compared to 16.2 million tons for the three months ended June 30, 2011.
The average sales price and average costs per ton for all active coal operations were as follows:

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per ton sold	$65.57	$73.08	$(7.51)	(10.3)%
Average Costs per ton sold	52.03	50.88	1.15	2.3 %
Margin	$13.54	$22.20	$(8.66)	(39.0)%

The average sales price per ton sold was lower in the period-to-period comparison due to weakened pricing in the metallurgical coal markets, slightly offset by strength in our contracted domestic thermal sales. The decreased sales tonnage is due to decreased coal demand in both thermal and metallurgical markets.

Changes in the average operating costs per ton sold were primarily related to the following items:

- Average costs per ton sold increased due to fewer tons sold. Fixed costs are allocated over fewer sales tons, resulting in higher unit costs.
- Average costs per ton sold increased due to the idling of longwalls at the Blacksville mine and the Buchanan mine during April 2012. The decrease in tonnage negatively impacted the average operating costs per ton sold by approximately $1.80 per ton.
- Average labor and labor-related costs per ton increased as a result of the impact of the $2.00 per hour worked United Mine Workers of America (UMWA) contract wage increases, offset, in part, by fewer hours worked.
- Average operating supplies and maintenance costs per ton increased due to increased gas well plugging expenses and increased maintenance project expenses.
- Average subsidence costs per ton decreased due to the settlement of a previously incurred subsidence liability for an amount lower than expected.
- Average provision costs per ton decreased due to the improvement in other postretirement benefits discussed in the long-term liabilities section below.

The total gas division includes coalbed methane (CBM), shallow oil and gas, Marcellus and other gas. The total gas division contributed $1 million of earnings before income tax for the three months ended June 30, 2012 compared to $28 million for the three months ended June 30, 2011. Total gas production was 37.3 billion cubic feet for the three months ended June 30, 2012 compared to 37.5 billion cubic feet for the three months ended June 30, 2011. Total gas production decreased as a result of a decrease of 3.5 billion net cubic feet of production related to the 2011 divestiture of Antero and the 2011 Noble Joint Venture, offset, in part, by the on-going drilling program. See Note 2—Acquisitions and Dispositions in the Notes to the Unaudited Consolidated Financial Statements for additional details on the Antero and Noble transactions.
The average sales price and average costs for all active gas operations were as follows:

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	$3.98	$5.07	$(1.09)	(21.5)%
Average Costs per thousand cubic feet sold	3.34	3.57	(0.23)	(6.4)%
Margin	$0.64	$1.50	$(0.86)	(57.3)%

Total gas division outside sales revenue was $149 million for the three months ended June 30, 2012 compared to $190 million for the three months ended June 30, 2011. The decrease was primarily due to the 21.5% reduction in average sales price. The decrease in average sales price is the result of lower general market prices for natural gas, offset, in part, by various gas swap transactions maturing in each period. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 19.1 billion cubic feet of produced gas sales volumes for the three months ended June 30, 2012 at an average price of $5.25 per thousand cubic feet. These financial hedges represented 23.1 billion cubic feet of produced gas sales volumes for the three months ended June 30, 2011 at an average price of $5.14 per thousand cubic feet.

Changes in the average cost per thousand cubic feet of gas sold were primarily related to the following items:

- Lower direct administrative, selling and other costs per unit due to decreased actual dollars due to reduced direct administrative labor and other costs.
- Lower units-of-production depreciation, depletion and amortization rates for producing properties. These rates were generally calculated using the net book value of assets divided by either proved or proved developed reserve additions. Increased proved and proved developed reserves relative to the net book value of the producing assets resulted in a lower units-of-production rate.
- Lower lifting costs that were the result of decreased road maintenance and well tending costs.

The other segment includes industrial supplies activity, terminal, river and dock service activity, income taxes and other business activities not assigned to the coal or gas segment.

At the beginning of 2012, management decided that it would no longer consider general and administrative costs on a segment by segment basis as a factor in their decision making process. These decisions include allocation of capital and individual segment profit performance results. Management also concluded that general and administrative costs would continue to be considered in results at the divisional level (total coal and total gas). In order to present financial information in a manner consistent with internal management's evaluations, the prior periods general and administrative costs have been reclassified to reflect information consistent with the current year's presentation. The total divisional results have not changed. Individual segment results within the division have been recast to reflect costs excluding general and administrative. General and administrative costs are excluded from the coal and gas unit costs above. As in the prior periods, general and administrative costs are allocated between divisions (Coal, Gas, Other) based primarily on percentage of total revenue and percentage of total projected capital expenditures. The total general and administrative costs were made up of the following items:

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Employee wages and related expenses	$14	$16	$(2)	(12.5)%
Consulting and professional services	7	9	(2)	(22.2)%
Miscellaneous	8	10	(2)	(20.0)%
Total Company General and Administrative Expenses	$29	$35	$(6)	(17.1)%

Total Company General and Administrative Expenses changed due to the following:

- Employee wages and related expenses decreased $2 million in the period-to-period comparison primarily attributable to lower salary other post-retirement benefit expenses in the period-to-period comparison. The lower expenses relate to changes in the discount rates and other assumptions and a modification to the benefit plan for certain salaried employees.

- Consulting and professional services decreased $2 million in the period-to-period comparison primarily due to a

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reduction in CONSOL Energy's advertising and promotion campaign.

- Miscellaneous general and administrative expenses decreased $2 million in the period-to-period comparison due to various corporate projects that occurred throughout both periods, none of which were individually material.

Included in both coal and gas unit costs are total Company long-term liabilities, such as other postretirement benefits (OPEB), the salary retirement plan, workers' compensation and long-term disability. These long-term liabilities costs are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. Total CONSOL Energy expense related to our actuarial calculated liabilities was $62 million for the three months ended June 30, 2012 compared to $90 million for the three months ended June 30, 2011. The decrease of $28 million for total CONSOL Energy expense was primarily due to a decrease in the discount rate assumptions used to calculate expense for benefit plans at the measurement date, which is December 31. Additionally, a part of the decrease was due to a plan modification for the salaried other post-retirement benefit plan which required a remeasurement as of March 31, 2012. See Note 3—Components of Pension and Other Postretirement Benefit Plans Net Periodic Benefit Costs and Note 4—Components of Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation Net Periodic Benefit Costs in the Notes to the Unaudited Consolidated Financial Statements for additional detail of the total Company expense decrease.

TOTAL COAL SEGMENT ANALYSIS for the three months ended June 30, 2012 compared to the three months ended June 30, 2011:

The coal segment contributed $252 million of earnings before income tax for the three months ended June 30, 2012 compared to $152 million for the three months ended June 30, 2011. Variances by the individual coal segments are discussed below.

	For the Three Months Ended June 30, 2012					Difference to Three Months Ended June 30, 2011				
	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$748	$71	$121	$2	$942	$(33)	$(47)	$(158)	$(5)	$(243)
Purchased Coal	—	—	—	3	3	—	—	—	(24)	(24)
Total Outside Sales	748	71	121	5	945	(33)	(47)	(158)	(29)	(267)
Freight Revenue	—	—	—	49	49	—	—	—	(10)	(10)
Other Income	—	1	—	180	181	(1)	(2)	—	166	163
Total Revenue and Other Income	748	72	121	234	1,175	(34)	(49)	(158)	127	(114)
Costs and Expenses:										
Total operating costs	472	40	57	42	611	(24)	(13)	(12)	(33)	(82)
Total provisions	43	3	7	40	93	(16)	(3)	(4)	18	(5)
Total direct administrative & other costs	23	2	3	42	70	(2)	(2)	(1)	(1)	(6)
Depreciation, depletion and amortization	77	8	11	4	100	1	(2)	2	(112)	(111)
Total Costs and Expenses	615	53	78	128	874	(41)	(20)	(15)	(128)	(204)
Freight Expense	—	—	—	49	49	—	—	—	(10)	(10)
Total Costs	615	53	78	177	923	(41)	(20)	(15)	(138)	(214)

Earnings (Loss) Before Income Taxes	$133	$19	$43	$57	$252	$7	$(29)	$(143)	$265	$100

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THERMAL COAL SEGMENT

The thermal coal segment contributed $133 million to total Company earnings before income tax for the three months ended June 30, 2012 compared to $126 million for the three months ended June 30, 2011. The thermal coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced Thermal Tons Sold (in millions)	12.2	13.2	(1.0)	(7.6)%
Average Sales Price Per Thermal Ton Sold	$61.47	$58.97	$2.50	4.2%
Average Operating Costs Per Thermal Ton Sold	38.76	37.49	1.27	3.4%
Average Provision Costs Per Thermal Ton Sold	3.49	4.42	(0.93)	(21.0)%
Average Direct Administrative and Other Costs Per Thermal Ton Sold	1.92	1.93	(0.01)	(0.5)%
Average Depreciation, Depletion and Amortization Costs Per Thermal Ton Sold	6.35	5.73	0.62	10.8%
Total Average Costs Per Thermal Ton Sold	50.52	49.57	0.95	1.9%
Margin Per Thermal Ton Sold	$10.95	$9.40	$1.55	16.5%

Thermal coal revenue was $748 million for the three months ended June 30, 2012 compared to $781 million for the three months ended June 30, 2011. The $33 million decrease was attributable to a 1.0 million reduction in thermal tons sold, offset, in part, by a $2.50 per ton higher average sales price. The sales ton decrease was primarily due to lower natural gas prices and a sluggish economy adversely impacting domestic coal-fired electric generation demand for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. The higher average thermal coal sales price in the 2012 period was the result of several successful re-negotiations of domestic thermal contracts whose pricing took effect on January 1, 2012. Produced thermal coal inventory was 2.0 million tons at June 30, 2012 compared to 1.6 million tons at June 30, 2011.

Other income attributable to the thermal coal segment represents earnings from our equity affiliates that operate thermal coal mines. The equity in earnings of affiliates is insignificant to the total segment activity.

Operating costs are comprised of labor, supplies, maintenance, subsidence, taxes other than income and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Operating costs related to the thermal coal segment were $472 million in the three months ended June 30, 2012 compared to $496 million in the three months ended June 30, 2011.

Changes in the average operating costs per ton for thermal coal sold were primarily related to the following items:

- Average operating costs per thermal ton sold increased due to fewer tons sold. Fixed costs are allocated over less tons, resulting in higher unit costs.
- Average operating costs per thermal ton sold increased due to the idling of the Blacksville Mine longwall during April 2012. The decrease in tonnage negatively impacted the average operating costs per thermal ton sold by approximately $1.01 per ton.
- Average operating supplies & maintenance cost per thermal ton sold increased due to the timing of major equipment overhaul costs and timing of gas well plugging expenditures in the period-to-period comparison.
- Labor and related benefits average costs per thermal ton sold increased. This was primarily due to the impact of the wage increases of $2.00 per hour worked related to the United Mine Workers of America (UMWA) collective bargaining agreement in the period-to-period comparison, offset, in part, by fewer overtime hours worked.
- Production taxes average cost per thermal ton sold increased due to the $2.50 per ton higher average sales price.
- Subsidence costs per thermal ton sold decreased due to the settlement of a previously incurred subsidence liability for an amount lower than expected.

Provision costs are comprised of the expenses related to the Company's long-term liabilities, such as other post-retirement benefits (OPEB), the salary retirement plan, workers' compensation, long-term disability and accretion on mine closing and related liabilities. With the exception of accretion expense on mine closing and related liabilities, these liabilities are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. Accretion is calculated on a mine-by-mine basis. The average provision costs attributable to the thermal coal segment were $43 million for the three months ended June 30, 2012 compared to $59 million for the three months ended June 30, 2011. The decrease in the thermal coal provision expense was primarily attributable to a decrease in discount

rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. This improvement was offset, in part, by the reduction in sales volumes which negatively impacted unit costs.

Direct administrative and other costs attributable to the thermal coal segment include selling, direct administrative costs and other allocated services which directly benefit the segment. Selling costs, excluding commission expense, are allocated to various segments based on a percentage of sales revenue attributable to each segment. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct administrative and other allocated services costs are associated directly with the coal segment of the business and are allocated to various mines based on a combination of estimated time worked and production. Direct administrative and other costs related to the thermal coal segment were $23 million for the three months ended June 30, 2012 compared to $25 million for the three months ended June 30, 2011. The decrease in total costs were primarily a result of lower commissions and demurrage expenses. This improvement was offset, in part, by the reduction in sales volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the thermal coal segment was $77 million for the three months ended June 30, 2012 compared to $76 million for the three months ended June 30, 2011. The increase was primarily due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis. These higher expenses coupled with fewer tons sold resulted in a $0.62 increase in average depreciation, depletion and amortization costs per ton sold.

HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $19 million to total Company earnings before income tax for the three months ended June 30, 2012 compared to $48 million for the three months ended June 30, 2011. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced High Vol Met Tons Sold (in millions)	1.2	1.5	(0.3)	(20.0%)
Average Sales Price Per High Vol Met Ton Sold	$59.94	$78.84	$(18.90)	(24.0%)
Average Operating Costs Per High Vol Met Ton Sold	33.66	35.08	(1.42)	(4.0%)
Average Provision Costs Per High Vol Met Ton Sold	2.74	4.18	(1.44)	(34.4%)
Average Direct Administrative and Other Costs Per High Vol Met Ton Sold	1.87	2.33	(0.46)	(19.7%)
Average Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Sold	6.46	6.36	0.10	1.6%
Total Average Costs Per High Vol Met Ton Sold	44.73	47.95	(3.22)	(6.7%)
Margin Per High Vol Met Ton Sold	$15.21	$30.89	$(15.68)	(50.8%)

High volatile metallurgical coal revenue was $71 million for the three months ended June 30, 2012 compared to $118 million for the three months ended June 30, 2011. Average sales prices for high volatile metallurgical coal decreased compared to the three months ended June 30, 2011 due to weakened global metallurgical coal demand. CONSOL Energy priced 1.1 million tons of high volatile metallurgical coal in the export market at an average sales price of $57.30 per ton for the three months ended June 30, 2012 compared to 1.4 million tons at an average price of $78.91 per ton for the three months ended June 30, 2011.

Other income attributed to the high volatile metallurgical coal segment represents earnings from our equity affiliates that operate high volatile metallurgical coal mines. The equity in earnings of affiliates is insignificant to the total segment activity.

Operating costs related to the high volatile metallurgical coal segment were $40 million for the three months ended June 30, 2012 compared to $53 million for the three months ended June 30, 2011. Changes in average operating costs per ton for high volatile metallurgical coal sold were primarily related to the following items:

- Subsidence cost per high volatile metallurgical ton sold decreased due to a settlement of a previously incurred subsidence liability for an amount lower than expected.
- Royalty cost per high volatile metallurgical ton sold decreased due to lower average realized price per ton sold.
- Average operating supplies & maintenance cost per high volatile metallurgical ton sold increased due to additional

maintenance costs for heavy equipment at surface mines, timing of longwall and belt overhauls, and increased use of pumpable cribs used for tailgate projects in the current period.

The provision expense attributable to the high volatile metallurgical coal segment was $3 million for the three months ended June 30, 2012 compared to $6 million for the three months ended June 30, 2011. The decrease in the high volatile metallurgical coal provision expense was primarily attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. This improvement was offset, in part, by the reduction in sales volumes which negatively impacted unit costs.

Direct administrative and other costs attributable to the high volatile coal segment include selling, direct administrative costs and other allocated services which directly benefit the segment. Selling costs, excluding commission expense, are allocated to various segments based on a percentage of sales revenue attributable to each segment. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct administrative and other allocated services costs are costs associated directly with the coal segment of the business and are allocated to various mines based on a combination of estimated time worked and production. Direct administrative and other costs related to the high volatile metallurgical coal segment were $2 million for the three months ended June 30, 2012 compared to $4 million for the three months ended June 30, 2011. The improvement is primarily due to decreased commissions and demurrage expenses. This improvement was offset, in part, by the reduction in sales volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the high volatile metallurgical coal segment was $8 million for the three months ended June 30, 2012 compared to $10 million for the three months ended June 30, 2011. Unit costs were increased in the period-to-period comparison due to lower volumes.

LOW VOL METALLURGICAL COAL SEGMENT

The low volatile metallurgical coal segment contributed $43 million to total Company earnings before income tax for the three months ended June 30, 2012 compared to $186 million for the three months ended June 30, 2011. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced Low Vol Met Tons Sold (in millions)	1.0	1.4	(0.4)	(28.6)%
Average Sales Price Per Low Vol Met Ton Sold	$123.71	$202.36	$(78.65)	(38.9)%
Average Operating Costs Per Low Vol Met Ton Sold	57.65	50.03	7.62	15.2%
Average Provision Costs Per Low Vol Met Ton Sold	7.59	7.26	0.33	4.5%
Average Direct Administrative and Other Costs Per Low Vol Met Ton Sold	3.41	2.76	0.65	23.6%
Average Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Sold	11.15	6.62	4.53	68.4%
Total Average Costs Per Low Vol Met Ton Sold	79.80	66.67	13.13	19.7%
Margin Per Low Vol Met Ton Sold	$43.91	$135.69	$(91.78)	(67.6)%

Low volatile metallurgical coal revenue was $121 million for the three months ended June 30, 2012 compared to $279 million for the three months ended June 30, 2011. The $158 million decrease was attributable to the 0.4 million ton decrease in sales tons and a $78.65 per ton decrease in average sales price. CONSOL Energy priced 0.8 million tons of low volatile metallurgical coal in the export market at an average sales price of $107.72 per ton for the three months ended June 30, 2012 compared to 1.1 million tons at an average price of $209.85 per ton for the three months ended June 30, 2011. Produced low volatile metallurgical coal inventory was 0.4 million tons at June 30, 2012

compared to 0.2 million tons at June 30, 2011.

Operating costs are made up of labor, supplies, maintenance, subsidence, taxes other than income and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Operating costs related to the low volatile metallurgical coal segment were $57 million for the three months ended June 30, 2012 compared to $69 million for the three months ended June 30, 2011. Changes in average operating costs per ton sold of low volatile metallurgical coal were primarily related to the following items:

- Average operating costs per low volatile ton sold primarily increased due to fewer tons sold. Fixed costs are allocated over less tons, resulting in higher unit costs.

- Average operating costs per low volatile ton sold also increased due to the idling of the Buchanan Mine longwall during April 2012. The decrease in tonnage negatively impacted the average operating costs per low volatile ton sold by approximately $12.14 per ton.
- Average gas well plugging and degasification costs increased due to an increased number of degasification wells drilled in the current period.
- Average production taxes and royalties were improved due to lower realized pricing on sales tons.

The provision expense attributable to the low volatile metallurgical coal segment was $7 million for the three months ended June 30, 2012 compared to $11 million for the three months ended June 30, 2011. The decrease in the low volatile metallurgical coal provision expense was primarily attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities. The per unit increase was due to fewer tons sold in the period-to-period comparison.

Direct administrative and other costs attributable to the low volatile coal segment include selling, direct administrative costs and other allocated services which directly benefit the segment. Selling costs, excluding commission expense, are allocated to various segments based on a percentage of sales revenue attributable to each segment. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct administrative and other allocated services costs are costs associated directly with the coal segment of the business and are allocated to various mines based on a combination of estimated time worked and production. Direct administrative and other costs related to the low volatile metallurgical coal segment were $3 million for the three months ended June 30, 2012 compared to $4 million for the three months ended June 30, 2011. The per unit increase was due to fewer tons sold in the period-to-period comparison.

Depreciation, depletion and amortization for the low volatile metallurgical coal segment was $11 million for the three months ended June 30, 2012 compared to $9 million for the three months ended June 30, 2011. The increase was primarily due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis. These increases were offset, in part, by lower total costs for units-of-production amortization due to the decreased tonnage. The decrease in sales tons increased average unit cost for depreciation, depletion and amortization due to fixed straight-line basis costs being allocated over fewer tons.

OTHER COAL SEGMENT

The other coal segment had earnings before income tax of $57 million for the three months ended June 30, 2012 compared to a loss before income tax of $208 million for the three months ended June 30, 2011. The other coal segment includes purchased coal activities, idle mine activities, coal general and administrative costs as well as various activities assigned to the coal division but not allocated to each individual mine.

Other coal segment produced coal sales include revenue from the sale of less than 0.1 million tons and 0.1 million tons for the three months ended June 30, 2012 and June 30, 2011, respectively. The primary focus of the activity at these locations is reclaiming disturbed land in accordance with the mining permit requirements after final mining has occurred. The tons sold were incidental to total Company production or sales.

Purchased coal sales consist of revenues from processing third-party coal in our preparation plants for blending purposes to meet customer coal specifications, coal purchased from third parties and sold directly to our customers and revenues from processing third-party coal in our preparation plants. The revenues were $3 million for the three months ended June 30, 2012 compared to $27 million for the three months ended June 30, 2011. The decrease was due to purchasing additional tons of third party coal in the 2011 period due to a railroad bridge outage in order to meet contractual deliveries during the outage.

Freight revenue is the amount billed to customers for transportation costs incurred. This revenue is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is offset in freight expense. Freight revenue was $49 million for the three months ended June 30, 2012 compared to $59 million for the three months ended June 30, 2011. The $10 million decrease in freight expense is due to decreased shipments on contracts

for which CONSOL Energy contractually provides transportation services.

Miscellaneous other income was $180 million for the three months ended June 30, 2012 compared to $14 million for the three months ended June 30, 2011. The increase of $166 million primarily related to the sales of non-producing assets in the Northern Powder River Basin that resulted in income of $151 million, as well as coal and surface lands in Illinois and West Virginia that resulted in income of $22 million. See Note 2—Acquisitions and Dispositions in the Notes to the Unaudited Consolidated Financial Statements for additional detail of these sales. Other revenue also includes $6 million of income from certain thermal coal contract buyouts received during the quarter. These improvements were offset, in part, by various

transactions that occurred throughout both periods, none of which were individually material.

Other coal segment total costs were $177 million for the three months ended June 30, 2012 compared to $315 million for the three months ended June 30, 2011. The decrease of $138 million was due to the following items:

	For the Three Months Ended June 30,		
	2012	2011	Variance
Abandonment of long-lived assets	$—	$115	$(115)
Purchased coal	9	34	(25)
Freight expense	49	59	(10)
Coal contract buyout	—	5	(5)
Closed and idle mines	51	32	19
Other	68	70	(2)
Total Other Coal Segment Costs	$177	$315	$(138)

- Abandonment of long-lived assets were $115 million for the three months ended June 30, 2011 as a result of the 2011 decision to permanently idle Mine 84.

- Purchased coal costs decreased approximately $25 million in the period-to-period comparison primarily due to coal purchases to fulfill various contracts during a railroad bridge outage that occurred in the 2011 period.

- Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used for the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is the amount billed to customers for transportation costs incurred. Freight expense is offset in freight revenue. Freight expense decreased $10 million primarily due to decreased shipments on contracts for which CONSOL Energy contractually provides transportation services.

- Coal contract buyouts decreased due to comparison period including the cost of buying out of a lower priced sales contract in order to sell the tons on higher priced contracts.

- Closed and idle mine costs increased approximately $19 million for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. The increase was the result of a $32 million addition to the Fola Complex reclamation liabilities in the three months ended June 30, 2012 as a result of changes in the mine plan due to new regulatory requirements, water and selenium treatment estimates, and the decision to idle mining due to market conditions. The current period Fola Complex adjustment was an increase of $24 million compared to the Fola Complex reclamation liability adjustment recognized in the three months ended June 30, 2011. Closed and idle mine costs decreased $10 million as the result of a decision to permanently abandon Mine 84 in 2011. Closed and idle mine costs increased $5 million due to other changes in the operational status of various other mines, between idled and operating throughout both periods, none of which were individually material.

- Other expenses related to the coal segment decreased $2 million in the period-to-period comparison due to various miscellaneous transactions which occurred throughout both periods, none of which were individually material.

TOTAL GAS SEGMENT ANALYSIS for the three months ended June 30, 2012 compared to the three months ended June 30, 2011:

The gas segment contributed $1 million to the total Company earnings before income tax for the three months ended June 30, 2012 compared to $28 million for the three months ended June 30, 2011.

	For the Three Months Ended June 30, 2012					Difference to Three Months Ended June 30, 2011				
	CBM	Shallow Oil & Gas	Marcellus	Other Gas	Total Gas	CBM	Shallow Oil & Gas	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$88	$34	$24	$2	$148	$(28)	$(8)	$(4)	$(1)	$(41)
Related Party	1	—	—	—	1	—	—	—	—	—
Total Outside Sales	89	34	24	2	149	(28)	(8)	(4)	(1)	(41)
Gas Royalty Interest	—	—	—	10	10	—	—	—	(6)	(6)
Purchased Gas	—	—	—	—	—	—	—	—	(1)	(1)
Other Income	—	—	—	18	18	—	—	—	15	15
Total Revenue and Other Income	89	34	24	30	177	(28)	(8)	(4)	7	(33)
Lifting	11	11	2	—	24	1	1	(2)	—	—
Ad Valorem, Severance, and Other Taxes	2	2	1	—	5	(1)	(2)	1	—	(2)
Gathering	26	5	5	1	37	2	—	1	(1)	2
Gas Direct Administrative, Selling & Other	4	4	2	2	12	(4)	(2)	(2)	3	(5)
Depreciation, Depletion and Amortization	22	14	9	2	47	(3)	(2)	1	—	(4)
General & Administration	—	—	—	9	9	—	—	—	(2)	(2)
Gas Royalty Interest	—	—	—	7	7	—	—	—	(7)	(7)
Purchased Gas	—	—	—	1	1	—	—	—	(1)	(1)
Exploration and Other Costs	—	—	—	16	16	—	—	—	15	15
Other Corporate Expenses	—	—	—	17	17	—	—	—	(1)	(1)
Interest Expense	—	—	—	1	1	—	—	—	(1)	(1)
Total Cost	65	36	19	56	176	(5)	(5)	(1)	5	(6)
Earnings Before Income Tax	$24	$(2)	$5	$(26)	$1	$(23)	$(3)	$(3)	$2	$(27)

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $24 million to the total Company earnings before income tax for the three months ended June 30, 2012 compared to $47 million for the three months ended June 30, 2011.

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced Gas CBM sales volumes (in billion cubic feet)	22.3	22.9	(0.6)	(2.6)%
Average CBM sales price per thousand cubic feet sold	$3.96	$5.12	$(1.16)	(22.7)%
Average CBM lifting costs per thousand cubic feet sold	0.45	0.42	0.03	7.1%
Average CBM ad valorem, severance, and other taxes per thousand cubic feet sold	0.11	0.14	(0.03)	(21.4)%
Average CBM gathering costs per thousand cubic feet sold	1.17	1.06	0.11	10.4%
Average CBM direct administrative, selling & other costs per thousand cubic feet sold	0.18	0.36	(0.18)	(50.0)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	0.96	1.11	(0.15)	(13.5)%
Total Average CBM costs per thousand cubic feet sold	2.87	3.09	(0.22)	(7.1)%
Average Margin for CBM	$1.09	$2.03	$(0.94)	(46.3)%

CBM sales revenues were $89 million for the three months ended June 30, 2012 compared to $117 million for the three months ended June 30, 2011. The $28 million decrease was primarily due to a 22.7% decrease in average sales price per thousand cubic feet sold, as well as a 2.6% decrease in average volumes sold. The decrease in CBM average sales price is the result of lower general market prices for natural gas, offset, in part, by various gas swap transactions maturing in each period. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 10.9 billion cubic feet of produced CBM gas sales volumes for the three months ended June 30, 2012 at an average price of $5.33 per thousand cubic feet. In the three months ended June 30, 2011, these financial hedges represented 16.8 billion cubic feet at an average price of $5.26 per thousand cubic feet. CBM sales volumes decreased 0.6 billion cubic feet for the three months ended June 30, 2012 compared to the 2011 period primarily due to normal well declines without a corresponding increase in wells drilled. Currently, the focus of the gas division is to develop the Marcellus and Utica acreage. At June 30, 2012, there were 4,482 gross CBM wells in production. At June 30, 2011, there were 4,327 gross CBM wells in production.

Total costs for the CBM segment were $65 million for the three months ended June 30, 2012 compared to $70 million for the three months ended June 30, 2011. Lower costs in the period-to-period comparison were primarily related to lower unit costs.

CBM lifting costs were $11 million in the three months ended June 30, 2012 compared to $10 million in the three months ended June 30, 2011. Higher average CBM lifting unit costs were related to increased well site maintenance due to slip repairs and increased well plugging costs, offset, in part by a prior year contract buyout that eliminated idle rig fees that were incurred in the 2011 period.

CBM ad valorem, severance and other taxes were $2 million in the three months ended June 30, 2012 compared to $3 million in the three months ended June 30, 2011. The decrease in total dollars and unit costs was primarily due to reduced severance tax expense caused by lower average gas sales prices during 2012.

CBM gathering costs were $26 million for the three months ended June 30, 2012 compared to $24 million for the three months ended June 30, 2011. The $2 million increase was due to increased direct labor associated with gathering activities.

CBM direct administrative, selling & other costs for the CBM segment were $4 million for the three months ended June 30, 2012 compared to $8 million for the three months ended June 30, 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The decrease in direct administrative, selling & other costs was primarily due to reduced direct administrative labor and other costs.

Depreciation, depletion and amortization attributable to the CBM segment was $22 million for the three months ended June 30, 2012 compared to $25 million for the three months ended June 30, 2011. There was approximately $15 million, or $0.67 per unit-of-production, of depreciation, depletion and amortization related to CBM gas and related well equipment that was reflected on a unit-of-production method of depreciation for the three months ended June 30, 2012. The production portion of depreciation, depletion and amortization was $18 million, or $0.79 per unit-of-production for the three months ended June 30, 2011. The unit-of-production rates are generally calculated using the net book value of assets divided by either proved or proved developed reserves. There was approximately $7 million, or $0.29 average per unit cost of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight line basis in the three months ended June 30, 2012. There was $7 million, or $0.32 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the three months ended June 30, 2011.

SHALLOW OIL AND GAS SEGMENT

The Shallow Oil and Gas segment had a loss before income tax of $2 million in the three months ended June 30, 2012 compared to earnings before income tax of $1 million in the three months ended June 30, 2011.

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced Gas Shallow Oil and Gas sales volumes (in billion cubic feet)	7.2	8.0	(0.8)	(10.0)%
Average Shallow Oil and Gas sales price per thousand cubic feet sold	$4.74	$5.27	$(0.53)	(10.1)%
Average Shallow Oil and Gas lifting costs per thousand cubic feet sold	1.46	1.27	0.19	15.0%
Average Shallow Oil and Gas ad valorem, severance, and other taxes per thousand cubic feet sold	0.30	0.46	(0.16)	(34.8)%
Average Shallow Oil and Gas gathering costs per thousand cubic feet sold	0.77	0.66	0.11	16.7%
Average Shallow Oil and Gas direct administrative, selling & other costs per thousand cubic feet sold	0.53	0.80	(0.27)	(33.8)%
Average Shallow Oil and Gas depreciation, depletion and amortization costs per thousand cubic feet sold	2.01	1.94	0.07	3.6%
Total Average Shallow Oil and Gas costs per thousand cubic feet sold	5.07	5.13	(0.06)	(1.2)%
Average Margin for Shallow Oil and Gas	$(0.33)	$0.14	$(0.47)	(335.7)%

Shallow Oil and Gas sales revenues were $34 million for the three months ended June 30, 2012 compared to $42 million for the three months ended June 30, 2011. The $8 million decrease was primarily due to the 10.1% decrease in average sales price per thousand cubic feet sold. Shallow Oil and Gas sales volumes also decreased 0.8 billion cubic feet for the three months ended June 30, 2012 compared to the 2011 period primarily due to normal well declines without a corresponding increase in wells drilled. Currently, the focus of the gas division is to develop the Marcellus and Utica acreage. Average sales price decreased primarily due to lower general market prices of natural gas in the period-to-period comparison. This decrease was offset, in part by the result of various gas swap transactions that matured in the three months ended June 30, 2012. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 5.4 billion cubic feet of produced Shallow Oil and Gas gas sales volumes for the three months ended June 30, 2012 at an average price of $5.25 per thousand cubic feet. In the three months ended June 30, 2011, these financial hedges represented 4.1 billion cubic feet at an average price of $4.99 per thousand cubic feet. At June 30, 2012, there were 10,018 gross Shallow Oil and Gas wells in production. At June 30, 2011, there were 9,947 gross Shallow Oil and Gas wells in

production.

Total costs for the Shallow Oil and Gas segment were $36 million for the three months ended June 30, 2012 compared to $41 million for the three months ended June 30, 2011.

Shallow Oil and Gas lifting costs were $11 million for the three months ended June 30, 2012 compared to $10 million for three months ended June 30, 2011. Lifting costs per unit increased due to increased equipment maintenance costs, increased water disposal costs and increased direct labor costs. Average lifting costs per unit were also negatively impacted by the

decrease in sales volumes.
Shallow Oil and Gas ad valorem, severance and other taxes were $2 million for the three months ended June 30, 2012 compared to $4 million for the three months ended June 30, 2011. The decrease in unit costs was primarily due to reduced severance tax expense caused by lower average gas sales prices during 2012.
Shallow Oil and Gas gathering costs were $5 million for the three months ended June 30, 2012 and 2011. Average gathering costs per unit were negatively impacted by the decrease in sales volumes.
Shallow Oil and Gas direct administrative, selling & other costs were $4 million for the three months ended June 30, 2012 compared to $6 million for the three months ended June 30, 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The $2 million decrease in the period-to-period comparison is due to Shallow Oil and Gas volumes representing a smaller proportion of total natural gas volumes.
Depreciation, depletion and amortization costs were $14 million for the three months ended June 30, 2012 compared to $16 million for the three months ended June 30, 2011. There was approximately $12 million, or $1.77 per unit-of production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended June 30, 2012. There was approximately $14 million, or $1.69 per unit-of-production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended June 30, 2011. The rate is calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. There was approximately $2 million, or $0.24 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the three months ended June 30, 2012. There was $2 million, or $0.25 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the three months ended June 30, 2011.

MARCELLUS GAS SEGMENT
The Marcellus segment contributed $5 million to the total Company earnings before income tax for the three months ended June 30, 2012 compared to $8 million for the three months ended June 30, 2011.

	For the Three Months Ended June 30,					
	2012	2011	Variance		Percent Change	
Produced Gas Marcellus sales volumes (in billion cubic feet)	7.2	6.2	1.0		16.1	%
Average Marcellus sales price per thousand cubic feet sold	$3.28	$4.59	$(1.31	)	(28.5	)%
Average Marcellus lifting costs per thousand cubic feet sold	0.28	0.63	(0.35	)	(55.6	)%
Average Marcellus ad valorem, severance, and other taxes per thousand cubic feet sold	0.13	0.05	0.08		160.0	%
Average Marcellus gathering costs per thousand cubic feet sold	0.64	0.69	(0.05	)	(7.2	)%
Average Marcellus direct administrative, selling & other costs per thousand cubic feet sold	0.27	0.52	(0.25	)	(48.1	)%
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	1.29	1.37	(0.08	)	(5.8	)%
Total Average Marcellus costs per thousand cubic feet sold	2.61	3.26	(0.65	)	(19.9	)%
Average Margin for Marcellus	$0.67	$1.33	$(0.66	)	(49.6	)%

The Marcellus segment sales revenues were $24 million for the three months ended June 30, 2012 compared to $28 million for the three months ended June 30, 2011. The decrease in Marcellus average sales price was the result of lower general market prices, offset, in part, by various gas swap transactions that matured in each period. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 2.8 billion cubic feet of produced Marcellus gas sales volumes for the three months ended June 30, 2012 at an average price of $4.95 per thousand cubic feet. These financial hedges represented 2.2 billion cubic feet of produced Marcellus gas sales volumes for the three months ended June 30, 2011 at an average price of $4.53 per thousand cubic feet.

The increased sales volumes are primarily due to additional wells coming on-line from our on-going drilling program, offset, in part, by a decrease of 3.5 billion net cubic feet of production related to the Antero divestiture and Noble joint venture. At June 30, 2012, there were 161 gross Marcellus Shale wells in production. At June 30, 2011, there were 150 gross Marcellus Shale wells in production.

Marcellus lifting costs were $2 million for the three months ended June 30, 2012 compared to $4 million for the three months ended June 301, 2011. Lifting costs per unit decreased $0.35 per thousand cubic feet sold due to decreased repairs and maintenance, well tending costs, well site maintenance and idle rig charges as a result of an unutilized rig in the 2011 period.

Marcellus ad valorem, severance and other taxes were $1 million in the period ended June 30, 2012 compared to less than $1 million in the period ended June 30, 2011. The increase in the current period per unit cost is primarily due to new legislation passed in the state of Pennsylvania (Act 13 of 2012, House Bill 1950). This legislation permits Pennsylvania counties to impose annual fees on unconventional gas wells located within Pennsylvania.

Marcellus gathering costs were $5 million for the three months ended June 30, 2012 compared to $4 million for the three months ended June 30, 2011. Marcellus gathering average unit costs decreased primarily as a result of 1.0 billion cubic feet of additional volumes sold.

Marcellus direct administrative, selling & other costs related to the Marcellus gas segment were $2 million for the three months ended June 30, 2012 compared to $4 million for the three months ended June 30, 2011. Direct administrative, selling & other costs attributable to the total gas division are allocated to the individual gas segments based on a combination of production and employee counts. The decrease in direct administrative, selling & other costs was primarily due to reduced direct administrative labor and other costs.

Depreciation, depletion and amortization costs were $9 million for the three months ended June 30, 2012 compared to $8 million for the three months ended June 30, 2011. There was approximately $8 million, or $1.14 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended June 30, 2012. There was approximately $7 million, or $1.17 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended June 30, 2011. The rate is calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. Additionally, there was $1 million, or $0.15 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis in the three months ended June 30, 2012. There was $1 million, or $0.20 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis in the three months ended June, 2011. The $0.05 decrease in unit costs related to gathering and other equipment is due to increased production volumes. Fixed costs are allocated over more volumes, resulting in lower unit costs.

OTHER GAS SEGMENT

The other gas segment includes activity not assigned to the CBM, Shallow Oil and Gas or Marcellus gas segments. This segment includes gas general and administrative costs, purchased gas activity, gas royalty interest activity, exploration and other costs, other corporate expenses, and miscellaneous operational activity not assigned to a specific gas segment.

Other gas sales volumes are primarily related to production from the Chattanooga Shale in Tennessee. Revenue from this operation was approximately $2 million for the three months ended June 30, 2012 compared to $3 million for the three months ended June 30, 2011. Total costs related to these other sales were $5 million in the 2012 period and were $7 million in the 2011 period. The decrease in costs is due to various items, none of which are individually material. A per unit analysis of the other operating costs in the Chattanooga shale is not meaningful due to the low volumes produced in the period-to-period analysis.

Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas sales revenue was $10 million for the three months ended June 30, 2012 compared to $16 million for the three months ended June 30, 2011. The changes in

market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	4.2	4.0	0.2	5.0 %
Average Sales Price Per thousand cubic feet	$2.26	$4.08	$(1.82)	(44.6)%

Purchased gas sales volumes represent volumes of gas we sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were less than $1 million for the three months ended June 30, 2012 compared to $1 million for the three months ended June 30, 2011.

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	0.3	0.3	—	— %
Average Sales Price Per thousand cubic feet	$2.39	$4.61	$(2.22)	(48.2)%

Other income was $18 million for the three months ended June 30, 2012 compared to $3 million for the three months ended June 30, 2011. The $15 million increase was due to $8 million of additional interest income relating to the notes receivable from the Noble joint venture transaction, $5 million of additional gains on dispositions of non-core acreage and equipment and a $2 million increase in earnings from equity affiliates.

General and administrative costs are allocated to the total gas segment based on percentage of total revenue and percentage of total projected capital expenditures. Costs were $9 million for the three month ended June 30, 2012 compared to $11 million for the three months ended June 30, 2011. Refer to the discussion of total general and administrative costs contained in the section "Net Income" of this quarterly report.

Royalty interest gas costs represent the costs related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas costs were $7 million for the three months ended June 30, 2012 compared to $14 million for the three months ended June 30, 2011. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	4.2	4.0	0.2	5.0 %
Average Cost Per thousand cubic feet sold	$1.69	$3.61	$(1.92)	(53.2)%

Purchased gas volumes represent volumes of gas purchased from third-party producers that we sell. Purchased gas volumes also reflect the impact of pipeline imbalances. The lower average cost per thousand cubic feet is due to overall price changes and contractual differences among customers in the period-to-period comparison. Purchased gas costs were $1 million for the three months ended June 30, 2012 and $2 million for the three months ended June 30, 2011.

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	0.3	0.3	—	— %
Average Cost Per thousand cubic feet sold	$2.19	$4.37	$(2.18)	(49.9)%

Exploration and other costs were $16 million for the three months ended June 30, 2012 compared to $1 million for the three months ended June 30, 2011.

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Lease Expiration Costs	$12	$—	$12	100.0 %
Dry Hole Costs	2	—	2	100.0 %
Exploration	2	1	1	100.0 %
Total Exploration and Other Costs	$16	$1	$15	1,500.0 %

- Lease Expiration costs increased $12 million due to various lease expirations at locations where CONSOL Energy allowed primary term leases to expire because of unfavorable drilling economics.
- Dry Hole Costs increased $2 million primarily due to a favorable settlement involving defective pipe in 2011 which reduced expenses.

- Exploration expenses increased $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Other corporate expenses were $17 million for the three months ended June 30, 2012 compared to $18 million for the three months ended June 30, 2011. The $1 million decrease in the period-to-period comparison was made up of the following items:

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Short-term incentive compensation	$7	$8	$(1)	(12.5)%
Stock-based compensation	3	4	(1)	(25.0)%
Unutilized firm transportation	4	4	—	—%
Bank fees	2	2	—	—%
Other	1	—	1	100.0%
Total Other Corporate Expenses	$17	$18	$(1)	(5.6)%

- The short-term incentive compensation program is designed to increase compensation to eligible employees when CNX Gas reaches predetermined targets for safety, environmental compliance, production, and unit costs.

- Stock-based compensation decreased $1 million in the period-to-period comparison due to various changes in share-based compensation programs, none of which were individually material.

- Unutilized firm transportation costs represent excess pipeline transportation capacity that the gas division obtained to enable gas production to flow on an uninterrupted basis as sales volumes increase. These costs remained consistent in the period-to-period comparison.

- Bank fees remained consistent in the period-to-period comparison.

- Other expenses increased $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Interest expense related to the other gas segment was $1 million for the three months ended June 30, 2012 compared to $2 million for the three months ended June 30, 2011. The $1 million decrease in interest expense in the period-to-period comparison is primarily due to lower average borrowings during the period on the CNX Gas Credit Facility.

OTHER SEGMENT ANALYSIS for the three months ended June 30, 2012 compared to the three months ended June 30, 2011:

The other segment includes activity from the sales of industrial supplies, the transportation operations and various other corporate activities that are not allocated to the coal or gas segments. The other segment had a loss before income tax of $42 million for the three months ended June 30, 2012 compared to a loss before income tax of $82 million for the three months ended June 30, 2011. The other segment also included total company income tax expense of $59 million for the three months ended June 30, 2012 compared to $21 million for the three months ended June 30, 2011.

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	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Sales—Outside	$96	$85	$11	12.9 %
Other Income	7	4	3	75.0 %
Total Revenue	103	89	14	15.7 %
Cost of Goods Sold and Other Charges	80	101	(21)	(20.8)%
Depreciation, Depletion & Amortization	7	5	2	40.0 %
Taxes Other Than Income Tax	2	3	(1)	(33.3)%
Interest Expense	56	62	(6)	(9.7)%
Total Costs	145	171	(26)	(15.2)%
Loss Before Income Tax	(42)	(82)	40	48.8 %
Income Tax	59	21	38	181.0 %
Net Loss	$(101)	$(103)	$2	1.9 %

Industrial supplies:

Total revenue from industrial supplies was $65 million for the three months ended June 30, 2012 compared to $56 million for the three months ended June 30, 2011. The increase was primarily related to higher sales volumes.

Total costs related to industrial supply sales were $64 million for the three months ended June 30, 2012 compared to $56 million for the three months ended June 30, 2011. The increase of $8 million was primarily related to higher sales volumes and various changes in inventory costs, none of which were individually material.

Transportation operations:

Total revenue from transportation operations was $34 million for the three months ended June 30, 2012 compared to $32 million for the three months ended June 30, 2011. The increase of $2 million was primarily attributable to higher per ton thru-put rates at the CNX Marine Terminal.

Total costs related to the transportation operations were $21 million for the three months ended June 30, 2012 and $22 million for the three months ended June 30, 2011. The decrease was due to various items in both periods, none of which were individually material.

Miscellaneous other:

Additional other income of $4 million was recognized for the three months ended June 30, 2012 compared to $1 million for the three months ended June 30, 2011. The $3 million increase was primarily due to the earnings from our equity affiliates that are included in the other segment.

Other corporate costs in the other segment include interest expense, bank fees and various other miscellaneous corporate charges. Total other costs were $60 million for the three months ended June 30, 2012 compared to $93 million for the three months ended June 30, 2011. Other corporate costs decreased due to the following items:

	For the Three Months Ended June 30,		
	2012	2011	Variance
Loss on extinguishment of debt	$—	$16	$(16)
Interest Expense	56	62	(6)
Evaluation fees for non-core asset dispositions	—	3	(3)
Bank Fees	3	5	(2)
Other	1	7	(6)
	$60	$93	$(33)

- On April 11, 2011, CONSOL Energy redeemed all of its outstanding $250 million, 7.875% senior secured notes due March 1, 2012 in accordance with the terms of the indenture governing these notes. The loss on extinguishment of debt was $16 million, which primarily represented the interest that would have been paid on these notes if held to

maturity.

- Interest expense decreased $6 million primarily due to an increase in capitalized interest due to higher capital expenditures for major construction projects in the current period. Interest expense also decreased due to lower borrowings on the revolving credit facilities.
- Evaluation fees for non-core asset dispositions decreased $3 million in the period-to-period comparison due to various corporate initiatives that were completed in 2011.
- Bank fees decreased $2 million due to lower borrowings on the revolving credit facilities in the period-to-period comparison.
- Other corporate items decreased $6 million due to various transactions that occurred throughout both periods, none of which were individually material.

Income Taxes:

The effective income tax rate was 27.8% in the three months ended June 30, 2012 compared to 21.2% in the three months ended June 30, 2011. The increase in the effective tax rate for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011 was attributable to the gain on sale of CONSOL Energy's non-producing Northern Powder River Basin (PRB) assets on June 29, 2012 of $151 million. The relationship between pre-tax earnings and percentage depletion also impacts the effective tax rate. See Note 5—Income Taxes of the Notes to the Condensed Consolidated Financial Statements of this Form 10-Q for additional information.

	For the Three Months Ended June 30,			
	2012	2011	Variance	Percent Change
Total Company Earnings Before Income Tax	$212	$99	$113	114.1 %
Income Tax Expense	$59	$21	$38	181.0 %
Effective Income Tax Rate	27.8 %	21.2 %	6.6 %	

Results of Operations

Six Months Ended June 30, 2012 Compared with Six Months Ended June 30, 2011

Net Income Attributable to CONSOL Energy Shareholders

CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $250 million, or $1.09 per diluted share, for the six months ended June 30, 2012. Net income attributable to CONSOL Energy shareholders was $270 million, or $1.18 per diluted share, for the six months ended June 30, 2011.

The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $415 million of earnings before income tax for the six months ended June 30, 2012 compared to $451 million for the six months ended June 30, 2011. The total coal division sold 29.6 million tons of coal produced from CONSOL Energy mines, excluding our portion of tons sold from equity affiliates, for the six months ended June 30, 2012 compared to 32.7 million tons for the six months ended June 30, 2011.

The average sales price and total costs per ton for all active coal operations were as follows:

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per ton sold	$ 67.36	$ 70.62	$ (3.26)	(4.6)%
Average Costs per ton sold	53.34	48.14	5.20	10.8 %
Margin per ton sold	$ 14.02	$ 22.48	$ (8.46)	(37.6)%

The lower average sales price per ton sold reflects a decrease in the global metallurgical coal markets. The coal division priced 6.7 million tons on the export market at an average sales price of $75.85 for the six months ended June 30, 2012 compared to 6.0 million tons at an average price of $118.20 per ton for the six months ended June 30, 2011.

Changes in the average costs per ton sold were primarily related to the following items:

- Average costs per ton sold increased due to fewer tons sold. Fixed costs are allocated over fewer sales tons, resulting in higher unit costs.
- The idle longwalls at the Blacksville mine and the Buchanan mine during March and April 2012 resulted in an increase in unit costs of approximately $1.23 per ton as the fixed costs were allocated over fewer tons.
- Average operating supplies and maintenance costs per ton sold increased due to additional equipment maintenance, timing of major equipment overhaul costs, increased fuels and lubricants and use of pumpable cribs for roof support.
- Average labor and labor related expenses per ton sold increased primarily as a result of the impact of the $2.00 per hour worked UMWA contract wage increases, offset, in part, by lower overtime.
- Average depreciation, depletion and amortization per ton sold increased due to additional assets placed into service after the 2011 period.
- Average provision costs per ton decreased due to the improvement in other postretirement benefits discussed in the long-term liabilities section below.

The total gas division includes CBM, shallow oil and gas, Marcellus and other gas. The total gas division contributed $13 million of earnings before income tax for the six months ended June 30, 2012 compared to $52 million for the six months ended June 30, 2011. Total gas production was 75.0 billion cubic feet for the six months ended June 30, 2012 compared to 73.4 billion cubic feet for the six months ended June 30, 2011. Total gas production increased primarily as a result of the on-going drilling program, offset, in part, by a 6.2 billion cubic feet decrease in production related to the Antero divestiture and Noble joint venture both of which occurred in 2011.

The average sales price and total costs for all active gas operations were as follows:

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change

Average Sales Price per thousand cubic feet sold	$4.12	$5.00	$(0.88)	(17.6)%
Average Costs per thousand cubic feet sold	3.36	3.52	(0.16)	(4.5)%
Margin per thousand cubic feet sold	$0.76	$1.48	$(0.72)	(48.6)%

Total gas division outside sales revenues were $310 million for the six months ended June 30, 2012 compared to $367 million for the six months ended June 30, 2011. The decrease was primarily due to the 17.6% reduction in average price per thousand cubic feet sold, offset, in part, by the 2.2% increase in volumes sold. The decrease in average sales price is the result of various gas swap transactions that occurred throughout both periods and lower average market prices. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 38.2 billion cubic feet of our produced gas sales volumes for the six months ended June 30, 2012 at an average price of $5.25 per thousand cubic feet. These financial hedges represented 36.1 billion cubic feet of our produced gas sales volumes for the six months ended June 30, 2011 at an average price of $5.29 per thousand cubic feet.

Changes in the average cost per thousand cubic feet of gas sold were primarily related to the following items:

- Higher volumes in the period-to-period comparison due to the on-going drilling program, offset, in part, by 6.2 billion cubic feet divested in the Noble and Antero transactions resulted in lower average costs per thousand cubic feet sold. Fixed costs are allocated over increased volumes, resulting in lower unit costs.
- Lower depreciation, depletion and amortization rates per thousand cubic feet sold due to increased sales volumes reducing the unit cost of straight line depreciation since actual dollars were consistent in the period-to-period comparison.
- Lower direct administrative, selling and other costs per thousand cubic feet sold due to increased sales volumes and decreased actual dollars due to reduced direct administrative labor and other costs.
- Gathering costs increased slightly in the period-to-period comparison due to increased transportation charges.

The other segment includes industrial supplies activity, terminal, river and dock service activity, income taxes and other business activities not assigned to the coal or gas segment.

In the six months ended June 30, 2012, management decided that it would no longer consider general and administrative costs on a segment by segment basis as a factor in their decision making process. These decisions include allocation of capital and individual segment profit performance results. Management did conclude that general and administrative costs would continue to be considered in results at the divisional level (total coal and total gas). In order to present financial information in a manner consistent with internal management's evaluations, the prior periods general and administrative costs have been reclassified to reflect information consistent with the current year's presentation. The total divisional results have not changed. Individual segment results within the division have been recast to reflect costs excluding general and administrative. General and administrative costs are excluded from the coal and gas unit costs above. As in the prior periods, general and administrative costs are allocated between divisions (Coal, Gas, Other) based primarily on percentage of total revenue and percentage of total projected capital expenditures. The total general and administrative costs were made up of the following items:

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change
Consulting and professional services	$15	$18	$(3)	(16.7)%
Employee wages and related expenses	31	32	(1)	(3.1)%
Miscellaneous	17	20	(3)	(15.0)%
Total Company General and Administrative Expenses	$63	$70	$(7)	(10.0)%

Total Company General and Administrative Expenses changed due to the following:

- Consulting and professional services decreased $3 million in the period-to-period comparison due to a reduction in CONSOL Energy's advertising and promotion campaign.
- Employee wages and related expenses decreased $1 million primarily attributable to lower salary OPEB expenses in the period-to-period comparison. The lower expenses relate to changes in the discount rates and other assumptions and a modification to the benefit plan for certain salaried employees.

- Miscellaneous general and administrative expenses decreased $3 million in the period-to-period comparison due to various transactions, none of which were individually material.

Total Company long-term liabilities, such as OPEB, the salary retirement plan, workers' compensation and long-term disability are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. Total CONSOL Energy expense related to our actuarial liabilities was $131 million for the six months ended June 30, 2012 compared to $167 million for the six months ended June 30, 2011. The decrease of $36 million for total CONSOL Energy expense was primarily due to a decrease in the discount rate assumptions used to calculate expense for benefit plans at the measurement date, which is December 31. Additionally, a part of the decrease was due to a plan modification for the salaried OPEB plan which required a remeasurement at March 31, 2012. See Note 3—Components of Pension and Other Postretirement Benefit Plans Net Periodic Benefit Costs and Note 4—Components of Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation Net Periodic Benefit Costs in the Notes to the Unaudited Consolidated Financial Statements for additional detail of the total Company expense decrease.

TOTAL COAL SEGMENT ANALYSIS for the six months ended June 30, 2012 compared to the six months ended June 30, 2011:

The coal segment contributed $415 million of earnings before income tax in the six months ended June 30, 2012 compared to $451 million in the six months ended June 30, 2011. Variances by the individual coal segments are discussed below.

	For the Six Months Ended June 30, 2012					Difference to Six Months Ended June 30, 2011				
	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$ 1,560	$ 132	$ 293	$ 6	$ 1,991	$ (23)	$ (64)	$ (223)	$ (8)	$ (318)
Purchased Coal	—	—	—	8	8	—	—	—	(25)	(25)
Total Outside Sales	1,560	132	293	14	1,999	(23)	(64)	(223)	(33)	(343)
Freight Revenue	—	—	—	99	99	—	—	—	3	3
Other Income	—	6	—	207	213	(3)	—	—	179	176
Total Revenue and Other Income	1,560	138	293	320	2,311	(26)	(64)	(223)	149	(164)
Costs and Expenses:										
Total operating costs	1,002	78	128	84	1,292	50	(4)	(14)	(39)	(7)
Total provisions	89	6	15	50	160	(22)	(3)	(4)	17	(12)
Total direct administrative & other costs	50	4	7	84	145	(3)	(2)	(1)	—	(6)
Depreciation, depletion and amortization	157	14	21	8	200	6	(1)	3	(114)	(106)
Total Costs and Expenses	1,298	102	171	226	1,797	31	(10)	(16)	(136)	(131)
Freight Expense	—	—	—	99	99	—	—	—	3	3
Total Costs	1,298	102	171	325	1,896	31	(10)	(16)	(133)	(128)
Earnings (Loss) Before Income Taxes	$ 262	$ 36	$ 122	$ (5)	$ 415	$ (57)	$ (54)	$ (207)	$ 282	$ (36)

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THERMAL COAL SEGMENT

The thermal coal segment contributed $262 million to total Company earnings before income tax for the six months ended June 30, 2012 compared to $319 million for the six months ended June 30, 2011. The thermal coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced Thermal Tons Sold (in millions)	25.3	27.2	(1.9)	(7.0)%
Average Sales Price Per Thermal Ton Sold	$61.65	$58.30	$3.35	5.7%
Average Operating Costs Per Thermal Ton Sold	$39.59	$35.05	$4.54	13.0%
Average Provision Costs Per Thermal Ton Sold	$3.52	$4.08	$(0.56)	(13.7)%
Average Direct Administrative and Other Costs Per Thermal Ton Sold	$1.98	$1.95	$0.03	1.5%
Average Depreciation, Depletion and Amortization Costs Per Thermal Ton Sold	$6.23	$5.55	$0.68	12.3%
Total Average Costs Per Thermal Ton Sold	$51.32	$46.63	$4.69	10.1%
Margin Per Thermal Ton Sold	$10.33	$11.67	$(1.34)	(11.5)%

Thermal coal revenue was $1,560 million for the six months ended June 30, 2012 compared to $1,583 million for the six months ended June 30, 2011. The $23 million decrease was attributable to 1.9 million less tons sold offset in part by a $3.35 per ton higher average sales prices. The higher average thermal coal sales price in the 2012 period was the result of several successful renegotiations of domestic thermal contracts whose pricing took effect on January 1, 2012. Also, 3.3 million tons of thermal coal was priced on the export market at an average sales price of $57.12 per ton for the six months ended June 30, 2012 compared to 1.2 million tons at an average price of $67.50 per ton for the six months ended June 30, 2011.

Other income attributable to the thermal coal segment represents earnings from our equity affiliates that operate thermal coal mines. The equity in earnings of affiliates is insignificant to the total segment activity.

Operating costs are comprised of labor, supplies, maintenance, subsidence, taxes other than income and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Operating costs related to the thermal coal segment were $1,002 million for the six months ended June 30, 2012 compared to $952 million for the six months ended June 30, 2011. Operating costs related to the thermal coal segment increased primarily due to higher average costs per ton sold coupled with lower volumes sold.

Changes in the average operating costs per ton for thermal coal sold were primarily related to the following items:

- Average operating costs per thermal ton sold increased due to fewer tons sold. Fixed costs are allocated over less tons, resulting in higher unit costs.
- Average operating costs per thermal ton sold increased due to the idling of the Blacksville Mine longwall during March and April 2012. The decrease in tonnage negatively impacted the average operating costs per thermal ton sold by approximately $1.01 per ton.
- Average operating supplies & maintenance cost per thermal ton sold increased due to the timing of major equipment overhaul costs and timing of gas well plugging expenditures in the period-to-period comparison.
- Labor and related benefits increased per thermal ton sold due to higher costs and lower volumes sold. This was primarily due to the impact of the wage increases of $2.00 per hour worked related to the new collective bargaining agreement in the period-to-period comparison, offset, in part, by fewer overtime hours worked.

Provision costs are made up of the expenses related to the Company's long-term liabilities, such as OPEB, the salary retirement plan, workers' compensation, and long-term disability and accretion on the mine closing and related liabilities. With the exception of accretion expense on mine closing and related liabilities, these liabilities are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on

active employee counts or active salary dollars. Accretion is calculated on a mine-by-mine basis. The average provision costs attributable to the thermal coal segment were $89 million for the six months ended June 30, 2012 compared to $111 million for the six months ended June 30, 2011. The decrease in thermal coal provision expense was attributable to the total Company decrease in long-term liability expense due to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried OPEB plan. Thermal coal accretion expense related to mine closing and related liabilities increased approximately $1 million due to the results of the annual engineering survey adjustments and due to various changes in the related liability, none of which were

individually material. These decreases were offset, in part, by lower thermal coal tons sold.

Direct administrative and other costs attributable to the thermal coal segment include selling, direct administrative costs and other allocated services which directly benefit the segment. Selling, excluding commission expense, are allocated to various segments on a combination of estimated time worked by various support groups and operating costs incurred at the mine. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct administrative costs are associated directly with the coal segment of the business and are allocated to various mines based on a combination of estimated time worked and production. Direct administrative and other costs related to the thermal coal segment were $50 million for the six months ended June 30, 2012 compared to $53 million for the six months ended June 30, 2011. The total cost decrease attributable to the thermal coal segment was primarily attributable to lower selling expenses due to lower commission expenses and lower demurrage charges. The increase in units costs in the current period is attributable to lower thermal tons sold.

Depreciation, depletion and amortization for the thermal coal segment was $157 million for the six months ended June 30, 2012 compared to $151 million for the six months ended June 30, 2011. The increase was primarily due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis. The increase was also due to higher units-of-production rates for thermal coal mines due to additional air shafts being placed into service after the 2011 period which had a higher unit rate than historical shafts put into service. These higher expenses, coupled in part with lower sales tons, resulted in an $0.68 increase in average costs per ton sold.

HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $36 million to total Company earnings before income tax for the six months ended June 30, 2012 compared to $90 million for the six months ended June 30, 2011. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced High Vol Met Tons Sold (in millions)	2.2	2.5	(0.3)	(12.0%)
Average Sales Price Per High Vol Met Ton Sold	$60.95	$77.37	$(16.42)	(21.2%)
Average Operating Costs Per High Vol Met Ton Sold	36.27	32.37	3.90	12.0%
Average Provision Costs Per High Vol Met Ton Sold	2.88	3.68	(0.80)	(21.7%)
Average Direct Administrative and Other Costs Per High Vol Met Ton Sold	2.00	2.21	(0.21)	(9.5%)
Average Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Sold	6.26	5.86	0.40	6.8%
Total Average Costs Per High Vol Met Ton Sold	47.41	44.12	3.29	7.5%
Margin Per High Vol Met Ton Sold	$13.54	$33.25	$(19.71)	(59.3%)

High volatile metallurgical coal revenue was $132 million for the six months ended June 30, 2012 compared to $196 million for the six months ended June 30, 2011. Average sales prices for high volatile metallurgical coal decreased in a period-to-period comparison due to weakening in global metallurgical coal demand. CONSOL Energy priced 1.9 million tons of high volatile metallurgical coal in the export market at an average sales price of $58.15 per ton for the six months ended June 30, 2012 compared to 2.5 million tons at an average price of $77.37 per ton for the six months ended June 30, 2011.

Other income attributed to the high volatile metallurgical coal segment represents earnings from our equity affiliates that operate high volatile metallurgical coal mines. The equity in earnings of affiliates is insignificant to the total segment activity.

Operating costs related to the high volatile metallurgical coal segment were $78 million for the six months ended June 30, 2012 compared to $82 million for the six months ended June 30, 2011. Operating costs related to the high volatile metallurgical coal segment decreased primarily due to lower volumes sold, offset, in part, by higher average operating costs.

Changes in average operating costs per ton for high volatile metallurgical coal sold were primarily related to the following items:

- Average operating supplies & maintenance cost per high volatile metallurgical ton sold increased due to additional

maintenance costs for heavy equipment at surface mines, timing of longwall and belt overhauls, and increased use of pumpable cribs used for tailgate projects in the current period.

- Average coal preparation costs per ton sold decreased due to fewer maintenance projects completed at preparation plants in the period-to-period comparison.
- Royalty cost per high volatile metallurgical ton sold decreased due to lower average realized price per ton sold.

The provision expense attributable to the high volatile metallurgical coal segment was $6 million for the six months ended June 30, 2012 compared to $9 million for the six months ended June 30, 2011. The decrease in the high volatile metallurgical coal provision expense was attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. The per unit improvement was offset, in part, by lower tons sold in the period-to-period comparison.
Direct administrative and other costs attributable to the high volatile metallurgical coal segment include selling and direct administrative costs. Selling, excluding commission expense, are allocated to various segments on a combination of estimated time worked by various support groups and operating costs incurred at the mine. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct administrative costs are associated directly with the coal segment of the business and are allocated to various mines based on a combination of estimated time worked and production. Direct administrative and other costs related to the high volatile metallurgical coal segment were $4 million for the six months ended June 30, 2012 compared to $6 million for the six months ended June 30, 2011. The total cost decrease attributable to the high volatile coal segment was primarily attributable to lower selling expenses due to lower commission expenses and lower demurrage charges.

Depreciation, depletion and amortization for the high volatile metallurgical coal segment was $14 million for the six months ended June 30, 2012 compared to $15 million for the six months ended June 30, 2011. The decrease was primarily due to equipment and infrastructure utilized on other products in the period-to-period comparison. This increase in unit costs per ton sold was a result of lower high volatile metallurgical tons sold which increased the unit cost per ton impact.

LOW VOL METALLURGICAL COAL SEGMENT
The low volatile metallurgical coal segment contributed $122 million to total Company earnings before income tax in the six months ended June 30, 2012 compared to $329 million in the six months ended June 30, 2011. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced Low Vol Met Tons Sold (in millions)	2.0	2.8	(0.8)	(28.6)%
Average Sales Price Per Low Vol Met Ton Sold	$146.40	$183.71	$(37.31)	(20.3)%
Average Operating Costs Per Low Vol Met Ton Sold	63.83	50.63	13.20	26.1%
Average Provision Costs Per Low Vol Met Ton Sold	7.60	6.59	1.01	15.3%
Average Direct Administrative and Other Costs Per Low Vol Met Ton Sold	3.65	2.77	0.88	31.8%
Average Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Sold	10.34	6.32	4.02	63.6%
Total Average Costs Per Low Vol Met Ton Sold	85.42	66.31	19.11	28.8%
Margin Per Low Vol Met Ton Sold	$60.98	$117.40	$(56.42)	(48.1)%

Low volatile metallurgical coal revenue was $293 million for the six months ended June 30, 2012 compared to $516 million for the six months ended June 30, 2011. The $223 million decrease was attributable to a $37.31 per ton lower average sales price. Average sales prices for low volatile metallurgical coal decreased in the period-to-period

comparison due to weakening in global metallurgical coal demand. For the 2012 period, 1.6 million tons of low volatile metallurgical coal was priced on the export market at an average price of $136.32 per ton compared to 2.3 million tons at an average price of $187.88 per ton for the 2011 period.

Operating costs are made up of labor, supplies, maintenance, subsidence, taxes other than income and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Operating costs related to the low volatile metallurgical coal segment were $128

million for the six months ended June 30, 2012 compared to $142 million for the six months ended June 30, 2011. Operating costs related to the low volatile metallurgical coal segment decreased primarily due to lower volumes sold, offset, in part, by higher average operating costs per ton sold.

Changes in the average operating costs per ton for low volatile metallurgical coal sold were primarily related to the following items:

- Average operating costs per low volatile metallurgical tons sold increased due to fewer tons sold. Fixed costs are then allocated over less tons, thereby increasing unit costs.
- Average operating costs per low volatile ton sold increased due to the idling of the Buchanan Mine longwall during March and April 2012. The decrease in tonnage negatively impacted the average operating costs per low volatile ton sold by approximately $14.07 per ton.
- Average operating supplies and maintenance costs per low volatile ton sold increased due to increased equipment maintenance for belts and continuous mining equipment and increased contractor services.
- Labor and related benefits were impaired on a cost per ton sold basis due to lower volumes sold. Labor and related benefit dollars spent were consistent in the 2012 period compared to the 2011 period.
- Preparation plant and power average cost per ton sold were impaired primarily due to lower tons sold.
- Royalty cost per low volatile ton sold decreased due to the lower average sales price per ton sold.

The provision expense attributable to the low volatile metallurgical coal segment was $15 million for the six months ended June 30, 2012 compared to $19 million for the six months ended June 30, 2011. The decrease in the low volatile metallurgical coal provision expense was primarily attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. The per unit increase was due to fewer tons sold in the period-to-period comparison.

Direct administrative and other costs attributable to the low volatile metallurgical coal segment include selling, direct administrative costs and water treatment expenses generated from the reverse osmosis plant. Selling, excluding commission expense and water treatment expense, are allocated to various segments on a combination of estimated time worked by various support groups and operating costs incurred at the mine. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct administrative costs are associated directly with the coal segment of the business and are allocated to various mines based on a combination of estimated time worked and production. Direct administrative and other costs related to the low volatile metallurgical coal segment were $7 million for the six months ended June 30, 2012 compared to $8 million for the six months ended June 30, 2011. The cost decrease related to the low volatile metallurgical coal segment was attributable to lower selling expenses due to lower commissions and demurrage expenses. Also, a reverse osmosis plant was completed and placed into service near the Buchanan Mine in the six months ended June 30, 2011. Active mine water discharge is being treated by this facility and the costs of these services are charged to the mine based on gallons of water treated. Currently, the Buchanan Mine is the only facility using the plant. The increased cost of the reverse osmosis plant is due to additional operating days in a period-to-period comparison. The net decrease in expense was offset, in part, by lower volumes of low volatile metallurgical coal sold.

Depreciation, depletion and amortization for the low volatile metallurgical coal segment was $21 million for the six months ended June 30, 2012 compared to $18 million for the six months ended June 30, 2011. The increase was primarily due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis. These increases in average costs per ton sold were also due to lower low volatile metallurgical tons sold which increased the unit cost per ton impact.

OTHER COAL SEGMENT

The other coal segment had a loss before income tax of $5 million for the six months ended June 30, 2012 compared to a loss before income tax of $287 million for the six months ended June 30, 2011. The other coal segment includes purchased coal activities, idle mine activities, as well as various activities assigned to the coal segment but not allocated to each individual mine.

Other coal segment produced coal sales includes revenue from the sale of 0.1 million tons of coal which was recovered during the reclamation process at idled facilities for the six months ended June 30, 2012 and 0.2 million tons for the six months ended June 30, 2011. The primary focus of the activity at these locations is reclaiming disturbed land in accordance with the mining permit requirements after final mining has occurred. The tons sold are incidental to total Company production or sales.

Purchased coal sales consist of revenues from processing third-party coal in our preparation plants for blending purposes

to meet customer coal specifications, coal purchased from third parties and sold directly to our customers and revenues from processing third-party coal in our preparation plants. The revenues were $8 million for the six months ended June 30, 2012 compared to $33 million for the six months ended June 30, 2011. The decrease was due to the purchase of additional tons of third party coal in the 2011 period due to a railroad bridge outage in order to meet contractual deliveries during the outage.
Freight revenue is the amount billed to customers for transportation costs incurred. This revenue is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is offset by freight expense. Freight revenue was $99 million for the six months ended June 30, 2011 compared to $96 million for the six months ended June 30, 2011.
Miscellaneous other income was $207 million for the six months ended June 30, 2012 compared to $28 million for the six months ended June 30, 2011. The increase of $179 million is primarily related to sales of non-producing assets in the Northern Powder River Basin that resulted in income of $151 million, as well as coal and surface lands in Illinois and West Virginia that resulted in income of $22 million. See Note 2—Acquisitions and Dispositions in the Notes to the Unaudited Consolidated Financial Statements for additional detail of these sales. Other revenue also includes $6 million of income from certain thermal coal contract buyouts received in the six months ended June 30, 2012.
Other coal segment total costs were $325 million for the six months ended June 30, 2011 compared to $458 million for the six months ended June 30, 2011. The decrease of $133 million was due to the following items:

	For the six months ended June 30,			
	2012	2011	Variance	
Abandonment of long-lived assets	$—	$115	$(115	)
Purchased Coal	21	47	(26	)
Coal contract buyout	—	5	(5	)
Freight expense	99	96	3	
Closed and idle mines	72	59	13	
Other	133	136	(3	)
Total Other Coal Segment Costs	$325	$458	$(133	)

- Abandonment of long-lived assets were $115 million for the six months ended June 30, 2011 as a result of the 2011 decision to permanently idle Mine 84.
- Purchased coal costs decreased approximately $26 million in the period-to-period comparison primarily due to coal purchases to fulfill various contracts during a railroad bridge outage that occurred in the 2011 period.
- Coal contract buyout costs decreased $5 million as a result of a lower priced coal sales contract being bought out in 2011 in order to sell the tons on a higher priced contract.
- Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is the amount billed to customers for transportation costs incurred. Freight expense is offset by freight revenue.
- Closed and idle mine costs increased approximately $13 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. The increase was the result of a $32 million addition to the Fola Complex reclamation liabilities in the six months ended June 30, 2012 as a result of changes in the mine plan due to new regulatory requirements, water and selenium treatment estimates, and the decision to idle mining due to market conditions. The current period Fola Complex adjustment was an increase of $24 million compared to the Fola Complex reclamation liability adjustment recognized in the six months ended June 30, 2011. Closed and idle mine costs decreased $10 million as the result of a 2011 decision to permanently abandon Mine 84 in 2011. Closed and idle mine costs decreased $1 million due to other changes in the operational status of various other mines, between idled and operating throughout both periods, none of which were individually material.
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Other expenses related to the coal segment decreased $3 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011 due to various transactions that occurred throughout both periods, none of which were individually material.

TOTAL GAS SEGMENT ANALYSIS for the six months ended June 30, 2012 compared to the six months ended June 30, 2011:

The gas segment contributed $13 million to earnings before income tax in the six months ended June 30, 2012 compared to $52 million in the six months ended June 30, 2011.

	For the Six Months Ended June 30, 2012					Difference to Six Months Ended June 30, 2011				
	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$187	$69	$48	$5	$309	$(42)	$(12)	$—	$(2)	$(56)
Related Party	1	—	—	—	1	(1)	—	—	—	(1)
Total Outside Sales	188	69	48	5	310	(43)	(12)	—	(2)	(57)
Gas Royalty Interest	—	—	—	22	22	—	—	—	(13)	(13)
Purchased Gas	—	—	—	1	1	—	—	—	(1)	(1)
Other Income	—	—	—	34	34	—	—	—	29	29
Total Revenue and Other Income	188	69	48	62	367	(43)	(12)	—	13	(42)
Lifting	19	21	6	1	47	—	—	—	—	—
Ad Valorem, Severance, and Other Taxes	5	5	2	—	12	(1)	—	2	(1)	—
Gathering	51	11	9	1	72	4	(1)	2	(1)	4
Gas Direct Administrative, Selling & Other	9	8	5	3	25	(7)	(4)	—	5	(6)
Depreciation, Depletion and Amortization	43	30	18	6	97	(6)	(3)	4	1	(4)
General & Administration	—	—	—	19	19	—	—	—	(3)	(3)
Gas Royalty Interest	—	—	—	17	17	—	—	—	(14)	(14)
Purchased Gas	—	—	—	1	1	—	—	—	(2)	(2)
Exploration and Other Costs	—	—	—	21	21	—	—	—	17	17
Other Corporate Expenses	—	—	—	40	40	—	—	—	11	11
Interest Expense	—	—	—	3	3	—	—	—	(2)	(2)
Total Cost	127	75	40	112	354	(10)	(8)	8	11	1
Earnings Before Noncontrolling Interest and Income Tax	61	(6)	8	(50)	13	(33)	(4)	(8)	2	(43)
Noncontrolling Interest	—	—	—	—	—	—	—	—	(4)	(4)
Earnings Before Income Tax	$61	$(6)	$8	$(50)	$13	$(33)	$(4)	$(8)	$6	$(39)

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $61 million to the total Company earnings before income tax for the six months ended June 30, 2012 compared to $94 million for the six months ended June 30, 2011.

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced Gas CBM sales volumes (in billion cubic feet)	45.1	45.3	(0.2)	(0.4)%
Average CBM sales price per thousand cubic feet sold	$4.18	$5.12	$(0.94)	(18.4)%
Average CBM lifting costs per thousand cubic feet sold	0.43	0.43	—	—%
Average CBM ad valorem, severance, and other taxes per thousand cubic feet sold	0.12	0.14	(0.02)	(14.3)%
Average CBM gathering costs per thousand cubic feet sold	1.12	1.04	0.08	7.7%
Average CBM direct administrative, selling & other costs per thousand cubic feet sold	0.21	0.35	(0.14)	(40.0)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	0.95	1.09	(0.14)	(12.8)%
Total Average CBM costs per thousand cubic feet sold	2.83	3.05	(0.22)	(7.2)%
Average Margin for CBM	$1.35	$2.07	$(0.72)	(34.8)%

CBM sales revenues were $188 million in the six months ended June 30, 2012 compared to $231 million for the six months ended June 30, 2011. The $43 million decrease was primarily due to a 18.4% decrease in average sales price per thousand cubic feet sold and a 0.4% decrease in average volumes sold. The decrease in CBM average sales price is the result of various gas swap transactions that matured in each period and lower average market prices. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 23.1 billion cubic feet of our produced CBM gas sales volumes for the six months ended June 30, 2012 at an average price of $5.33 per thousand cubic feet. For the six months ended June 30, 2011, these financial hedges represented 28.6 billion cubic feet at an average price of $5.26 per thousand cubic feet. CBM sales volumes decreased 0.2 billion cubic feet for the six months ended June 30, 2012 compared to the 2011 period primarily due to normal well declines without a corresponding increase in wells drilled. Currently, the focus of the gas division is to develop the Marcellus and Utica acreage. At June 30, 2012, there were 4,482 gross CBM wells in production. At June 30, 2011, there were 4,327 gross CBM wells in production.

Total costs for the CBM segment were $127 million for the six months ended June 30, 2012 compared to $137 million for the six months ended June 30, 2011. Lower costs in the period-to-period comparison are primarily related to lower unit costs.

CBM lifting costs were $19 million for the six months ended June 30, 2012 and 2011. Lifting costs remained consistent in the period-to-period comparison. Decreased volumes sold did not significantly impact lifting costs per unit which also remained consistent at $0.43 per thousand cubic feet sold.

CBM ad valorem, severance and other taxes were $5 million for the six months ended June 30, 2012 compared to $6 million for the six months ended June 30, 2011. The decrease in unit costs was primarily due to reduced severance tax expense caused by lower average gas sales prices during 2012.

CBM gathering costs were $51 million for the six months ended June 30, 2012 compared to $47 million for the six months ended June 30, 2011. Higher average CBM gathering unit costs are related to higher transportation costs, compressor maintenance, equipment lease expenses and lower volumes sold in the period-to-period comparison.

CBM direct administrative, selling & other costs for the CBM segment were $9 million for the six months ended June 30, 2012 compared to $16 million for the six months ended June 30, 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The decrease in direct administrative, selling & other costs was primarily due to reduced direct

administrative labor and other costs.
Depreciation, depletion and amortization attributable to the CBM segment was $43 million for the six months ended June 30, 2012 compared to $49 million for the six months ended June 30, 2011. There was approximately $30 million, or $0.66 per

unit-of-production, of depreciation, depletion and amortization related to CBM gas and related well equipment that was reflected on a units-of-production method of depreciation in the six months ended June 30, 2012. The production portion of depreciation, depletion and amortization was $35 million, or $0.79 per unit-of-production in the six months ended June 30, 2011. The CBM unit-of-production rate decreased due to revised rates which were generally calculated using the net book value of assets divided by either proved or proved developed reserve additions. There was approximately $13 million, or $0.29 average per unit cost of depreciation, depletion and amortization relating to gathering and other equipment reflected on a straight line basis for the six months ended June 30, 2012. The non-production related depreciation, depletion and amortization was $14 million, or $0.30 per thousand cubic feet for the six months ended June 30, 2011.

SHALLOW OIL AND GAS SEGMENT

The shallow oil and gas segment had a loss before income tax of $6 million for the six months ended June 30, 2012 compared to a loss before income tax of $2 million for the six months ended June 30, 2011.

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced Gas Shallow Oil and Gas sales volumes (in billion cubic feet)	14.8	16.2	(1.4)	(8.6)%
Average Shallow Oil and Gas sales price per thousand cubic feet sold	$4.63	$5.01	$(0.38)	(7.6)%
Average Shallow Oil and Gas lifting costs per thousand cubic feet sold	1.39	1.21	0.18	14.9%
Average Shallow Oil and Gas ad valorem, severance, and other taxes per thousand cubic feet sold	0.32	0.41	(0.09)	(22.0)%
Average Shallow Oil and Gas gathering costs per thousand cubic feet sold	0.78	0.76	0.02	2.6%
Average Shallow Oil and Gas direct administrative, selling & other costs per thousand cubic feet sold	0.56	0.75	(0.19)	(25.3)%
Average Shallow Oil and Gas depreciation, depletion and amortization costs per thousand cubic feet sold	1.99	2.01	(0.02)	(1.0)%
Total Average Shallow Oil and Gas costs per thousand cubic feet sold	5.04	5.14	(0.10)	(1.9)%
Average Margin for Shallow Oil and Gas	$(0.41)	$(0.13)	$(0.28)	215.4%

Shallow oil and gas sales revenues were $69 million for the six months ended June 30, 2012 compared to $81 million for the six months ended June 30, 2011. The $12 million decrease was primarily due to the 8.6% decrease in volumes sold as well as the 7.6% decrease in average sales price. The decrease in shallow oil and gas sales price is the result of various gas swap transactions that matured in the six months ended June 30, 2012. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 9.5 billion cubic feet of our produced shallow oil and gas sales volumes for the six months ended June 30, 2012 at an average price of $5.23 per thousand cubic feet. For the six months ended June 30, 2011, these financial hedges represented 4.0 billion cubic feet at an average price of $4.99 per thousand cubic feet. At June 30, 2012, there were 10,018 gross Shallow Oil and Gas wells in production. At June 30, 2011, there were 9,947 gross Shallow Oil and Gas wells in production.

Total costs for the shallow oil and gas segment were $75 million for the six months ended June 30, 2012 compared to $83 million for the six months ended June 30, 2011. The decrease is attributable to decreased variable costs associated with the lower sales volumes and lower average unit costs.

Shallow Oil and Gas lifting costs were $21 million for the six months ended June 30, 2012 and 2011. Costs were consistent in the period-to-period comparison. The increase in unit costs was due to lower sales volumes.

Shallow Oil and Gas ad valorem, severance and other taxes were $5 million for the six months ended June 30, 2012 and 2011. The decrease in unit costs was primarily due to reduced severance tax expense caused by lower average gas sales prices during 2012.
Shallow Oil and Gas gathering costs were $11 million for the six months ended June 30, 2012 compared to $12 million

for the six months ended June 30, 2011. Gathering costs decreased primarily due to lower compressor maintenance and lower equipment lease expenses in the period-to-period comparison
Shallow Oil and Gas direct administrative, selling & other costs were $8 million for the six months ended June 30, 2012 compared to $12 million for the six months ended June 30, 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The $4 million decrease in the period-to-period comparison is due to Shallow Oil and Gas volumes representing a smaller proportion of total natural gas volumes.
Depreciation, depletion and amortization costs were $30 million for the six months ended June 30, 2012 compared to $33 million for the six months ended June 30, 2011. There was approximately $26 million, or $1.74 per unit-of production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the six months ended June 30, 2012. There was approximately $29 million, or $1.78 per unit-of-production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the six months ended June 30, 2011. The rate is calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. There was approximately $4 million, or $0.25 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the six months ended June 30, 2012. There was $4 million, or $0.23 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the six months ended June 30, 2011.

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $8 million to the total Company earnings before income tax for the six months ended June 30, 2012 compared to $16 million for the six months ended June 30, 2011.

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change
Produced Gas Marcellus sales volumes (in billion cubic feet)	13.9	11.0	2.9	26.4 %
Average Marcellus sales price per thousand cubic feet sold	$3.41	$4.48	$(1.07)	(23.9)%
Average Marcellus lifting costs per thousand cubic feet sold	0.43	0.51	(0.08)	(15.7)%
Average Marcellus ad valorem, severance, and other taxes per thousand cubic feet sold	0.14	0.05	0.09	180.0 %
Average Marcellus gathering costs per thousand cubic feet sold	0.61	0.64	(0.03)	(4.7)%
Average Marcellus direct administrative, selling & other costs per thousand cubic feet sold	0.34	0.51	(0.17)	(33.3)%
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	1.31	1.32	(0.01)	(0.8)%
Total Average Marcellus costs per thousand cubic feet sold	2.83	3.03	(0.20)	(6.6)%
Average Margin for Marcellus	$0.58	$1.45	$(0.87)	(60.0)%

The Marcellus segment sales revenues were $48 million for the six months ended June 30, 2012 and 2011. Sales revenues remained consistent due to a 26.4% increase in average volumes sold, offset by a 23.9% decrease in average sales price per thousand cubic feet sold. The decrease in Marcellus average sales price was the result of the decline in general market prices. These decreases were offset, in part, by various gas swap transactions that matured in the six months ended June 30, 2012. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 5.5 billion cubic feet of our produced Marcellus gas sales volumes for the six months ended June 30, 2012 at an average price of $4.97 per

thousand cubic feet. For the six months ended June 30, 2011, these financial hedges represented 3.5 billion cubic feet at an average price of $4.53 per thousand cubic feet. The increase in sales volumes is primarily due to additional wells coming on-line from our on-going drilling program, offset, in part, by a 6.2 billion cubic feet decrease in production related to the Antero divestiture and Noble joint venture. At June 30, 2012, there were 161 gross Marcellus Shale wells in production. At June 30, 2011, there were 150 gross Marcellus Shale wells in production.

Marcellus lifting costs were $6 million for the six months ended June 30, 2012 and 2011. Costs were consistent in the period-to-period comparison. Unit costs decreased due to additional sales volumes.

Marcellus ad valorem, severance and other taxes were $2 million for the six months ended June 30, 2012 compared to less than $1 million for the six months ended June 30, 2011. The increase in the current period per unit cost is primarily due to new legislation passed in the state of Pennsylvania (Act 13 of 2012, House Bill 1950). This legislation permits Pennsylvania counties to impose annual fees on unconventional gas wells located within Pennsylvania.
Marcellus gathering costs were $9 million for the six months ended June 30, 2012 compared to $7 million for the six months ended June 30, 2011. Average gathering costs decreased $0.03 per unit primarily due to the 2.9 billion cubic feet of additional volumes sold.
Marcellus direct administrative, selling & other costs were $5 million for the six months ended June 30, 2012 and 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The decrease in direct administrative, selling & other costs was primarily due to reduced direct administrative labor and other costs.
Depreciation, depletion and amortization costs were $18 million for the six months ended June 30, 2012 compared to $14 million for the six months ended June 30, 2011. There was approximately $16 million, or $1.17 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation in the six months ended June 30, 2012. There was approximately $11 million, or $1.09 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation for the six months ended June 30, 2011. The rate was calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. There was approximately $2 million, or $0.14 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis for the six months ended June 30, 2012. There was $3 million, or $0.23 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the six months ended June 30, 2011.

OTHER GAS SEGMENT
The other gas segment includes activity not assigned to the CBM, shallow oil and gas or Marcellus gas segments. This segment includes purchased gas activity, gas royalty interest activity, exploration and other costs, other corporate expenses, and miscellaneous operational activity not assigned to a specific gas segment.
Other gas sales volumes are primarily related to production from the Chattanooga Shale in Tennessee. Revenue from this operation was approximately $5 million for the six months ended June 30, 2012 and $7 million for the six months ended June 30, 2011. Total costs related to these other sales were $11 million for the 2012 period and were $7 million for the 2011 period. The increase in costs in the period-to-period comparison were primarily attributable to depreciation, depletion and amortization and increased direct administrative, selling & other costs. Increased direct administrative, selling and other costs is primarily related to higher proportional allocation relating to Utica operating area during 2012. Higher depreciation, depletion and amortization was due to higher volumes produced and higher unit of production rates. The increase in the rate was related to a higher proportion of capital assets placed in service versus the proportion of proved developed reserve additions. A per unit analysis of the other operating costs in Chattanooga is not meaningful due to the low volumes produced in the period-to-period analysis.
Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas sales revenue was $22 million for the six months ended June 30, 2012 compared to $35 million for the six months ended June 30, 2011. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Six Months Ended June 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	8.3	8.3	—	— %
Average Sales Price Per thousand cubic feet	$2.61	$4.24	$(1.63)	(38.4)%

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $1 million for the six months ended June 30, 2012 and $2 million for the six months ended June 30, 2011.

For the Six Months Ended June 30,