CONSOL Energy Inc
Form 10-Q
November 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 September 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 October 16, 2012

Common stock, $0.01 par value	227,780,531

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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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Sales—Outside	$1,084,041	$1,421,689	$3,584,805	$4,293,167
Sales—Gas Royalty Interests	12,968	17,083	34,707	52,191
Sales—Purchased Gas	953	1,155	2,443	3,297
Freight—Outside	27,430	59,871	126,195	156,311
Other Income	34,697	21,931	293,196	70,068
Total Revenue and Other Income	1,160,089	1,521,729	4,041,346	4,575,034
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	827,530	879,268	2,588,460	2,620,376
Gas Royalty Interests Costs	10,543	15,409	27,916	46,582
Purchased Gas Costs	737	398	2,123	2,850
Freight Expense	27,430	59,871	126,195	156,122
Selling, General and Administrative Expenses	36,681	46,692	109,412	130,311
Depreciation, Depletion and Amortization	153,877	159,750	463,048	466,612
Interest Expense	54,075	58,884	168,788	189,963
Taxes Other Than Income	80,587	85,790	256,543	265,121
Abandonment of Long-Lived Assets	—	338	—	115,817
Loss on Debt Extinguishment	—	—	—	16,090
Transaction and Financing Fees	—	14,907	—	14,907
Total Costs	1,191,460	1,321,307	3,742,485	4,024,751
(Loss) Earnings Before Income Taxes	(31,371)	200,422	298,861	550,283
Income Taxes (Benefit) Expense	(19,898)	33,093	60,428	113,421
Net (Loss) Income	(11,473)	167,329	238,433	436,862
Add: Net Loss Attributable to Noncontrolling Interest	105	—	134	—
Net (Loss) Income Attributable to CONSOL Energy Inc. Shareholders	$(11,368)	$167,329	$238,567	$436,862
Earnings Per Share:				
Basic	$(0.05)	$0.74	$1.05	$1.93
Dilutive	$(0.05)	$0.73	$1.04	$1.91
Weighted Average Number of Common Shares Outstanding:				
Basic	227,654,395	226,744,011	227,491,284	226,582,226
Dilutive	227,654,395	229,163,537	229,191,870	229,002,863
Dividends Paid Per Share	$0.125	$0.100	$0.375	$0.300

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net (Loss) Income	$(11,473)	$167,329	$238,433	$436,862
Other Comprehensive Income (Loss):				
Treasury Rate Lock (Net of tax: $-, $-, $-, $59)	—	—	—	(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, $4,584, $15,016, $13,750)	(8,684)	(7,365)	(24,921)	(22,094)
Amortization of Net Loss (Net of tax: ($10,007), ($11,438), ($29,963), ($34,312))	16,605	18,379	49,725	55,135
Net (Decrease) Increase in the Value of Cash Flow Hedge (Net of tax: $4,161, ($38,790), ($51,716), ($59,912))	(6,459)	59,620	80,280	92,421
Reclassification of Cash Flow Hedges from OCI to Earnings (Net of tax: $29,683, $13,292, $97,760, $36,746)	(47,809)	(20,974)	(153,597)	(56,719)
Other Comprehensive Income (Loss)	(46,347)	49,660	1,763	68,647
Comprehensive Income (Loss)	(57,820)	216,989	240,196	505,509
Add: Comprehensive Loss Attributable to Noncontrolling Interest	105	—	134	—
Comprehensive Income (Loss) Attributable to CONSOL Energy Inc. Shareholders	$(57,715)	$216,989	$240,330	$505,509

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

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

	(Unaudited) September 30, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$230,958	$375,736
Accounts and Notes Receivable:		
Trade	457,057	462,812
Notes Receivables	314,417	314,950
Other Receivables	86,282	105,708
Inventories	266,539	258,335
Deferred Income Taxes	172,212	141,083
Recoverable Income Taxes	12,132	—
Prepaid Expenses	170,927	239,353
Total Current Assets	1,710,524	1,897,977
Property, Plant and Equipment:		
Property, Plant and Equipment	15,143,744	14,087,319
Less—Accumulated Depreciation, Depletion and Amortization	5,215,721	4,760,903
Total Property, Plant and Equipment—Net	9,928,023	9,326,416
Other Assets:		
Deferred Income Taxes	446,530	507,724
Restricted Cash	20,372	22,148
Investment in Affiliates	213,708	182,036
Notes Receivable	1,460	300,492
Other	235,977	288,907
Total Other Assets	918,047	1,301,307
TOTAL ASSETS	$12,556,594	$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) September 30, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts Payable	$497,604	$522,003
Current Portion of Long-Term Debt	22,065	20,691
Accrued Income Taxes	—	75,633
Other Accrued Liabilities	814,033	770,070
Total Current Liabilities	1,333,702	1,388,397
Long-Term Debt:		
Long-Term Debt	3,127,262	3,122,234
Capital Lease Obligations	51,747	55,189
Total Long-Term Debt	3,179,009	3,177,423
Deferred Credits and Other Liabilities:		
Postretirement Benefits Other Than Pensions	2,963,646	3,059,671
Pneumoconiosis Benefits	176,514	173,553
Mine Closing	443,986	406,712
Gas Well Closing	147,067	124,051
Workers' Compensation	150,129	151,034
Salary Retirement	174,844	269,069
Reclamation	52,426	39,969
Other	138,327	124,936
Total Deferred Credits and Other Liabilities	4,246,939	4,348,995
TOTAL LIABILITIES	8,759,650	8,914,815
Stockholders' Equity:		
Common Stock, $.01 Par Value; 500,000,000 Shares Authorized, 227,655,437 Issued and 227,620,682 Outstanding at September 30, 2012; 227,289,426 Issued and 227,056,212 Outstanding at December 31, 2011	2,278	2,273
Capital in Excess of Par Value	2,275,320	2,234,775
Preferred Stock, 15,000,000 shares authorized, None issued and outstanding	—	—
Retained Earnings	2,319,530	2,184,737
Accumulated Other Comprehensive Loss	(799,791)	(801,554)
Common Stock in Treasury, at Cost—34,755 Shares at September 30, 2012 and 233,214 Shares at December 31, 2011	(609)	(9,346)
Total CONSOL Energy Inc. Stockholders' Equity	3,796,728	3,610,885
Noncontrolling Interest	216	—
TOTAL EQUITY	3,796,944	3,610,885
TOTAL LIABILITIES AND EQUITY	$12,556,594	$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 (Unaudited)	$2,273	$2,234,775	$2,184,737	$(801,554)	$(9,346)	$3,610,885	$ —	$3,610,885
Net Income (Loss)	—	—	238,567	—	—	238,567	(134)	238,433
Other Comprehensive Income	—	—	—	1,763	—	1,763	—	1,763
Comprehensive Income (Loss)	—	—	238,567	1,763	—	240,330	(134)	240,196
Issuance of Common Stock	5	1,229	—	—	—	1,234	—	1,234
Issuance of Treasury Stock	—	—	(18,484)	—	8,737	(9,747)	—	(9,747)
Tax Cost From Stock-Based Compensation	—	893	—	—	—	893	—	893
Amortization of Stock-Based Compensation Awards	—	38,423	—	—	—	38,423	—	38,423
Net Change in Greenshale Energy Noncontrolling Interest	—	—	—	—	—	—	350	350
Dividends ($0.375 per share)	—	—	(85,290)	—	—	(85,290)	—	(85,290)
Balance at September 30, 2012	$2,278	$2,275,320	$2,319,530	$(799,791)	$(609)	$3,796,728	$ 216	$3,796,944

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)

	Nine Months Ended September 30,	
	2012	2011
Operating Activities:		
Net Income Attributable to CONSOL Energy Inc. Shareholders	$238,567	$436,862
Adjustments to Reconcile Net Income to Net Cash Provided By Operating Activities:		
Depreciation, Depletion and Amortization	463,048	466,612
Abandonment of Long-Lived Assets	—	115,817
Stock-Based Compensation	38,423	37,083
(Gain) Loss on Sale of Assets	(190,257)	9,993
Loss on Debt Extinguishment	—	16,090
Amortization of Mineral Leases	3,818	4,149
Deferred Income Taxes	(5,225)	120
Equity in Earnings of Affiliates	(22,676)	(19,989)
Changes in Operating Assets:		
Accounts and Notes Receivable	13,359	(50,212)
Inventories	(8,204)	16,264
Prepaid Expenses	(1,362)	(611)
Changes in Other Assets	(8,961)	16,446
Changes in Operating Liabilities:		
Accounts Payable	5,218	98,320
Other Operating Liabilities	(11,130)	66,589
Changes in Other Liabilities	1,469	29,432
Other	14,076	9,439
Net Cash Provided by Operating Activities	530,163	1,252,404
Investing Activities:		
Capital Expenditures	(1,152,021)	(997,463)
Proceeds from Sales of Assets	583,942	695,291
Distributions From, net of (Investments In), Equity Affiliates	(18,701)	70,860
Net Cash Used in Investing Activities	(586,780)	(231,312)
Financing Activities:		
Payments on Short-Term Borrowings	—	(284,000)
Payments on Miscellaneous Borrowings	(6,565)	(9,320)
Payments on Long Term Notes, including Redemption Premium	—	(265,785)
Payments on Securitization Facility	—	(200,000)
Proceeds from Issuance of Long-Term Notes	—	250,000
Tax Benefit from Stock-Based Compensation	2,578	5,034
Dividends Paid	(85,290)	(67,972)
Issuance of Common Stock	1,234	—
Issuance of Treasury Stock	109	6,219
Debt Issuance and Financing Fees	(227)	(15,539)
Net Cash Used In Financing Activities	(88,161)	(581,363)
Net (Decrease) Increase in Cash and Cash Equivalents	(144,778)	439,729
Cash and Cash Equivalents at Beginning of Period	375,736	32,794
Cash and Cash Equivalents at End of Period	$230,958	$472,523

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 nine months ended September 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Anti-Dilutive Options	5,740,444	1,154,051	2,412,502	1,154,051
Anti-Dilutive Restricted Stock Units	1,348,046	—	13,302	—
Anti-Dilutive Performance Share Units	488,179	21,675	—	—
Anti-Dilutive Performance Share Options	501,744	—	501,744	—
	8,078,413	1,175,726	2,927,548	1,154,051

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Options	108,477	72,254	159,611	311,003
Restricted Stock Units	22,025	20,589	548,492	424,958
Performance Share Units	—	—	229,730	40,752
	130,502	92,843	937,833	776,713

The weighted average exercise price per share of the options exercised during the three months ended September 30, 2012 and 2011 was $7.13 and $16.69, respectively. The weighted average exercise price per share of the options exercised during the nine months ended September 30, 2012 and 2011 was $8.39 and $20.00, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net (Loss) Income Attributable to CONSOL Energy Inc. Shareholders	$(11,368)	$167,329	$238,567	$436,862
Weighted average shares of common stock outstanding:				
Basic	227,654,395	226,744,011	227,491,284	226,582,226
Effect of stock-based compensation awards	—	2,419,526	1,700,586	2,420,637
Dilutive	227,654,395	229,163,537	229,191,870	229,002,863
Earnings per share:				
Basic	$(0.05)	$0.74	$1.05	$1.93
Dilutive	$(0.05)	$0.73	$1.04	$1.91

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 September 2012, cash proceeds of $327,964 were received related to the first anniversary note receivable. 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.

Under the joint venture agreements, our joint venture partners have the right for a specified period of time to perform due diligence on the title to the oil and gas interests which we conveyed to them. To the extent our joint venture partners assert claims for title defects, we have a specified period of time in which to review and respond to the asserted title defects, as well as to cure them. We are currently in this review process with Noble and Hess. If Noble or Hess establish any title defects which are not resolved or if the subject acreage is reassigned to CONSOL Energy, then subject to certain deductibles, their aggregate carried cost obligation under the respective joint venture agreements will be reduced by the value the parties previously allocated to the affected acreage in the respective transactions. If a significant percentage of the oil and gas interests we contributed have title defects, the carried costs could be materially reduced and our aggregate share of the drilling and completion costs for wells in these joint ventures could materially increase. For additional information on the Noble and Hess carries, see Note 8 - Property, Plant and Equipment in the Notes to the Unaudited Consolidated Financial Statements.

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 September 30, 2011	Nine Months Ended September 30, 2011
Total Revenue and Other Income	$1,502,660	$4,531,696
Earnings Before Income Taxes	$195,882	$538,152
Net Income	$163,822	$427,491
Basic Earnings Per Share	$0.72	$1.89
Dilutive Earnings Per Share	$0.71	$1.87

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 statements of cash flows in the nine 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 proceeds of $193,000 before transaction fees of $2,619. 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 nine months ended September 30 are as follows:

	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended		Nine Months Ended		Three Months Ended		Nine Months Ended	
	September 30,		September 30,		September 30,		September 30,	
	2012	2011	2012	2011	2012	2011	2012	2011
Service cost	$5,527	$4,364	$15,530	$13,093	$4,525	$3,419	$14,291	$10,258
Interest cost	9,396	9,436	28,190	28,308	33,687	44,935	102,008	134,804
Expected return on plan assets	(11,538)	(9,631)	(34,617)	(28,892)	—	—	—	—
Amortization of prior service cost (credits)	(408)	(167)	(1,223)	(500)	(13,409)	(11,599)	(38,418)	(34,798)
Recognized net actuarial loss	11,959	9,526	35,876	28,577	20,255	26,341	60,620	79,023
Net periodic benefit cost	$14,936	$13,528	$43,756	$40,586	$45,058	$63,096	$138,501	$189,287

For the nine months ended September 30, 2012, $104,877 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 $80,571 reduction in the OPEB liability with a corresponding adjustment of $50,276 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 $6,283 reduction in OPEB expense compared to what was originally expected to be recognized for the nine months ended September 30, 2012. Additionally, the change will result in a $3,142 reduction to OPEB expense compared to what was originally expected to be recognized for the remaining three 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 nine months ended September 30, 2012, $127,947 of other postemployment benefits have been paid.
For the nine months ended September 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 nine months ended September 30 are as follows:

	CWP				Workers' Compensation			
	Three Months Ended		Nine Months Ended		Three Months Ended		Nine Months Ended	
	September 30,		September 30,		September 30,		September 30,	
	2012	2011	2012	2011	2012	2011	2012	2011
Service cost	$1,177	$1,155	$3,533	$3,465	$3,634	$4,468	$10,903	$13,404
Interest cost	1,991	2,332	5,973	6,997	1,778	2,059	5,335	6,178
Amortization of actuarial gain	(4,933)	(5,477)	(14,799)	(16,432)	(986)	(977)	(2,958)	(2,930)
State administrative fees and insurance bond premiums	—	—	—	—	1,795	1,459	5,340	4,667
Legal and administrative costs	750	750	2,250	2,250	648	719	1,943	2,156
Net periodic (benefit) cost	$(1,015)	$(1,240)	$(3,043)	$(3,720)	$6,869	$7,728	$20,563	$23,475

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 nine months ended September 30, 2012, $8,606 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 nine months ended September 30, 2012, $23,246 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 Nine Months Ended September 30,			
	2012		2011	
	Amount	Percent	Amount	Percent
Statutory U.S. federal income tax rate	$104,601	35.0%	$192,599	35.0%
Excess tax depletion	(53,932)	(18.1)	(76,561)	(13.9)
Effect of domestic production activities	(121)	(0.1)	(10,038)	(1.8)
Effect of federal tax accrual to tax return	6,004	2.0	(10,249)	(1.9)
IRS and state tax examination settlements	(2,769)	(0.9)	(5,187)	(0.9)
Net effect of state income taxes	5,489	1.8	16,088	2.9
Other	1,156	0.5	6,769	1.2
Income Tax Expense / Effective Rate	$60,428	20.2%	$113,421	20.6%

The effective rates for the nine months ended September 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 nine months ended September 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 $48,976 in federal and state income taxes related to the sale.

During the nine months ended September 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 is reflected in the IRS and state tax examination settlements line of the rate reconciliation.

CONSOL Energy was advised in a prior period by the Canadian Revenue Agency and various provinces that its appeal of tax deficiencies paid as a result of the Agency's audit of the Canadian tax returns filed for years 1997 through 2003 had been successfully resolved. As a result of the audit settlement, the Company amended previously filed U.S. income tax returns for tax years 1997 through 2001 which will result in a foreign income tax reduction of $1,786 reported as a discrete federal income tax item. This discrete transaction was reflected in the IRS and state tax examination settlements line of the rate reconciliation.
For the three months ended September 30, 2012, CONSOL Energy recognized additional tax expense as a result of changes in estimates of percentage depletion and Domestic Production Activities Deduction related to the prior-year tax provision. The result of these changes was a tax increase of $6,004.
The total amounts of uncertain tax positions at September 30, 2012 and 2011 were $25,570 and $42,932, 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 nine months ended September 30, 2012 and 2011.
CONSOL Energy recognizes interest accrued related to uncertain tax positions in its interest expense. As of September 30, 2012 and 2011, the Company reported an accrued interest liability relating to uncertain tax positions of $7,095 and $7,309, respectively. The accrued interest liability includes $1,722 of interest expense and $1,160 of interest income that is reflected in the Company’s Consolidated Statements of Income for the nine months ended September 30, 2012 and 2011, respectively.
CONSOL Energy recognizes penalties accrued related to unrecognized tax benefits in its income tax expense. As of September 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.

The Internal Revenue Service issued its audit report relating to the examination of CONSOL Energy's 2006 and 2007 U.S. income tax returns during the nine months ended September 30, 2011. As a result of these findings, CONSOL Energy paid federal and state income tax deficiencies of $10,765 and $1,523, respectively. The federal and state income tax deficiencies paid were related to the IRS' examination of the Company's 2006 and 2007 tax returns and were the result of changes in the timing of certain tax deductions. The change in timing of certain tax deductions increased the tax benefit of percentage depletion by $2,594 and $908 in tax years 2006 and 2007, respectively. The Company also realized a tax benefit of $981 on state income taxes related to the federal percentage depletion increases.

NOTE 6—INVENTORIES:

Inventory components consist of the following:

	September 30, 2012	December 31, 2011
Coal	$100,843	$105,378
Merchandise for resale	37,009	43,639
Supplies	128,687	109,318
Total Inventories	$266,539	$258,335

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 $19,627 and $22,406 at September 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 September 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 $420 and $1,276 for three and nine months ended September 30, 2012, respectively. Costs associated with the receivables facility totaled $386 and $1,683 for three and nine months ended September 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 September 30, 2012 and December 31, 2011, eligible accounts receivable totaled $200,000 and $192,700, respectively. There was subordinated retained interest of $39,221 at September 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 September 30, 2012 and December 31, 2011. However, there were letters of credit of $160,779 outstanding against the facility at September 30, 2012. The accounts receivable securitization program decreased by $200,000 in the nine months ended September 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:

	September 30, 2012	December 31, 2011
Coal and other plant and equipment	$5,760,993	$5,160,759
Proven gas properties	1,546,117	1,542,837
Intangible drilling cost	1,527,104	1,277,678
Coal properties and surface lands	1,340,278	1,340,757
Unproven gas properties	1,292,532	1,258,027
Gas gathering equipment	1,000,740	963,494
Airshafts	686,795	659,736
Leased coal lands	540,932	540,817
Mine development	515,575	457,179
Gas wells and related equipment	442,969	408,814
Coal advance mining royalties	400,304	393,340
Other gas assets	82,176	79,816
Gas advance royalties	7,229	4,065
Total Property Plant and Equipment	15,143,744	14,087,319
Less: Accumulated DD&A	5,215,721	4,760,903

Total Net PP&E	$9,928,023	$9,326,416

Industry Participation Agreements

As of September 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 September 30, 2012:

Shale Play	Industry Participation Agreement Partner	Industry Participation Agreement Date	Total Drilling Carries	Drilling Carries Billed to/from Partner	Drilling Carries Remaining (A)
Marcellus	Noble Energy, Inc.	September 30, 2011	$ 2,100,000	$ 10,210	$ 2,089,790
Utica	Hess Ohio Developments, LLC	October 21, 2011	$ 534,000	$ 11,536	$ 522,464

(A) See Note 2 - Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for discussion of possible reductions to remaining drilling carry amounts.

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 5.20 to 1.00 at September 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 2.43 to 1.00 at September 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 0.08 to 1.00 at September 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 September 30, 2012, the $1,500,000 facility had no borrowings outstanding and $100,292 of letters of credit outstanding, leaving $1,399,708 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 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 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 0.00 to 1.00 at September 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 42.40 to 1.00 at September 30, 2012. At September 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 nine months ended September 30, 2012 was 1.96% and 1.98%, respectively. Accrued interest of $58 is included in Other Accrued Liabilities in the Consolidated Balance Sheet at September 30, 2012.

There was no accrued interest at December 31, 2011.

NOTE 10—LONG-TERM DEBT:

	September 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 September 30, 2012 and December 31, 2011)	31,053	31,053
Other long-term notes maturing at various dates through 2031 (total value of $7,988 less unamortized discount of $1,676 at September 30, 2012)	6,312	75
	3,140,230	3,133,993
Less amounts due in one year	12,968	11,759
Long-Term Debt	$3,127,262	$3,122,234

Accrued interest related to Long-Term Debt of $113,583 and $63,259 was included in Other Accrued Liabilities in the Consolidated Balance Sheets at September 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 $1,098,399.

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 (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%. In 2011, CONSOL Energy established an initial accrual based on its allocated share of the costs among the viable former customers of American Electric Corp. In the nine months ended September 30, 2012, CONSOL Energy funded $250 to an independent trust established for the remediation. 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 nine months ended September 30, 2012 and 2011, respectively. CONSOL Energy funded $400 in the nine months ended September 30, 2012 to an independent trust established for this remediation. Contributions of $250 were made to the trust in the nine months ended September 30, 2011. As of September 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 $4,476. Accordingly, the liability reflected in Other Accrued Liabilities was reduced by these settled claims. The remaining net liability at September 30, 2012 is $3,084.

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.

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. An amended complaint was filed, which added two additional claims alleging that gas hedging receipts should have been used as the basis for royalty payments and that severance tax should not be allowed as a post-production deduction from royalties. A motion to dismiss those claims was filed and was denied. 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. An amended complaint was filed, which added an additional claim that gas hedging receipts should have been used as the basis for royalty payments. A motion to dismiss those claims was filed and was denied. 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 and reply briefs have been filed and oral argument took place on October 11, 2012. A decision will likely be rendered within sixty days following that 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 is scheduled for trial on March 11, 2013. Mediation is presently scheduled in early December 2012. 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 ruled for CNX Gas Company and CONSOL Energy, holding that the “roof/rider” coal is included in the Pittsburgh 8 coal seam. The plaintiffs have indicated that they intend to appeal that 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. Mediation is scheduled for late November, 2012. 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 September 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	$193,405	$90,837	$102,568	$—	$—
Environmental	56,294	54,566	1,728	—	—
Other	81,648	34,640	47,008	—	—
Total Letters of Credit	331,347	180,043	151,304	—	—
Surety Bonds:					
Employee-Related	204,884	204,884	—	—	—
Environmental	495,035	452,882	42,153	—	—
Other	29,140	28,884	255	—	1
Total Surety Bonds	729,059	686,650	42,408	—	1
Guarantees:					
Coal	60,901	10,346	45,555	1,000	4,000
Gas	113,512	62,905	19,985	—	30,622
Other	432,686	84,702	132,949	79,370	135,665
Total Guarantees	607,099	157,953	198,489	80,370	170,287
Total Commitments	$1,667,505	$1,024,646	$392,201	$80,370	$170,288

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 September 30, 2012, the purchase obligations for each of the next five years and beyond were as follows:

Obligations Due	Amount
Less than 1 year	$480,946
1 - 3 years	393,844
3 - 5 years	519,678
More than 5 years	1,494,158
Total Purchase Obligations	$2,888,626

Costs related to these purchase obligations include:

	Three Months Ended September, 30		Nine Months Ended September 30,	
	2012	2011	2012	2011
Major equipment purchases	$59,799	$12,889	$104,980	$30,066
Firm transportation expense	18,844	15,225	49,711	43,359
Gas drilling obligations	27,100	24,423	85,192	74,587
Other	65	65	492	256

Total costs related to purchase obligations	$105,808	$52,602	$240,375	$148,268

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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 September 30, 2012, the total notional amount of the Company’s outstanding natural gas swap contracts was 169 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, $49,944 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 September 30, 2012 of CONSOL Energy's derivative instruments, which were all natural gas swaps and qualify as cash flow hedges, was an asset of $148,089 and a liability of $14,395. The total asset is comprised of $85,366 and $62,723 which were included in Prepaid Expense and Other Assets, respectively, on the Consolidated Balance Sheets. The total liability is comprised of $2,923 and $11,472 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 September 30,	
	2012	2011
Natural Gas Price Swaps		
Gain/(Loss) recognized in Accumulated OCI	$(6,459)	$59,620
Gain reclassified from Accumulated OCI into Outside Sales	$47,809	$20,974
Gain recognized in Outside Sales for ineffectiveness	$1,732	$333

	Nine Months Ended September 30,	
	2012	2011
Natural Gas Price Swaps		
Gain recognized in Accumulated OCI	$80,280	$92,421
Gain reclassified from Accumulated OCI into Outside Sales	$153,597	$56,719
Gain recognized in Outside Sales for ineffectiveness	$1,778	$297

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 September 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	$—	$133,694	$—	$—	$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:

	September 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$230,958	$230,958	$375,736	$375,736
Restricted cash	$20,372	$20,372	$22,148	$22,148
Long-term debt	$(3,140,230)	$(3,342,072)	$(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 nine months ended September 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 nine months ended September 30, 2012, the Low Volatile Metallurgical aggregated segment includes the Buchanan Mine and Amonate Complex. For the nine months ended September 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 September 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	Al Ot
Sales—outside	$667,372	$110,239	$48,484	$5,214	$831,309	$94,169	$36,253	$32,288	$2,392	$165,102	$8
Sales—purchased gas	—	—	—	—	—	—	—	—	953	953	—
Sales—gas royalty interests	—	—	—	—	—	—	—	—	12,968	12,968	—
Freight—outside	—	—	—	27,430	27,430	—	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	345	345	37
Total Sales and Freight	$667,372	$110,239	$48,484	$32,644	$858,739	$94,169	$36,253	$32,288	$16,658	$179,368	$1
Earnings (Loss) Before Income Taxes	$89,742	$42,722	$9,640	$(138,080)	$4,024	$30,983	$6,347	$(3,441)	$(22,225)	$11,664	$1
Segment assets					$5,594,926					$5,870,451	$3
Depreciation, depletion and amortization					$95,702					$52,215	$-
Capital expenditures					$254,864					$166,617	$1

(A) Included in the Coal segment are sales of $129,014 to First Energy which comprises over 10% of sales.

(B) Includes equity in earnings of unconsolidated affiliates of $1,298, $2,503 and $3,772 for Coal, Gas and All Other, respectively.

(C) Includes investments in unconsolidated equity affiliates of $19,750, $135,048 and $58,910 for Coal, Gas and All Other, respectively.

Industry segment results for the three months ended September 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	Al Ot
Sales—outside	$732,135	$307,969	$83,065	$12,593	$1,135,762	$116,954	$39,035	$38,974	$3,411	$198,374	$8
Sales—purchased gas	—	—	—	—	—	—	—	—	1,155	1,155	—
Sales—gas royalty interests	—	—	—	—	—	—	—	—	17,083	17,083	—
Freight—outside	—	—	—	59,871	59,871	—	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	726	726	49
Total Sales and Freight	$732,135	$307,969	$83,065	$72,464	$1,195,633	$116,954	$39,035	$38,974	$22,375	$217,338	$1
Earnings (Loss) Before Income Taxes	$101,579	$203,813	$25,799	$(62,914)	$268,277	$46,819	$12,450	$(6,360)	$(52,340)	$569	$9
Segment assets					$5,131,432					$5,959,480	$3
Depreciation, depletion and amortization					$96,797					$58,131	$4
Capital expenditures					$182,588					$215,830	$1

(D) Included in the Coal segment are sales of $159,842 to Xcoal Energy & Resources comprising over 10% of sales.

(E) Includes equity in earnings of unconsolidated affiliates of $4,842, $693 and $3,142 for Coal, Gas and All Other, respectively.

(F) Includes investments in unconsolidated equity affiliates of $33,037, $91,853 and $50,928 for Coal, Gas and All Other, respectively.

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Industry segment results for the nine months ended September 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	$2,227,728	$403,460	$180,302	$18,905	$2,830,395	$281,784	$83,774	$100,868	$6,978	$473,404
Sales—purchased gas	—	—	—	—	—	—	—	—	2,443	2,443
Sales—gas royalty interests	—	—	—	—	—	—	—	—	34,707	34,707
Freight—outside	—	—	—	126,195	126,195	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	1,171	1,171
Total Sales and Freight	$2,227,728	$403,460	$180,302	$145,100	$2,956,590	$281,784	$83,774	$100,868	$45,299	$511,725
Earnings (Loss) Before Income Taxes	$351,883	$164,842	$44,994	$(142,847)	$418,872	$91,717	$14,433	$(9,571)	$(71,271)	$25,308
Segment assets					$5,594,926					$5,870,4
Depreciation, depletion and amortization					$297,148					$148,344
Capital expenditures					$702,880					$408,278

(G) Included in the Coal segment are sales of $409,745 to First Energy and $382,950 to Xcoal Energy & Resources each comprising over 10% of sales.

(H) Includes equity in earnings of unconsolidated affiliates of $7,588, $6,484 and $8,604 for Coal, Gas and All Other, respectively.

(I) Includes investments in unconsolidated equity affiliates of $19,750, $135,048 and $58,910 for Coal, Gas and All Other, respectively.

Industry segment results for the nine months ended September 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 Ga
Sales—outside	$2,315,467	$824,035	$278,986	$59,465	$3,477,953	$346,713	$88,315	$119,899	$8,697	$563,62
Sales—purchased gas	—	—	—	—	—	—	—	—	3,297	3,297
Sales—gas royalty interests	—	—	—	—	—	—	—	—	52,191	52,191
Freight—outside	—	—	—	156,311	156,311	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	2,648	2,648
Total Sales and Freight	$2,315,467	$824,035	$278,986	$215,776	$3,634,264	$346,713	$88,315	$119,899	$66,833	$621,76
Earnings (Loss) Before Income Taxes	$421,806	$533,600	$115,561	$(351,848)	$719,119	$140,482	$28,421	$(8,486)	$(107,426)	$52,991
Segment assets					$5,131,432					$5,959,4
Depreciation, depletion and amortization					$293,793					$159,10
Capital expenditures					$435,818					$535,06

(J) Included in the Coal segment are sales of $539,568 to Xcoal Energy & Resources comprising over 10% of sales

(K) Includes equity in earnings of unconsolidated affiliates of $13,544, $1,694 and $4,751 for Coal, Gas and All Other, respectively.

(L) Includes investments in unconsolidated equity affiliates of $33,037, $91,853 and $50,928 for Coal, Gas and All Other, respectively.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Segment Earnings Before Income Taxes for total reportable business segments	$15,688	$268,846	$444,180	$772,110
Segment Earnings Before Income Taxes for all other businesses	12,274	9,561	36,122	12,134
Interest income (expense), net and other non-operating activity (M)	(56,338)	(61,167)	(175,323)	(197,792)
Transaction and Financing Fees (M)	—	(14,907)	—	(14,907)
Other Corporate Items (M)	(2,995)	(1,911)	(6,118)	(5,172)
Loss on debt extinguishment	—	—	—	(16,090)
(Loss) Earnings Before Income Taxes	$(31,371)	$200,422	$298,861	$550,283

Total Assets:	September, 30	
	2012	2011
Segment assets for total reportable business segments	$11,465,377	$11,090,912
Segment assets for all other businesses	376,400	329,207
Items excluded from segment assets:		
Cash and other investments (M)	40,331	64,436
Recoverable income taxes	12,132	11,504
Deferred tax assets	618,742	616,105
Bond issuance costs	43,612	50,884
Total Consolidated Assets	$12,556,594	$12,163,048

(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 senior notes due April 1, 2017, the $1,250,000, 8.250% per annum senior notes due April 1, 2020, and the $250,000, 6.375% per annum senior 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 September 30, 2012 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$165,446	$861,011	$58,405	$(821)	$1,084,041
Sales—Gas Royalty Interests	—	12,968	—	—	—	12,968
Sales—Purchased Gas	—	953	—	—	—	953
Freight—Outside	—	—	27,430	—	—	27,430
Other Income	40,372	11,774	18,006	4,917	(40,372)	34,697
Total Revenue and Other Income	40,372	191,141	906,447	63,322	(41,193)	1,160,089
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	18,699	96,619	647,158	57,408	7,646	827,530
Gas Royalty Interests Costs	—	10,565	—	—	(22)	10,543
Purchased Gas Costs	—	737	—	—	—	737
Related Party Activity	10,411	—	(18,962)	427	8,124	—
Freight Expense	—	—	27,430	—	—	27,430
Selling, General and Administrative Expenses	—	9,906	26,412	363	—	36,681
Depreciation, Depletion and Amortization	3,085	52,214	98,060	518	—	153,877
Interest Expense	50,811	1,145	2,267	11	(159)	54,075
Taxes Other Than Income	217	8,426	71,264	680	—	80,587
Total Costs	83,223	179,612	853,629	59,407	15,589	1,191,460
(Loss) Earnings Before Income Taxes	(42,851)	11,529	52,818	3,915	(56,782)	(31,371)
Income Taxes (Benefit) Expense	(31,483)	4,433	5,661	1,491	—	(19,898)
Net (Loss) Income	(11,368)	7,096	47,157	2,424	(56,782)	(11,473)
	—	105	—	—	—	105

Add: Net Loss Attributable to Noncontrolling Interest						
Net (Loss) Income Attributable to CONSOL Energy Inc. Shareholders	$(11,368)	$7,201	$47,157	$2,424	$(56,782)	$(11,368)

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Balance Sheet at September 30, 2012 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Assets:						
Current Assets:						
Cash and Cash Equivalents	$38,976	$191,354	$107	$521	$—	$230,958
Accounts and Notes Receivable:						
Trade	—	52,899	—	404,158	—	457,057
Notes Receivables	113	311,754	2,550	—	—	314,417
Other Receivables	4,856	106,607	6,146	4,373	(35,700)	86,282
Inventories	—	14,355	215,175	37,009	—	266,539
Recoverable Income Taxes	17,147	(5,015)	—	—	—	12,132
Deferred Income Taxes	195,042	(22,830)	—	—	—	172,212
Prepaid Expenses	34,287	90,514	44,911	1,215	—	170,927
Total Current Assets	290,421	739,638	268,889	447,276	(35,700)	1,710,524
Property, Plant and Equipment:						
Property, Plant and Equipment	214,229	5,852,231	9,052,502	24,782	—	15,143,744
Less-Accumulated Depreciation, Depletion and Amortization	121,503	921,974	4,154,478	17,766	—	5,215,721
Total Property, Plant and Equipment-Net	92,726	4,930,257	4,898,024	7,016	—	9,928,023
Other Assets:						
Deferred Income Taxes	893,348	(446,818)	—	—	—	446,530
Restricted Cash	20,372	—	—	—	—	20,372
Investment in Affiliates	9,528,688	135,048	779,574	—	(10,229,602)	213,708
Notes Receivable	266	—	1,194	—	—	1,460
Other	124,536	73,386	27,738	10,317	—	235,977
Total Other Assets	10,567,210	(238,384)	808,506	10,317	(10,229,602)	918,047
Total Assets	$10,950,357	$5,431,511	$5,975,419	$464,609	$(10,265,302)	$12,556,594
Liabilities and Stockholders' Equity:						
Current Liabilities:						
Accounts Payable	$202,002	$194,280	$89,539	$11,783	$—	$497,604
Accounts Payable (Recoverable)—Related Parties	2,989,694	9,656	(3,251,780)	288,130	(35,700)	—
Current Portion Long-Term Debt	1,883	6,032	13,413	737	—	22,065
Other Accrued Liabilities	678,007	56,202	67,892	11,932	—	814,033
Total Current Liabilities	3,871,586	266,170	(3,080,936)	312,582	(35,700)	1,333,702
Long-Term Debt:	3,005,860	47,399	124,347	1,403	—	3,179,009
Deferred Credits and Other Liabilities						
Postretirement Benefits Other Than Pensions	—	—	2,963,646	—	—	2,963,646
Pneumoconiosis Benefits	—	—	176,514	—	—	176,514
Mine Closing	—	—	443,986	—	—	443,986
Gas Well Closing	—	78,808	68,259	—	—	147,067
Workers' Compensation	—	—	149,846	283	—	150,129

Salary Retirement	174,844	—	—	—	—	174,844
Reclamation	—	—	52,426	—	—	52,426
Other	101,339	32,254	4,734	—	—	138,327
Total Deferred Credits and Other Liabilities	276,183	111,062	3,859,411	283	—	4,246,939
Total CONSOL Energy Inc. Stockholders' Equity	3,796,728	5,006,664	5,072,597	150,341	(10,229,602)	3,796,728
Noncontrolling Interest	—	216	—	—	—	216
Total Liabilities and Equity	$10,950,357	$5,431,511	$5,975,419	$464,609	$(10,265,302)	$12,556,594

Income Statement for the Three Months Ended September 30, 2011 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$199,100	$1,163,339	$60,873	$(1,623)	$1,421,689
Sales—Gas Royalty Interests	—	17,083	—	—	—	17,083
Sales—Purchased Gas	—	1,155	—	—	—	1,155
Freight—Outside	—	—	59,871	—	—	59,871
Other Income	232,472	(13,788)	33,414	1,412	(231,579)	21,931
Total Revenue and Other Income	232,472	203,550	1,256,624	62,285	(233,202)	1,521,729
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	23,375	106,331	667,100	58,401	24,061	879,268
Gas Royalty Interests Costs	—	15,420	—	—	(11)	15,409
Purchased Gas Costs	—	398	—	—	—	398
Related Party Activity	2,653	—	(8,346)	478	5,215	—
Freight Expense	—	—	59,871	—	—	59,871
Selling, General and Administrative Expenses	—	13,311	58,582	472	(25,673)	46,692
Depreciation, Depletion and Amortization	3,301	58,131	97,745	573	—	159,750
Interest Expense	58,421	2,332	(1,784)	13	(98)	58,884
Taxes Other Than Income	1,805	7,154	76,137	694	—	85,790
Abandonment of Long-Lived Assets	—	—	338	—	—	338
Transaction and Financing Fees	14,907	—	—	—	—	14,907
Total Costs	104,462	203,077	949,643	60,631	3,494	1,321,307
Earnings (Loss) Before Income Taxes	128,010	473	306,981	1,654	(236,696)	200,422
Income Tax Expense (Benefit)	(39,319)	(2,440)	74,226	626	—	33,093
Net Income (Loss)	$167,329	$2,913	$232,755	$1,028	$(236,696)	$167,329

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 Receivables	2,669	311,754	527	—	—	314,950
Other Receivables	2,913	91,582	7,458	3,755	—	105,708
Inventories	—	8,600	206,096	43,639	—	258,335
Recoverable Income Taxes	—	—	—	—	—	—
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
Total 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 CONSOL Energy Inc. Stockholders' Equity	3,610,885	5,262,928	4,409,954	128,997	(9,801,879)	3,610,885
Total Liabilities and Equity	$10,583,868	$5,678,412	$5,599,139	$466,160	$(9,801,879)	$12,525,700

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Income Statement for the Nine Months Ended September 30, 2012 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$474,574	$2,919,814	$192,212	$(1,795)	$3,584,805
Sales—Gas Royalty Interests	—	34,707	—	—	—	34,707
Sales—Purchased Gas	—	2,443	—	—	—	2,443
Freight—Outside	—	—	126,195	—	—	126,195
Other Income	399,817	46,177	230,930	16,089	(399,817)	293,196
Total Revenue and Other Income	399,817	557,901	3,276,939	208,301	(401,612)	4,041,346
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	90,230	296,959	1,992,371	186,635	22,265	2,588,460
Gas Royalty Interests Costs	—	27,951	—	—	(35)	27,916
Purchased Gas Costs	—	2,123	—	—	—	2,123
Related Party Activity	1,575	—	5,078	1,376	(8,029)	—
Freight Expense	—	—	126,195	—	—	126,195
Selling, General and Administrative Expenses	—	29,199	79,169	1,044	—	109,412
Depreciation, Depletion and Amortization	8,901	148,343	304,245	1,559	—	463,048
Interest Expense	158,505	3,554	7,056	33	(360)	168,788
Taxes Other Than Income	159	24,790	229,381	2,213	—	256,543
Total Costs	259,370	532,919	2,743,495	192,860	13,841	3,742,485
Earnings (Loss) Before Income Taxes	140,447	24,982	533,444	15,441	(415,453)	298,861
Income Tax Expense (Benefit)	(98,120)	9,706	143,001	5,841	—	60,428
Net Income (Loss)	238,567	15,276	390,443	9,600	(415,453)	238,433
Add: Net Loss Attributable to Noncontrolling Interest	—	134	—	—	—	134
Net Income (Loss) Attributable to CONSOL Energy Inc. Shareholders	$238,567	$15,410	$390,443	$9,600	$(415,453)	$238,567

Income Statement for the Nine Months Ended September 30, 2011 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$566,272	$3,559,954	$171,027	$(4,086)	$4,293,167
Sales—Gas Royalty Interests	—	52,191	—	—	—	52,191
Sales—Purchased Gas	—	3,297	—	—	—	3,297
Freight—Outside	—	—	156,311	—	—	156,311
Other Income	629,116	(9,473)	55,051	20,008	(624,634)	70,068
Total Revenue and Other Income	629,116	612,287	3,771,316	191,035	(628,720)	4,575,034
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion, and amortization shown below)	86,775	284,908	2,012,261	166,106	70,326	2,620,376
Gas Royalty Interests Costs	—	46,620	—	—	(38)	46,582
Purchased Gas Costs	—	2,850	—	—	—	2,850
Related Party Activity	117	—	(21,083)	1,479	19,487	—
Freight Expense	—	—	156,122	—	—	156,122
Selling, General and Administrative Expenses	—	35,303	168,312	1,072	(74,376)	130,311
Depreciation, Depletion and Amortization	8,665	159,109	297,017	1,821	—	466,612
Interest Expense	178,849	7,564	3,799	40	(289)	189,963
Taxes Other Than Income	5,191	23,230	234,411	2,289	—	265,121
Abandonment of Long-Lived Assets	—	—	115,817	—	—	115,817
Loss on Debt Extinguishment	16,090	—	—	—	—	16,090
Transaction and Financing Fees	14,907	—	—	—	—	14,907
Total Costs	310,594	559,584	2,966,656	172,807	15,110	4,024,751
Earnings (Loss) Before Income Taxes	318,522	52,703	804,660	18,228	(643,830)	550,283
Income Tax Expense (Benefit)	(118,340)	18,029	206,837	6,895	—	113,421
Net Income (Loss)	$436,862	$34,674	$597,823	$11,333	$(643,830)	$436,862

Cash Flow for the Nine Months Ended September 30, 2012 (unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Cash Provided by (Used In) Operating Activities	$(245,017)	$139,026	$635,257	$897	$—	$530,163
Cash Flows from Investing Activities:						
Capital Expenditures	$(40,863)	$(408,278)	$(702,880)	$—	$—	$(1,152,021)
Proceeds from Sales of Assets	169,500	359,636	54,756	50	—	583,942
Distributions from, net of (Investments In), Equity Affiliates	—	(31,650)	12,949	—	—	(18,701)
Net Cash (Used in) Provided by Investing Activities	$128,637	$(80,292)	$(635,175)	$50	$—	$(586,780)
Cash Flows from Financing Activities:						
Dividends (Paid) Received	$114,710	$(200,000)	$—	$—	$—	$(85,290)
Other Financing Activities	3,304	(4,107)	(1,729)	(339)	—	(2,871)
Net Cash (Used in) Provided by Financing Activities	$118,014	$(204,107)	$(1,729)	$(339)	$—	$(88,161)

Cash Flow for the Nine Months Ended September 30, 2011 (unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Cash Provided by (Used In) Operating Activities	$515,622	$313,221	$425,702	$(2,141)	$—	$1,252,404
Cash Flows from Investing Activities:						
Capital Expenditures	$(26,578)	$(535,068)	$(435,817)	$—	$—	$(997,463)
Proceeds from Sales of Assets	10	688,505	5,304	1,472	—	695,291
Distributions from, net of (Investments In), Equity Affiliates	—	66,590	4,270	—	—	70,860
Net Cash (Used in) Provided by Investing Activities	$(26,568)	$220,027	$(426,243)	$1,472	$—	$(231,312)
Cash Flows from Financing Activities:						
Dividends Paid	$(67,972)	$—	$—	$—	$—	$(67,972)
Payments on Short-Term Borrowings	(155,000)	(129,000)	—	—	—	(284,000)
Payments on Securitization Facility	(200,000)	—	—	—	—	(200,000)
Proceeds from Issuance of Long-Term Notes	250,000	—	—	—	—	250,000
Payments on Long-Term Notes, including redemption premium	(265,785)	—	—	—	—	(265,785)
Debt Issuance and Financing Fees	(10,499)	(5,040)	—	—	—	(15,539)
Other Financing Activities	10,559	(7,044)	(994)	(588)	—	1,933
Net Cash (Used in) Provided by Financing Activities	$(438,697)	$(141,084)	$(994)	$(588)	$—	$(581,363)

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

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net (Loss) Income	$(11,368)	$7,096	$47,157	$2,424	$(56,782)	$(11,473)
Other Comprehensive Income (Loss):						
Actuarially Determined Long-Term Liability Adjustments						
Amortization of Prior Service Cost	(8,684)	—	(8,684)	—	8,684	(8,684)
Amortization of Net Loss	16,605	—	16,605	—	(16,605)	16,605
Net (Decrease) Increase in the Value of Cash Flow Hedge	(6,459)	(6,459)	—	—	6,459	(6,459)
Reclassification of Cash Flow Hedges from OCI to Earnings	(47,809)	(47,809)	—	—	47,809	(47,809)
Other Comprehensive (Loss) Income:	(46,347)	(54,268)	7,921	—	46,347	(46,347)
Comprehensive (Loss) Income	(57,715)	(47,172)	55,078	2,424	(10,435)	(57,820)
Add: Comprehensive Loss Attributable to Noncontrolling Interest	—	105	—	—	—	105
Comprehensive (Loss) Income Attributable to CONSOL Energy Inc. Shareholders	$(57,715)	$(47,067)	$55,078	$2,424	$(10,435)	$(57,715)

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

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income (Loss)	$167,329	$2,913	$232,755	$1,028	$(236,696)	$167,329
Other Comprehensive Income (Loss):						
Treasury Rate Lock	—	—	—	—	—	—
Actuarially Determined Long-Term Liability Adjustments						
Amortization of Prior Service Cost	(7,365)	—	(7,365)	—	7,365	(7,365)
Amortization of Net Loss	18,379	—	18,379	—	(18,379)	18,379
Net Increase (Decrease) in the Value of Cash Flow Hedge	59,620	59,620	—	—	(59,620)	59,620
Reclassification of Cash Flow Hedges from OCI to Earnings	(20,974)	(20,974)	—	—	20,974	(20,974)
Other Comprehensive Income (Loss):	49,660	38,646	11,014	—	(49,660)	49,660
Comprehensive Income (Loss)	$216,989	$41,559	$243,769	$1,028	$(286,356)	$216,989

Statement of Comprehensive Income for the Nine Months Ended September 30, 2012 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income (Loss)	$238,567	$15,276	$390,443	$9,600	$(415,453)	$238,433
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	(24,921)	—	(24,921)	—	24,921	(24,921)
Amortization of Net Loss	49,725	—	49,725	—	(49,725)	49,725
Net Increase (Decrease) in the Value of Cash Flow Hedge	80,280	80,280	—	—	(80,280)	80,280
Reclassification of Cash Flow Hedges from OCI to Earnings	(153,597)	(153,597)	—	—	153,597	(153,597)
Other Comprehensive Income (Loss):	1,763	(73,317)	75,080	—	(1,763)	1,763
Comprehensive Income (Loss)	240,330	(58,041)	465,523	9,600	(417,216)	240,196
Add: Comprehensive Loss Attributable to Noncontrolling Interest	—	134	—	—	—	134
Comprehensive Income (Loss) Attributable to CONSOL Energy Inc. Shareholders'	$240,330	$(57,907)	$465,523	$9,600	$(417,216)	$240,330

Statement of Comprehensive Income for the Nine Months Ended September 30, 2011 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income (Loss)	$436,862	$34,674	$597,823	$11,333	$(643,830)	$436,862
Other Comprehensive Income (Loss):						
Treasury Rate Lock	(96)	—	—	—	—	(96)
Actuarially Determined Long-Term Liability Adjustments						
Amortization of Prior Service Cost	(22,094)	—	(22,094)	—	22,094	(22,094)
Amortization of Net Loss	55,135	—	55,135	—	(55,135)	55,135
Net Increase (Decrease) in the Value of Cash Flow Hedge	92,421	92,421	—	—	(92,421)	92,421
Reclassification of Cash Flow Hedges from OCI to Earnings	(56,719)	(56,719)	—	—	56,719	(56,719)
Other Comprehensive Income (Loss):	68,647	35,702	33,041	—	(68,743)	68,647
Comprehensive Income (Loss)	$505,509	$70,376	$630,864	$11,333	$(712,573)	$505,509

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NOTE 16—RELATED PARTY TRANSACTIONS:

CONE Gathering LLC Related Party Transactions

During the nine months ended September 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 $5,895 and $13,619, for the three and nine months ended September 30, 2012, respectively, which were included in Cost of Goods Sold on the Consolidated Statements of Income.

As of September 30, 2012 and December 31, 2011, CONSOL Energy and CNX Gas Company had a net (payable) receivable of $(638) and $8,966, respectively, which were comprised of the following items:

	September, 30 2012	December 31, 2011	Location on Balance Sheet
CONE Gathering Capital Reimbursement	$ 1,422	$ 8,042	Accounts Receivable–Other
Reimbursement for CONE Expenses	263	2,009	Accounts Receivable–Other
Reimbursement for Services Provided to CONE	61	414	Accounts Receivable–Other
CONE Gathering Fee Payable	(2,384)	(1,499)	Accounts Payable
Net (Payable) Receivable due CONE	$ (638)	$ 8,966	

NOTE 17—RECENT ACCOUNTING PRONOUNCEMENTS:

In July 2012, the Financial Accounting Standards Board issued Update 2012-2 - Intangibles - Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment. The update is intended to reduce the cost and complexity of performing an impairment test for indefinite-lived intangible assets by simplifying how an entity tests those assets for impairment. The update is also intended to improve the consistency in impairment testing guidance among long-lived asset categories. Previous guidance required an entity to test indefinite-lived intangible assets for impairment by comparing the fair value of the asset with its carrying amount at least on an annual basis. If the carrying amount exceeded its fair value, an entity needed to recognize an impairment loss in the amount of the excess. The amendment to this update allows an entity to first assess the qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. This assessment will determine whether it is necessary to perform quantitative impairment tests. This type of testing results in guidance that is similar to the goodwill impairment testing in Update 2011-08. The amendments are effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012 with early adoption permitted for impairment tests performed as of July 27, 2012. We believe adoption of this new guidance will not have a material impact on CONSOL Energy's financial statements.

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

General

During the third quarter, the domestic coal and natural gas industries took steps to recover from the challenges of the past year. Although flat electric demand growth and global economic uncertainties persisted, more disciplined production from coal and natural gas producers and favorable weather helped reduce inventories and stabilize prices. The domestic thermal coal industry continues to work through the effects of low gas prices and the unusually warm 2011-2012 winter. Third quarter coal consumption was aided by above average temperatures in July. As natural gas prices began to rise above $3.00 per thousand cubic feet, more electric generation switched back to its traditional coal-fired generators. Early government estimates show that coal-fired generation produced 39% of the U.S. power generation sector during the third quarter compared with 42% during the same period in 2011. This third quarter figure is a 3% increase from the second quarter of 2012. The percentage remained constant between quarters two and three of 2011. Utility coal stockpiles also declined throughout the quarter versus earlier 2012 periods. Warmer summer temperatures, a rise in natural gas prices, and domestic coal production cuts began to stabilize coal prices.

In the longer term, the outlook for domestic thermal coal faces regulatory challenges. Even though policies continue to evolve and develop, they ultimately tend to favor greater adoption of natural gas-fired generation. Specifically, the Environmental Protection Agency (EPA) was forced to redefine the Cross-State Air Pollution Rule (CSAPR) after a federal circuit court overturned the proposed regulation. The CSAPR decision notwithstanding, few new coal plants are expected to be built and utilities will continue to retire smaller and less efficient units. Internationally, although Europe has continued to use cheaper coal for electric generation, U.S. thermal exports have faced foreign competition from Colombian and South African coals.

Also during the third quarter, metallurgical benchmark prices remained below the comparable 2011 period. Although the U.S. third quarter international settlement price for premium metallurgical coal increased 7% above the U.S. second quarter settlement, the benchmark has already settled lower for the U.S. fourth quarter. The continued low price environment is underscored by the resumption of Australian production and a slowdown of Chinese economic growth.

CONSOL Energy's coal sales outlook as of October 25, 2012 is as follows:

	Q4 2012	2012	2013	2014
Estimated Coal Sales (millions of tons)	14.0	55.9	56.7	61.8
Est. Low-Vol Met Sales	0.6	3.4	3.9	4.9
Tonnage: Firm	0.6	3.4	1.1	—
Avg. Price: Sold (Firm)	$134.64	$141.72	$130.35	$—
Est. High-Vol Met Sales	0.5	3.4	2.7	4.8
Tonnage: Firm	0.5	3.4	0.3	0.3
Avg. Price: Sold (Firm)	$81.07	$65.46	$73.23	$75.53
Est. Thermal Sales	12.9	49.1	49.5	51.4
Tonnage: Firm	12.6	48.8	35.9	14.9
Avg. Price: Sold (Firm)	$61.21	$61.66	$60.63	$62.27

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 has chosen not to forecast prices for open tonnage due to ongoing customer negotiations. In the thermal sales category, the open tonnage includes two items: sold, but unpriced tons and collared tons. Collared tons in 2013 are 3.0 million tons, with a ceiling of $52.37 per ton and a floor of $47.37 per ton. Collared tons in 2014 are 7.0 million tons, with a ceiling of $55.90 per ton and a floor of $46.32 per ton. For 2013, when unpriced thermal tons are combined with collared tons, less than 2 million tons remains to be sold. Total Amonate estimated coal sales for Q4 2012 are 0.03 million tons. Calendar years 2012, 2013, and 2014 include 0.03, 0.6, and 0.7 million tons, respectively, from Amonate. The Amonate tons are not included in the category breakdowns.

Global steel demand has been under pressure and as a consequence, raw materials used to make steel are in less demand. In response to the weak market conditions related to raw materials used in steel making throughout its export markets in Asia, Europe, and South America, CONSOL Energy idled its Buchanan Mine and its Amonate Complex in early September 2012. The Buchanan Mine is expected to restart the week of November 5 with a five-day work week schedule, while Amonate is likely to remain idled for the remainder of 2012. Buchanan Mine typically produces approximately 400 thousand tons per month, while Amonate was expected to produce about 35 thousand tons per month.

On July 27, 2012 a structural failure occurred at CONSOL Energy's 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. This incident caused a total of four longwalls to be idled for approximately three weeks, at which point one rebuilt conveyor belt was re-started. Production from these mines was at approximately 60% of normal for most of the remainder of the third quarter. The company's third quarter net income would have been an estimated $53 million higher, had the conveyor belt incident not occurred. This impact is before the receipt of any insurance proceeds and any other proceeds under the indemnity provisions of the construction contract. Much lower sales from the company's flagship low-vol Buchanan Mine also reduced third quarter profitability, as the company chose not to sell into a market that was experiencing an inventory de-stocking.
In response to current weak market conditions for domestic coal, CONSOL Energy extended the annual miners' vacation period at its Blacksville No. 2 Mine and Robinson Run mines in Northern West Virginia. The Blacksville No. 2 Mine 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 Mine was restarted the week of July 22, 2012. The Robinson Run Mine extension was one week. Work was completed during the week extension to maintain the mine in a ready state. The longwall at Robinson Run Mine restarted the week of July 16, 2012. The extended vacation periods reduced total annual Company production by an estimated 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 were effective on September 1, 2012. Regular production from underground operations was idled on September 1, 2012. 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 reduced total annual Company production by approximately 800 thousand tons.
Due to market conditions, 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.
Natural gas prices improved throughout the third quarter as horizontal gas targeted rigs deployed throughout the country dropped and storage levels, although still elevated, began to align more closely with the five year average. While production remains higher on a year over year basis, natural gas pricing has risen based on improving fundamentals and favorable weather. CONSOL Energy expects its 2012 net gas production to be between 157 - 159 Bcf. Fourth quarter 2012 gas production, net to CONSOL Energy, is expected to be approximately 42.5 - 44.5 Bcf.

The following developments impacting CONSOL Energy occurred in the nine months ended September 30, 2012:

- On October 30, 2012, CONSOL Energy Inc. issued notice under the Worker Adjustment and Retraining Notification Act (WARN) of its intent to idle its Miller Creek surface operations near Naugatuck, W. Va., resulting in a layoff impacting approximately 145 employees. Production from the Miller Creek surface operations was 1.2 million tons for the nine months ended September 30, 2012. The idling of the Miller Creek operations is due to a sequence of permit delays that has prevented the company from securing all of the necessary environmental permits required to continue mining as identified in the company's mine plan.

- In June 2012, CONSOL Energy announced that it acquired a non controlling 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 purification system. The pilot test began in July with initial results expected in before the end of the year.

- 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 $6.3 million reduction in OPEB expense compared to what was originally expected to be recognized for the nine months ended September 30, 2012. Additionally, the change will result in a $3.1 million reduction to OPEB expense compared to what was originally expected to be recognized for the remaining three 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. This amount was paid in September 2012.

- In April 2012, CONSOL Energy sold its non-producing Elk Creek reserves in southern West Virginia. The transaction resulted in cash proceeds of $26 million and a gain on sale of assets of $11 million. In February 2012, CONSOL Energy sold it's non-producing Burning Star #4 reserves in Illinois. The transaction resulted in cash proceeds of $13 million and a gain on sale of assets of $11 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 chlorides 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 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), SO_2 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 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. On June 5, 2012, the West Virginia Department of Environmental Protection issued an Administrative Order to Fola. Fola is complying with the Administrative Order. On September 4, 2012, the citizens group filed a complaint against Fola in the U.S District Court for the Southern District of West Virginia covering the same matters addressed in the State Administrative Order.

- 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. If ultimately required, 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 September 30, 2012 Compared with Three Months Ended September 30, 2011

Net Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported net loss of $11 million, or $0.05 per diluted share, for the three months ended September 30, 2012. Net income was $167 million, or $0.73 per diluted share, for the three months ended September 30, 2011.
The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $4 million of earnings before income tax for the three months ended September 30, 2012 compared to $269 million for the three months ended September 30, 2011. The coal division sold 12.3 million tons of coal produced from CONSOL Energy mines for the three months ended September 30, 2012 compared to 14.7 million tons for the three months ended September 30, 2011.
The average sales price and average costs per ton for all active coal operations were as follows:

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per ton sold	$67.31	$76.60	$(9.29)	(12.1)%
Average Costs per ton sold	55.84	54.35	1.49	2.7%
Margin	$11.47	$22.25	$(10.78)	(48.4)%

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 higher thermal coal average prices as a result of several successful re-negotiations of domestic thermal contracts where pricing took effect on January 1, 2012. The decreased sales tonnage is due to decreased coal demand in both thermal and metallurgical markets and curtailed shipments due to the Bailey Belt incident discussed previously.

Changes in the average cost of goods sold per ton were primarily related to the following items:

- Average cost of goods sold per ton increased due to fewer tons sold. Fixed costs are allocated over fewer sales tons, resulting in higher unit costs.
- Average labor and labor-related costs per ton sold increased as a result of the impact of the $1.00 per hour worked United Mine Workers of America (UMWA) contract wage increases, offset, in part, by fewer hours worked.
- Average depreciation, depletion and amortization per ton sold increased due to additional assets placed into service after the 2011 period.
- Average retirement and disability costs per ton sold 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 $12 million of earnings before income tax for the three months ended September 30, 2012. The total gas division did not contribute a significant amount to earnings for the three months ended September 30, 2011. Total gas production was 39.5 billion cubic feet for the three months ended September 30, 2012 compared to 40.4 billion cubic feet for the three months ended September 30, 2011. Total gas sales decreased as a result of a decrease of 4.5 billion net cubic feet of production related to both the 2011 divestiture of Antero Resources Appalachian Corp. (Antero) and the 2011 Noble Joint Venture. Total production also decreased as a result of the Buchanan Mine idling as previously discussed. These decreases were 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.

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

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	$4.19	$4.92	$(0.73)	(14.8)%
Average Costs per thousand cubic feet sold	3.38	3.60	(0.22)	(6.1)%
Margin	$0.81	$1.32	$(0.51)	(38.6)%

Total gas division outside sales revenue was $165 million for the three months ended September 30, 2012 compared to $199 million for the three months ended September 30, 2011. The $34 million decrease was primarily due to the 14.8% 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 19.3 billion cubic feet of produced gas sales volumes for the three months ended September 30, 2012 at an average price of $5.25 per thousand cubic feet. These financial hedges represented 23.9 billion cubic feet of produced gas sales volumes for the three months ended September 30, 2011 at an average price of $5.12 per thousand cubic feet.

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

- Lower lifting costs that were the result of decreased road maintenance, decreased well fishing and well tending 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 direct administrative, selling and other costs per unit attributable to decreased actual dollars as a result of a reduction in direct administrative labor and other costs.
- Gathering costs increased 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.

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 September 30,			
	2012	2011	Variance	Percent Change
Employee wages and related expenses	$14	$17	$(3)	(17.6)%
Consulting and professional services	8	9	(1)	(11.1)%
Contributions	1	4	(3)	(75.0)%
Miscellaneous	10	10	—	—%
Total Company General and Administrative Expenses	$33	$40	$(7)	(17.5)%

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

- Employee wages and related expenses decreased $3 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. Additionally, an other post employment benefit plan modification for certain salaried employees lowered expenses.
- Consulting and professional services decreased $1 million in the period-to-period comparison primarily due to a reduction in CONSOL Energy's advertising and promotion campaign.
- Contributions decreased $3 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.
- Miscellaneous general and administrative expenses were consistent 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 $64 million for the three months ended September 30, 2012 compared to $83 million for the three months ended September 30, 2011. The decrease of $19 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 September 30, 2012 compared to the three months ended September 30, 2011:

The coal segment contributed $4 million of earnings before income tax for the three months ended September 30, 2012 compared to $269 million for the three months ended September 30, 2011. Variances by the individual coal segments are discussed below.

	For the Three Months Ended September 30, 2012					Difference to Three Months Ended September 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	$667	$48	$110	$—	$825	$(65)	$(35)	$(198)	$(8)	$(306)
Purchased Coal	—	—	—	5	5	—	—	—	—	—
Total Outside Sales	667	48	110	5	830	(65)	(35)	(198)	(8)	(306)
Freight Revenue	—	—	—	27	27	—	—	—	(33)	(33)
Other Income	1	1	—	18	20	—	(2)	—	(6)	(8)
Total Revenue and Other Income	668	49	110	50	877	(65)	(37)	(198)	(47)	(347)
Costs and Expenses:										
Beginning inventory costs	109	2	26	—	137	18	2	11	—	31
Total direct costs	333	22	45	74	474	(42)	(15)	(9)	41	(25)
Total royalty/production taxes	45	2	7	—	54	(4)	(2)	(10)	(2)	(18)
Total direct services to operations	51	5	6	65	127	(15)	(2)	—	8	(9)
Total retirement and disability	40	3	7	9	59	(17)	(2)	(4)	5	(18)
Depreciation, depletion and amortization	67	5	9	15	96	(8)	(2)	—	11	1
Ending inventory costs	(67)	—	(33)	(1)	(101)	15	—	(25)	(1)	(11)
Total Costs and Expenses	578	39	67	162	846	(53)	(21)	(37)	62	(49)
Freight Expense	—	—	—	27	27	—	—	—	(33)	(33)
Total Costs	578	39	67	189	873	(53)	(21)	(37)	29	(82)
Earnings (Loss) Before Income Taxes	$90	$10	$43	$(139)	$4	$(12)	$(16)	$(161)	$(76)	$(265)

THERMAL COAL SEGMENT

The thermal coal segment contributed $90 million to total Company earnings before income tax for the three months ended September 30, 2012 compared to $102 million for the three months ended September 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 September 30,			
	2012	2011	Variance	Percent Change
Company Produced Thermal Tons Sold (in millions)	10.7	12.2	(1.5)	(12.3)%
Average Sales Price Per Thermal Ton Sold	$62.11	$60.18	$1.93	3.2%
Beginning Inventory Costs Per Thermal Ton	$56.03	$56.92	$(0.89)	(1.6)%
Total Direct Operating Costs Per Thermal Ton Produced	$33.05	$30.91	$2.14	6.9%
Total Royalty/Production Taxes Per Thermal Ton Produced	4.46	4.07	0.39	9.6%
Total Direct Services to Operations Per Thermal Ton Produced	5.06	5.44	(0.38)	(7.0)%
Total Retirement and Disability Per Thermal Ton Produced	4.04	4.70	(0.66)	(14.0)%
Total Depreciation, Depletion and Amortization Costs Per Thermal Ton Produced	6.70	6.22	0.48	7.7%
Total Production Costs Per Thermal Ton Produced	$53.31	$51.34	$1.97	3.8%
Ending Inventory Costs Per Thermal Ton	$51.55	$52.89	$(1.34)	(2.5)%
Total Costs Per Thermal Ton Sold	$53.81	$51.94	$1.87	3.6%
Average Margin Per Thermal Ton Sold	$8.30	$8.24	$0.06	0.7%

Thermal coal revenue was $667 million for the three months ended September 30, 2012 compared to $732 million for the three months ended September 30, 2011. The $65 million decrease was attributable to a 1.5 million reduction in thermal tons sold offset, in part, by a $1.93 per ton higher average sales price. The sales ton decrease was primarily due to the July 27, 2012 structural failure of the above-ground conveyor system at the Bailey Preparation Plant. The incident curtailed shipments of production from both Bailey Mine and the Enlow Fork Mine during the reconstruction period as previously discussed. Thermal coal average sales price per ton were higher in the period-to-period comparison as a result of several successful re-negotiations of domestic thermal contracts whose pricing took effect on January 1, 2012.

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.

Total cost of goods sold are comprised of changes in thermal coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for thermal coal was $578 million for the three months ended September 30, 2012, or $53 million lower than the $631 million for the three months ended September 30, 2011. Although total cost of goods sold dollars were improved, total costs per ton sold was impaired. Total costs of goods sold for thermal coal was $53.81 per ton in the three months ended September 30, 2012 compared to $51.94 per ton in the three months ended September 30, 2011. The increase in cost of goods sold per thermal ton produced were due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power 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. Direct Operating costs related to the thermal coal segment were $333 million in the three months ended September 30, 2012 compared to $375 million in the three months ended September 30, 2011.

Direct operating costs dollars are improved due to lower tons produced in the period-to-period comparison and cost control measures implemented. Although improved $42 million, the cost improvements did not completely offset the impact of reduced production on unit costs. Direct operating costs were $33.05 per ton produced in the current period compared to $30.91 per ton produced in the prior period. Changes in the average direct operating costs per thermal ton produced were primarily related to the following items:

- Average operating costs per thermal ton produced increased due to fewer tons produced. Fixed costs are allocated over less tons, resulting in higher unit costs.
- Labor and related benefits average costs per thermal ton produced increased. This was primarily due to the impact of the wage increases of $1.00 per hour worked related to the UMWA collective bargaining agreement in the period-to-period comparison, offset, in part, by fewer overtime hours worked.
- Various other unit costs including supplies, maintenance, power and miscellaneous costs did not significantly change individually or in total.

Royalties and production taxes were $45 million in the three months ended September 30, 2012 compared to $49 million in the three months ended September 30, 2011. Although improved $4 million, these costs were impaired on a unit basis. Average cost per thermal ton produced increased $0.39 per ton due to lower production volumes and higher average sales prices which is the basis for most production taxes and royalty calculations.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The cost of these support services were $51 million in the current period compared to $66 million in the prior year period. Direct services to the operations were $5.06 per ton in the current period compared to $5.44 per ton in the prior period. Changes in the average direct services to operations cost per ton for thermal coal sold were primarily related to the following items:

- Subsidence average cost per thermal ton produced is lower in the period-to-period comparison due to the timing and quantity of structures undermined. Also, subsidence expense is lower in the current period due to less streams being undermined compared to the prior year quarter.
- Unit costs were also improved due to various other items, none of which were individually material.
- Average direct service costs to operations were impaired due to lower thermal tons produced in the period-to-period comparison which negatively impacted unit costs.

Retirement and disability costs are comprised of the expenses related to the Company's long-term liabilities, such as other OPEB, the salary retirement plan, workers' compensation, coal workers' pneumoconiosis (CWP) and long-term disability. 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. The average retirement and disability costs attributable to the thermal coal segment were $40 million for the three months ended September 30, 2012 compared to $57 million for the three months ended September 30, 2011. The decrease in the thermal coal retirement and disability costs 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 production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the thermal coal segment was $67 million for the three months ended September 30, 2012 compared to $75 million for the three months ended September 30, 2011. The decrease was primarily due to lower depletion directly related to lower production volumes. Unit costs per thermal ton produced were higher in the three months ended September 30, 2012 compared to the three months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis.

Changes in thermal coal inventory volumes and carrying value resulted in $42 million of cost of goods sold in the three months ended September 30, 2012 compared to $9 million in the three months ended September 30, 2011. Thermal coal inventory was 1.3 million tons at September 30, 2012 compared to 1.6 million tons at September 30, 2011.

HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $10 million to total Company earnings before income tax for the three months ended September 30, 2012 compared to $26 million for the three months ended September 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 September 30,			
	2012	2011	Variance	Percent Change
Company Produced High Vol Met Tons Sold (in millions)	0.7	1.0	(0.3)	(30.0)%
Average Sales Price Per High Vol Met Ton Sold	$67.76	$82.21	$(14.45)	(17.6)%
Beginning Inventory Costs Per High Vol Met Ton	$63.50	$—	$63.50	—%
Total Direct Operating Costs Per High Vol Met Ton Produced	$30.10	$36.19	$(6.09)	(16.8)%
Total Royalty/Production Taxes Per High Vol Met Ton Produced	3.09	4.11	(1.02)	(24.8)%
Total Direct Services to Operations Per High Vol Met Ton Produced	7.26	7.33	(0.07)	(1.0)%
Total Retirement and Disability Per High Vol Met Ton Produced	3.89	5.43	(1.54)	(28.4)%
Total Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Produced	7.38	7.22	0.16	2.2%
Total Production Costs Per High Vol Met Ton Produced	$51.72	$60.28	$(8.56)	(14.2)%
Ending Inventory Costs Per High Vol Met Ton	$—	$—	$—	—%
Total Costs Per High Vol Met Ton Sold	$55.29	$60.28	$(4.99)	(8.3)%
Margin Per High Vol Met Ton Sold	$12.47	$21.93	$(9.46)	(43.1)%

High volatile metallurgical coal revenue was $48 million for the three months ended September 30, 2012 compared to $83 million for the three months ended September 30, 2011. Average sales prices for high volatile metallurgical coal decreased $14.45 per ton compared to the three months ended September 30, 2011 due to weakened global metallurgical coal demand. CONSOL Energy priced 0.6 million tons of high volatile metallurgical coal in the export market at an average sales price of $65.96 per ton for the three months ended September 30, 2012 compared to 0.8 million tons at an average price of $80.65 per ton for the three months ended September 30, 2011. The remaining tons sold in the period-to-period comparison were sold on the domestic market.

Total cost of goods sold are comprised of changes in high volatile metallurgical coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for high volatile metallurgical coal was $39 million for the three months ended September 30, 2012, or $21 million lower than the $60 million for the three months ended September 30, 2011. Total cost of goods sold for high volatile metallurgical coal was $55.29 per ton in the three months ended September 30, 2012 compared to $60.28 per ton in the three months ended September 30, 2011. The decrease in cost of goods sold per high volatile metallurgical ton was due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power 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. Direct Operating costs related to the high volatile metallurgical coal segment were $22 million in the three months ended September 30, 2012 compared to $37 million in the three months ended September 30, 2011. Direct operating costs were $30.10 per ton produced in the current period compared to $36.19 per ton produced in the prior period. Changes in the average direct operating costs per ton for high volatile metallurgical coal sold were primarily related to the mix of mines which sold on the high volatile metallurgical coal market in the period-to-period comparison. Mines with higher cost structures produced a larger portion of the high volatile metallurgical coal shipped in the prior period compared to the current period. This resulted in lower direct operating costs in the period-to-period comparison. The impact of the improvements on unit costs were offset, in part, by lower tons sold which negatively impacted unit costs.

Royalties and production taxes improved $2 million to $2 million in the current period compared to $4 million in the prior period. Unit costs also improved $1.02 per high volatile metallurgical ton produced to $3.09 per ton in the current period compared to $4.11 per ton in the prior period. Average cost per high volatile metallurgical ton produced decreased due to lower production taxes related to lower average sales prices.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The costs of these support services for high volatile metallurgical coal were $5 million in the current period compared to $7 million in the prior period. The improvement was due primarily to lower direct administrative costs and subsidence costs. Direct services to the operations for high volatile metallurgical coal were $7.26 per ton in the current period compared to $7.33 per ton in the prior period. These improvements lowered unit costs, but were offset in part by lower tons produced in the period-to-period comparison.

Retirement and disability 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, coal workers' pneumoconiosis (CWP) and long-term disability. 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. The average retirement and disability costs attributable to the high volatile metallurgical coal segment were $3 million for the three months ended September 30, 2012 compared to $5 million for the three months ended September 30, 2011. The decrease in the high volatile metallurgical coal retirement and disability costs 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 production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the high volatile metallurgical coal segment was $5 million for the three months ended September 30, 2012 compared to $7 million for the three months ended September 30, 2011. The decrease was primarily due to lower depletion directly related to lower production volumes. Unit costs per high volatile ton produced were higher in the three months ended September 30, 2012 compared to the three months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis.

Changes in high volatile metallurgical coal inventory volumes and carrying value resulted in $2 million of cost of goods sold in the three months ended September 30, 2012. There were no changes in volumes or carrying value in the three months ended September 30, 2011. There was no high volatile metallurgical coal inventory at September 30, 2012 or September 30, 2011.

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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 September 30, 2012 compared to $204 million for the three months ended September 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 September 30,			
	2012	2011	Variance	Percent Change
Company Produced Low Vol Met Tons Sold (in millions)	0.8	1.4	(0.6)	(42.9)%
Average Sales Price Per Low Vol Met Ton Sold	$135.66	$207.21	$(71.55)	(34.5)%
Beginning Inventory Costs Per Low Vol Met Ton	$69.84	$66.09	$3.75	5.7 %
Total Direct Operating Costs Per Low Vol Met Ton Produced	$55.60	$39.28	$16.32	41.5 %
Total Royalty/Production Taxes Per Low Vol Met Ton Produced	8.75	12.42	(3.67)	(29.5)%
Total Direct Services to Operations Per Low Vol Met Ton Produced	6.83	4.46	2.37	53.1 %
Total Retirement and Disability Per Low Vol Met Ton Produced	8.63	7.58	1.05	13.9 %
Total Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Produced	11.29	6.73	4.56	67.8 %
Total Production Costs Per Low Vol Met Ton Produced	$91.10	$70.47	$20.63	29.3 %
Ending Inventory Costs Per Low Vol Met Ton	$87.32	$67.35	$19.97	29.7 %
Total Costs Per Low Vol Met Ton Sold	$83.09	$70.08	$13.01	18.6 %
Margin Per Low Vol Met Ton Sold	$52.57	$137.13	$(84.56)	(61.7)%

Low volatile metallurgical coal revenue was $110 million for the three months ended September 30, 2012 compared to $308 million for the three months ended September 30, 2011. The $198 million decrease was attributable to the 0.6 million decrease in sales tons and a $71.55 per ton decrease in average sales price. CONSOL Energy priced 0.6 million tons of low volatile metallurgical coal in the export market at an average sales price of $114.26 per ton for the three months ended September 30, 2012 compared to 1.2 million tons at an average price of $214.74 per ton for the three months ended September 30, 2011. The remaining tons sold in the period-to-period comparison were sold on the domestic market.

Total cost of goods sold are comprised of changes in low volatile metallurgical coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for low volatile metallurgical coal was $67 million for the three months ended September 30, 2012, or $37 million lower than the $104 million for the three months ended September 30, 2011. Total cost of goods sold for low volatile metallurgical coal was $83.09 per ton in the three months ended September 30, 2012 compared to $70.08 per ton in the three months ended September 30, 2011. The increase in costs of goods sold per low volatile metallurgical ton was due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power 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. Direct Operating costs related to the low volatile metallurgical coal segment were $45 million in the three months ended September 30, 2012 compared to $54 million in the three months ended September 30, 2011. Direct operating costs dollars are improved due to lower tons produced in the period-to-period comparison and cost control measures implemented. Although improved $9 million, the cost improvements did not completely offset the impact of reduced production on unit costs. Direct operating costs were $55.60 per ton produced in the current period compared to $39.28 per ton produced in the prior period. Low volatile metallurgical coal production was 0.8 million tons in the three months ended September 30, 2012 compared to 1.4 million tons in the three months ended September 30, 2011. Production was lower in the period-to-period comparison due to the Buchanan Mine being idled in early September. The mine was idled in response to the weak world economy. Fixed costs were then spread over fewer tons produced which increased all costs on a per unit basis.

Royalties and production taxes improved $10 million to $7 million in the current period compared to $17 million in the prior period. Unit costs also improved $3.67 per low volatile metallurgical ton produced to $8.75 per ton in the current period compared to $12.42 per ton in the prior period. Average cost per low volatile metallurgical ton produced decreased due to lower royalties and lower production taxes. These decreases were related to lower volumes produced and lower average sales prices.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The costs of these support services for low volatile metallurgical coal were $6 million in both the current and prior periods. Direct services to the operations for low volatile metallurgical coal were $6.83 per ton in the current period compared to $4.46 per ton in the prior period. Changes in the average direct service to operations cost per ton for low volatile metallurgical coal produced were primarily related to lower tons produced in the period-to-period comparison.

Retirement and disability 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, coal workers' pneumoconiosis (CWP) and long-term disability. 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. The retirement and disability costs attributable to the low volatile metallurgical coal segment were $7 million for the three months ended September 30, 2012 compared to $11 million for the three months ended September 30, 2011. The decrease in the low volatile metallurgical retirement and disability costs 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 production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the low volatile metallurgical coal segment was $9 million for both the three months ended September 30, 2012 and 2011. Unit costs per low volatile metallurgical ton produced were higher in the three months ended September 30, 2012 compared to the three months ended September 30, 2011 due to lower tons produced.

Changes in low volatile metallurgical coal inventory volumes and carrying value resulted in a reduction of $7 million to cost of goods sold in the three months ended September 30, 2012 and an increase of $7 million to cost of goods sold in the three months ended September 30, 2011. Produced low volatile metallurgical coal inventory was 0.4 million tons at September 30, 2012 compared to 0.1 million tons at September 30, 2011.

OTHER COAL SEGMENT

The other coal segment had a loss before income tax of $139 million for the three months ended September 30, 2012 compared to a loss before income tax of $63 million for the three months ended September 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.

Produced coal sales include revenue from the sale of less than 0.1 million tons for the three months ended September 30, 2012 compared to 0.1 million tons for the three months ending September 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 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 and coal purchased from third parties and sold directly to our customers. The revenues were $5 million for the three months ended September 30, 2012 and September 30, 2011.

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 $27 million for the three months ended September 30, 2012 compared to $60 million for the three months ended September 30, 2011. The $33 million decrease in freight revenue is due to decreased shipments on contracts for which CONSOL Energy contractually provides transportation services.

Miscellaneous other income was $18 million for the three months ended September 30, 2012 compared to $24 million for the three months ended September 30, 2011. Other revenue in the three months ended September 30, 2011 includes a gain of $10 million for the issuance of a pipeline right-of-way to a third party. This impairment was offset by $5 million of income from certain thermal coal contract buyouts received during the three months ended September 30, 2012. Various other transactions, which occurred throughout both periods, none of which were individually material, resulted in an impairment of $1 million.

Other coal segment total costs were $189 million for the three months ended September 30, 2012 compared to $160 million for the three months ended September 30, 2011. The increase of $29 million was due to the following items:

	For the Three Months Ended September 30,		
	2012	2011	Variance
Bailey Belt Incident	$42	$—	$42
Closed and idle mines	40	23	17
Purchased coal	11	10	1
Freight expense	27	60	(33)
Other	69	67	2
Total Other Coal Segment Costs	$189	$160	$29

- Bailey Belt Incident costs represent expenses for various projects that were incurred during the belt-reconstruction period related to continued advancement of the mines and on-going projects at the mines.
- Closed and idle mine costs increased approximately $17 million for the three months ended September 30, 2012 compared to the three months ended September 30, 2011. Closed and idle mine costs increased $11 million due to the decision to idle operations at Fola Surface and $7 million due to the decision to idle operations at Buchanan Mine during September 2012. Closed and idle mine costs decreased $1 million due to other changes in operational status of various other mines, between idled and operating throughout both periods, none of which were individually material.
- Purchased coal costs increased approximately $1 million in the period-to-period comparison due to various items, none of which were individually material.
- 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 $33 million primarily due to decreased shipments on contracts for which CONSOL Energy contractually provides transportation services.
- Other expenses related to the coal segment increased $2 million in the period-to-period comparison due to various transactions which occurred throughout both periods, none of which were individually material.

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

The total gas segment contributed $12 million to the total Company earnings before income tax for the three months ended September 30, 2012. The gas segment did not significantly contribute to earnings before income tax for the three months ended September 30, 2011.

	For the Three Months Ended September 30, 2012					Difference to Three Months Ended September 30, 2011				
	CBM	Shallow Oil & Gas	Marcellus	Other Gas	Total Gas	CBM	Shallow Oil & Gas	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$94	$32	$36	$2	$164	$(23)	$(7)	$(3)	$—	$(33)
Related Party	1	—	—	—	1	(1)	—	—	—	(1)
Total Outside Sales	95	32	36	2	165	(24)	(7)	(3)	—	(34)
Gas Royalty Interest	—	—	—	13	13	—	—	—	(4)	(4)
Purchased Gas	—	—	—	1	1	—	—	—	—	—
Other Income	—	—	—	12	12	—	—	—	26	26
Total Revenue and Other Income	95	32	36	28	191	(24)	(7)	(3)	22	(12)
Lifting	9	10	3	—	22	(1)	(5)	(3)	—	(9)
Ad Valorem, Severance, and Other Taxes	2	2	1	2	7	(1)	—	1	1	1
Gathering	27	6	7	1	41	2	(2)	4	1	5
Gas Direct Administrative, Selling & Other	3	3	6	(1)	11	(5)	(2)	3	—	(4)
Depreciation, Depletion and Amortization	23	14	13	2	52	(3)	(1)	(2)	—	(6)
General & Administration	—	—	—	10	10	—	—	—	(3)	(3)
Gas Royalty Interest	—	—	—	11	11	—	—	—	(5)	(5)
Purchased Gas	—	—	—	1	1	—	—	—	1	1
Exploration and Other Costs	—	—	—	7	7	—	—	—	1	1
Other Corporate Expenses	—	—	—	16	16	—	—	—	(4)	(4)
Interest Expense	—	—	—	1	1	—	—	—	(1)	(1)
Total Cost	64	35	30	50	179	(8)	(10)	3	(9)	(24)
Earnings Before Income Tax	$31	$(3)	$6	$(22)	$12	$(16)	$3	$(6)	$31	$12

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COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $31 million to total Company earnings before income tax for the three months ended September 30, 2012 compared to $47 million for the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas CBM sales volumes (in billion cubic feet)	21.7	23.3	(1.6)	(6.9)%
Average CBM sales price per thousand cubic feet sold	$4.36	$5.04	$(0.68)	(13.5)%
Average CBM lifting costs per thousand cubic feet sold	0.41	0.41	—	—%
Average CBM ad valorem, severance, and other taxes per thousand cubic feet sold	0.11	0.13	(0.02)	(15.4)%
Average CBM gathering costs per thousand cubic feet sold	1.26	1.06	0.20	18.9%
Average CBM direct administrative, selling & other costs per thousand cubic feet sold	0.11	0.33	(0.22)	(66.7)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	1.03	1.10	(0.07)	(6.4)%
Total Average CBM costs per thousand cubic feet sold	2.92	3.03	(0.11)	(3.6)%
Average Margin for CBM	$1.44	$2.01	$(0.57)	(28.4)%

CBM sales revenues were $95 million for the three months ended September 30, 2012 compared to $119 million for the three months ended September 30, 2011. The $24 million decrease was primarily due to a 13.5% decrease in average sales price per thousand cubic feet sold, as well as a 6.9% 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 11.4 billion cubic feet of produced CBM gas sales volumes for the three months ended September 30, 2012 at an average price of $5.34 per thousand cubic feet. For the three months ended September 30, 2011, these financial hedges represented 16.6 billion cubic feet at an average price of $5.27 per thousand cubic feet. CBM sales volumes decreased 1.6 billion cubic feet for the three months ended September 30, 2012 compared to the 2011 period primarily due to normal well declines without a corresponding increase in wells drilled and the Buchanan Mine idling, as previously discussed. Currently, the focus of the gas division is to develop its Marcellus and Utica acreage. At September 30, 2012, there were 4,493 gross CBM wells in production. At September 30, 2011, there were 4,397 gross CBM wells in production. Total costs for the CBM segment were $64 million for the three months ended September 30, 2012 compared to $72 million for the three months ended September 30, 2011. Lower costs in the period-to-period comparison were primarily related to lower unit costs as discussed below.

CBM lifting costs were $9 million in the three months ended September 30, 2012 compared to $10 million in the three months ended September 30, 2011. The $1 million decrease was due to lower road maintenance and lower contractor services in the period-to-period comparison. The average CBM lifting unit costs remained consistent in the period-to-period comparison.

CBM ad valorem, severance and other taxes were $2 million in the three months ended September 30, 2012 compared to $3 million in the three months ended September 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 $27 million for the three months ended September 30, 2012 compared to $25 million for the three months ended September 30, 2011. The $2 million increase and $0.20 increase in average per unit costs were due to increased power charges and increased pipeline maintenance. Also, the reduced sales volumes negatively impacted unit costs.

CBM direct administrative, selling & other costs for the CBM segment were $3 million for the three months ended September 30, 2012 compared to $8 million for the three months ended September 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 CBM volumes representing a smaller proportion of total natural gas volumes. Depreciation, depletion and amortization attributable to the CBM segment was $23 million for the three months ended September 30, 2012 compared to $26 million for the three months ended September 30, 2011. There was approximately $15 million, or $0.68 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 September 30, 2012. The production portion of depreciation, depletion and amortization was $18 million, or $0.77 per unit-of-production for the three months ended September 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 $8 million, or $0.35 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 September 30, 2012. There was $8 million, or $0.33 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 September 30, 2011.

SHALLOW OIL AND GAS SEGMENT

The Shallow Oil and Gas segment had a loss before income tax of $3 million in the three months ended September 30, 2012 compared to a loss before income tax of $6 million in the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas Shallow Oil and Gas sales volumes (in billion cubic feet)	7.0	7.8	(0.8)	(10.3)%
Average Shallow Oil and Gas sales price per thousand cubic feet sold	$4.59	$4.98	$(0.39)	(7.8)%
Average Shallow Oil and Gas lifting costs per thousand cubic feet sold	1.44	1.91	(0.47)	(24.6)%
Average Shallow Oil and Gas ad valorem, severance, and other taxes per thousand cubic feet sold	0.37	0.31	0.06	19.4%
Average Shallow Oil and Gas gathering costs per thousand cubic feet sold	0.87	1.00	(0.13)	(13.0)%
Average Shallow Oil and Gas direct administrative, selling & other costs per thousand cubic feet sold	0.35	0.63	(0.28)	(44.4)%
Average Shallow Oil and Gas depreciation, depletion and amortization costs per thousand cubic feet sold	2.05	1.94	0.11	5.7%
Total Average Shallow Oil and Gas costs per thousand cubic feet sold	5.08	5.79	(0.71)	(12.3)%
Average Margin for Shallow Oil and Gas	$(0.49)	$(0.81)	$0.32	(39.5)%

Shallow Oil and Gas sales revenues were $32 million for the three months ended September 30, 2012 compared to $39 million for the three months ended September 30, 2011. The $7 million decrease was primarily due to the 7.8% decrease in average sales price per thousand cubic feet sold. Shallow Oil and Gas sales volumes also decreased 10.3% for the three months ended September 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 its 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 September 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 4.9 billion cubic feet of produced Shallow Oil and Gas gas sales volumes for the three months ended September 30, 2012 at an average price of $5.23 per thousand cubic feet. In the three months ended September 30, 2011, these financial hedges represented 3.9 billion cubic feet at an average price of $4.94 per thousand cubic feet. At September 30, 2012, there were 9,936 gross Shallow Oil and Gas wells in production. At September 30, 2011, there were 10,015 gross Shallow Oil and Gas wells in production.

Total costs for the Shallow Oil and Gas segment were $35 million for the three months ended September 30, 2012 compared to $45 million for the three months ended September 30, 2011.

Shallow Oil and Gas lifting costs were $10 million for the three months ended September 30, 2012 compared to $15 million for three months ended September 30, 2011. Lifting costs per unit decreased $0.47 due to lower well tending costs, lower water disposal costs, lower road maintenance costs and lower costs associated with non-operated wells. These decreases were offset, in part, by lower volumes sold which negatively impacted unit costs.

Shallow Oil and Gas ad valorem, severance and other taxes were $2 million for the three months ended September 30, 2012 and 2011. The increase in average unit costs was primarily due to lower gas volumes sold in the period-to-period comparison.

Shallow Oil and Gas gathering costs were $6 million for the three months ended September 30, 2012 compared to $8 million for the three months ended September 30, 2011. Shallow Oil and Gas gathering average unit costs decreased primarily as a result of lower compressor maintenance charges, lower firm transportation charges, lower power charges, offset, in part, by lower volumes sold.

Shallow Oil and Gas direct administrative, selling & other costs were $3 million for the three months ended September 30, 2012 compared to $5 million for the three months ended September 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 reduced direct administrative labor and 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 September 30, 2012 compared to $15 million for the three months ended September 30, 2011. There was approximately $12 million, or $1.79 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 September 30, 2012. There was approximately $13 million, or $1.72 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 September 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 $0.26 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 September 30, 2012. There was $2 million, or $0.22 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 September 30, 2011.

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $6 million to the total Company earnings before income tax for the three months ended September 30, 2012 compared to $12 million for the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas Marcellus sales volumes (in billion cubic feet)	10.1	8.7	1.4	16.1 %
Average Marcellus sales price per thousand cubic feet sold	$3.58	$4.48	$(0.90)	(20.1)%
Average Marcellus lifting costs per thousand cubic feet sold	0.32	0.65	(0.33)	(50.8)%
Average Marcellus ad valorem, severance, and other taxes per thousand cubic feet sold	0.12	0.05	0.07	140.0 %
Average Marcellus gathering costs per thousand cubic feet sold	0.68	0.29	0.39	134.5 %
	0.55	0.34	0.21	61.8 %

Average Marcellus direct administrative, selling & other costs per thousand cubic feet sold				
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	1.28	1.72	(0.44)	(25.6)%
Total Average Marcellus costs per thousand cubic feet sold	2.95	3.05	(0.10)	(3.3)%
Average Margin for Marcellus	$0.63	$1.43	$(0.80)	(55.9)%

The Marcellus segment sales revenues were $36 million for the three months ended September 30, 2012 compared to $39 million for the three months ended September 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 3.0 billion cubic feet of produced Marcellus gas sales volumes for the three months ended September 30, 2012 at an average price of $4.97 per thousand cubic feet. These financial hedges represented 3.4 billion cubic feet of produced Marcellus gas sales volumes for the three months ended September 30, 2011 at an average price of $4.61 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 4.5 billion net cubic feet of production related to the 2011 Antero divestiture and 2011 Noble joint venture. At September 30, 2012, there were 194 gross Marcellus Shale wells in production. At September 30, 2011, there were 122 gross Marcellus Shale wells in production.

Marcellus lifting costs were $3 million for the three months ended September 30, 2012 compared to $6 million for the three months ended September 30, 2011. Lifting costs per unit decreased $0.33 per thousand cubic feet sold due to lower well tending costs and well service costs in the period-to-period comparison, combined with higher volumes sold.

Marcellus ad valorem, severance and other taxes were $1 million in the period ended September 30, 2012 compared to less than $1 million in the period ended September 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. The impact on unit costs of this increase was offset, in part, by higher volumes sold.

Marcellus gathering costs were $7 million for the three months ended September 30, 2012 compared to $3 million for the three months ended September 30, 2011. Average Marcellus gathering unit costs increased due to higher firm transportation costs and gathering costs associated with 1.4 billion cubic feet of additional volumes sold.

Marcellus direct administrative, selling & other costs related to the Marcellus gas segment were $6 million for the three months ended September 30, 2012 compared to $3 million for the three months ended September 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 increase in direct administrative, selling & other costs was primarily due to increased direct administrative labor and Marcellus volumes representing a higher proportion of total natural gas volumes.

Depreciation, depletion and amortization costs were $13 million for the three months ended September 30, 2012 compared to $15 million for the three months ended September 30, 2011. There was approximately $12 million, or $1.22 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 September 30, 2012. There was approximately $10 million, or $1.12 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 September 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 $0.06 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 September 30, 2012. There was $5 million, or $0.60 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 September 30, 2011. The decrease in Marcellus gathering and other equipment depreciation, depletion and amortization relates to the sale of assets to CONE Gathering LLC (CONE), a 50% owned affiliate. See Note 2 - Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional information.

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 and the Utica Shale in Ohio. Revenue from these operations were approximately $2 million for the three months ended September 30, 2012 and 2011. Total costs related to these other sales were $4 million in the 2012 period and $2 million in the 2011 period. The increase in costs is due to various transactions which occurred throughout both periods, none of which are individually material. A per unit analysis of the other operating costs in the Chattanooga Shale and the Utica 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 $13 million for the three months ended September 30, 2012 compared to $17 million for the three months ended September 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 September 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	4.8	3.9	0.9	23.1 %
Average Sales Price Per thousand cubic feet	$2.67	$4.34	$(1.67)	(38.5)%

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 both the three months ended September 30, 2012 and 2011.

	For the Three Months Ended September 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	$3.29	$4.43	$(1.14)	(25.7)%

Other income was $12 million for the three months ended September 30, 2012 compared to a loss of $14 million for the three months ended September 30, 2011. The $26 million increase was due primarily to a $58 million loss on the Noble transaction during 2011, partially offset by a gain on the sale of Antero overriding royalty interest of $41 million during 2011. Additionally, the increase is due to $8 million of additional interest income relating to the notes receivable from the Noble joint venture transaction. The additional $1 million increase is due to various other transactions that occurred throughout both periods, none of which are individually material.

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 $10 million for the three months ended September 30, 2012 compared to $13 million for the three months ended September 30, 2011. Refer to the discussion of total general and administrative costs contained in the section "Net Income" of this quarterly report for detailed cost explanations.

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 $11 million for the three months ended September 30, 2012 compared to $16 million for the three months ended September 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 September 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	4.8	3.9	0.9	23.1 %
Average Cost Per thousand cubic feet sold	$2.18	$3.92	$(1.74)	(44.4)%

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 higher 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 September 30, 2012 compared to less than $1 million for the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	0.2	0.2	—	— %

Average Cost Per thousand cubic feet sold	$3.04	$1.62	$1.42	87.7	%

Exploration and other costs were $7 million for the three months ended September 30, 2012 compared to $6 million for the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Lease Expiration Costs	$4	$4	$—	— %
Dry Hole Costs	—	2	(2)	(100.0)%
Exploration	3	—	3	100.0 %
Total Exploration and Other Costs	$7	$6	$1	16.7 %

- Lease Expiration costs were consistent in period-to-period comparison. Lease expiration costs relate to locations where CONSOL Energy allowed primary term leases to expire.
- Dry Hole Costs decreased $2 million due to additional dry hole wells in the 2011 period. There were no dry hole costs incurred during the three months ended September 30, 2012.
- Exploration expenses increased $3 million due to various transactions that occurred throughout both periods, none of which were individually material.

Other corporate expenses were $16 million for the three months ended September 30, 2012 compared to $20 million for the three months ended September 30, 2011. The $4 million decrease in the period-to-period comparison was made up of the following items:

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Contract Buyout	$—	$3	$(3)	(100.0)%
Short-term incentive compensation	5	6	(1)	(16.7)%
Stock-based compensation	4	5	(1)	(20.0)%
Unutilized firm transportation	4	4	—	— %
Bank fees	2	2	—	— %
Other	1	—	1	100.0 %
Total Other Corporate Expenses	$16	$20	$(4)	(20.0)%

- Contract Buyout represents the cancellation of a drilling arrangement with a third-party well driller.
- Short-term incentive compensation decreased $1 million in the period-to-period comparison. 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 activity 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 September 30, 2012 compared to $2 million for the three months ended September 30, 2011. The $1 million decrease in interest expense 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 September 30, 2012 compared to the three months ended September 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 $47 million for the three months ended September 30, 2012 compared to a loss before income tax of $68 million for the three months ended September 30, 2011. The other segment also included total company income tax benefit of ($20) million for the three months ended September 30, 2012 compared to expense of $33 million for the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Sales—Outside	$88	$88	$—	— %
Other Income	6	7	(1)	(14.3)%
Total Revenue	94	95	(1)	(1.1)%
Cost of Goods Sold and Other Charges	78	98	(20)	(20.4)%
Depreciation, Depletion & Amortization	6	5	1	20.0 %
Taxes Other Than Income Tax	3	3	—	— %
Interest Expense	54	57	(3)	(5.3)%
Total Costs	141	163	(22)	(13.5)%
Loss Before Income Tax	(47)	(68)	21	30.9 %
Income Tax	(20)	33	(53)	(160.6)%
Net Loss	$(27)	$(101)	$74	73.3 %

Industrial supplies:

Total revenue from industrial supplies was $59 million for the three months ended September 30, 2012 compared to $62 million for the three months ended September 30, 2011. The decrease was primarily related to lower sales volumes.

Total costs related to industrial supply sales were $56 million for the three months ended September 30, 2012 compared to $59 million for the three months ended September 30, 2011. The decrease of $3 million was primarily related to lower sales volumes and various changes in inventory costs, none of which were individually material.

Transportation operations:

Total revenue from transportation operations was $31 million for the three months ended September 30, 2012 compared to $29 million for the three months ended September 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 $23 million for the three months ended September 30, 2012 and $22 million for the three months ended September 30, 2011. The increase was due to various items in both periods, none of which were individually material.

Miscellaneous other:

Additional other income was $4 million for both the three months ended September 30, 2012 and 2011. The income is primarily related 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 $62 million for the three months ended September 30, 2012 compared to $82 million for the three months ended September 30, 2011. Other corporate costs decreased due to the following items:

	For the Three Months Ended September 30,		
	2012	2011	Variance
Transaction and financing fees	$—	$15	$(15)
Interest Expense	53	57	(4)
Bank Fees	3	6	(3)
Evaluation fees for non-core asset dispositions and other legal charges	3	2	1
Other	3	2	1
	$62	$82	$(20)

- 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 $15 million, which primarily represented the interest that would have been paid on these notes if held to maturity.
- Interest expense decreased $4 million primarily due to an increase in capitalized interest due to higher capital expenditures for major construction projects in the current period. These decreases were offset by an increase in uncertain tax positions interest expense.
- Bank fees decreased $3 million due to lower borrowings on the revolving credit facilities in the period-to-period comparison.
- Evaluation fees for non-core asset dispositions and other legal charges increased $1 million in the period-to-period comparison due to various corporate initiatives that were completed in 2011.
- Other corporate items increased $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Income Taxes:

The effective income tax rate was 63.4% in the three months ended September 30, 2012 compared to 16.5% in the three months ended September 30, 2011. The increase in the effective tax rate for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011 was attributable to discrete items reflected in the current year related to the accrual to return adjustment, offset in part, by the Canadian Revenue Agency adjustments. The effective tax rate was also impacted by the relationship between the pre-tax earnings and percentage depletion. 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 September 30,			
	2012	2011	Variance	Percent Change
Total Company Earnings Before Income Tax	$(31)	$200	$(231)	(115.5)%
Income Tax Expense	$(20)	$33	$(53)	(160.6)%
Effective Income Tax Rate	63.4%	16.5%	46.9%	

Results of Operations

Nine Months Ended September 30, 2012 Compared with Nine Months Ended September 30, 2011

Net Income Attributable to CONSOL Energy Shareholders

CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $239 million, or $1.04 per diluted share, for the nine months ended September 30, 2012. Net income attributable to CONSOL Energy shareholders was $437 million, or $1.91 per diluted share, for the nine months ended September 30, 2011.

The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $419 million of earnings before income tax for the nine months ended September 30, 2012 compared to $719 million for the nine months ended September 30, 2011. The total coal division sold 41.7 million tons of coal produced from CONSOL Energy mines for the nine months ended September 30, 2012 compared to 47.2 million tons for the nine months ended September 30, 2011.

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

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per ton sold	$ 67.35	$ 72.48	$ (5.13)	(7.1)%
Average Cost of Goods Sold per ton	54.09	50.07	4.02	8.0 %
Margin per ton sold	$ 13.26	$ 22.41	$ (9.15)	(40.8)%

The lower average sales price per ton sold reflects a decrease in the global metallurgical coal markets, slightly offset by higher thermal coal average prices as a result of several successful re-negotiations of domestic thermal contracts where pricing took effect on January 1, 2012. The coal division priced 8.8 million tons on the export market at an average sales price of $76.24 for the nine months ended September 30, 2012 compared to 8.6 million tons at an average price of $124.54 per ton for the nine months ended September 30, 2011. All other tons were sold on the domestic market. The decreased sales tonnage is due to decreased coal demand in both thermal and metallurgical markets and curtailed shipments due to the Bailey Belt incident discussed previously.

Changes in the average cost of goods sold per ton were primarily related to the following items:

- Average cost of goods sold 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 $1.32 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 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 retirement and disability 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 $25 million of earnings before income tax for the nine months ended September 30, 2012 compared to $53 million for the nine months ended September 30, 2011. Total gas production was 114.5 billion cubic feet for the nine months ended September 30, 2012 compared to 113.8 billion cubic feet for the nine months ended September 30, 2011. Total gas production increased primarily as a result of the on-going drilling program, offset, in part, by a 10.7 billion cubic feet decrease in production related to both the 2011 divestiture of Antero Resources Appalachian Corp. (Antero) and the 2011 Noble Joint Venture. Production also decreased due to the Buchanan Mine idling as previously discussed.

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

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	4.14	4.97	(0.83)	(16.7)%
Average Costs per thousand cubic feet sold	3.37	3.55	(0.18)	(5.1)%
Margin per thousand cubic feet sold	0.77	1.42	(0.65)	(45.8)%

Total gas division outside sales revenues were $475 million for the nine months ended September 30, 2012 compared to $566 million for the nine months ended September 30, 2011. The decrease was primarily due to the 16.7% reduction in average price per thousand cubic feet sold, offset, in part, by the 0.6% increase in volumes sold. The decrease in average sales price is the result of of the decline in general market prices, partially offset by various gas swap transactions that occurred throughout both periods. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 57.5 billion cubic feet of our produced gas sales volumes for the nine months ended September 30, 2012 at an average price of $5.25 per thousand cubic feet. These financial hedges represented 60.1 billion cubic feet of our produced gas sales volumes for the nine months ended September 30, 2011 at an average price of $5.23 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 10.7 billion cubic feet divested in the 2011 Noble and 2011 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 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 direct administrative, selling and other costs per thousand cubic feet sold due to increased sales volumes and decreased actual dollars as a result of lower direct administrative labor and other costs.
- Gathering costs increased in the period-to-period comparison due to higher 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 nine months ended September 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 Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Employee wages and related expenses	$45	$50	$(5)	(10.0)%
Consulting and professional services	24	27	(3)	(11.1)%

Contributions	2	6	(4)	(66.7)%
Miscellaneous	25	27	(2)	(7.4)%
Total Company General and Administrative Expenses	$96	$110	$(14)	(12.7)%

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

- Employee wages and related expenses decreased $5 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.
- 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.
- Contributions decreased $4 million in the period-to-period comparison due to various transactions, none of which were individually material.
- Miscellaneous general and administrative expenses decreased $2 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 $195 million for the nine months ended September 30, 2012 compared to $249 million for the nine months ended September 30, 2011. The decrease of $54 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 nine months ended September 30, 2012 compared to the nine months ended September 30, 2011:

The coal segment contributed $419 million of earnings before income tax in the nine months ended September 30, 2012 compared to $719 million in the nine months ended September 30, 2011. Variances by the individual coal segments are discussed below.

	For the Nine Months Ended September 30, 2012					Difference to Nine Months Ended September 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	$2,228	$180	$403	$6	$2,817	$(87)	$(99)	$(421)	$(16)	$(623)
Purchased Coal	—	—	—	13	13	—	—	—	(24)	(24)
Total Outside Sales	2,228	180	403	19	2,830	(87)	(99)	(421)	(40)	(647)
Freight Revenue	—	—	—	126	126	—	—	—	(30)	(30)
Other Income	1	7	—	225	233	(4)	(2)	—	172	166
Total Revenue and Other Income	2,229	187	403	370	3,189	(91)	(101)	(421)	102	(511)
Costs and Expenses:										
Beginning inventory costs	89	2	16	—	107	(9)	2	6	(1)	(2)
Total direct costs	1,160	84	160	138	1,542	28	(18)	(5)	22	27
Total royalty/production taxes	152	9	25	2	188	(3)	(2)	(25)	(2)	(32)
Total direct services to operations	185	19	17	210	431	(10)	(4)	1	5	(8)
Total retirement and disability	133	9	23	15	180	(41)	(6)	(8)	3	(52)
Depreciation, depletion and amortization	225	19	30	23	297	(1)	(3)	3	(103)	(104)
Ending inventory costs	(67)	—	(33)	(1)	(101)	15	—	(24)	(1)	(10)
Total Costs and Expenses	1,877	142	238	387	2,644	(21)	(31)	(52)	(77)	(181)
Freight Expense	—	—	—	126	126	—	—	—	(30)	(30)
Total Costs	1,877	142	238	513	2,770	(21)	(31)	(52)	(107)	(211)
Earnings (Loss) Before Income Taxes	$352	$45	$165	$(143)	$419	$(70)	$(70)	$(369)	$209	$(300)

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THERMAL COAL SEGMENT

The thermal coal segment contributed $352 million to total Company earnings before income tax for the nine months ended September 30, 2012 compared to $422 million for the nine months ended September 30, 2011. The thermal coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Company Produced Thermal Tons Sold (in millions)	36.1	39.3	(3.2)	(8.1)%
Average Sales Price Per Thermal Ton Sold	$61.79	$58.88	$2.91	4.9 %
Beginning Inventory Costs Per Thermal Ton	$58.32	$51.73	$6.59	12.7 %
Total Direct Operating Costs Per Thermal Ton Produced	$32.39	$28.98	$3.41	11.8 %
Total Royalty/Production Taxes Per Thermal Ton Produced	4.25	3.98	0.27	6.8 %
Total Direct Services to Operations Per Thermal Ton Produced	5.18	5.00	0.18	3.6 %
Total Retirement and Disability Per Thermal Ton Produced	3.71	4.46	(0.75)	(16.8)%
Total Depreciation, Depletion and Amortization Costs Per Thermal Ton Produced	6.28	5.80	0.48	8.3 %
Total Production Costs Per Thermal Ton Produced	$51.81	$48.22	$3.59	7.4 %
Ending Inventory Costs Per Thermal Ton	$51.55	$52.89	$(1.34)	(2.5)%
Total Costs Per Thermal Ton Sold	$52.06	$48.28	$3.78	7.8 %
Average Margin Per Thermal Ton Sold	$9.73	$10.60	$(0.87)	(8.2)%

Thermal coal revenue was $2,228 million for the nine months ended September 30, 2012 compared to $2,315 million for the nine months ended September 30, 2011. The $87 million decrease was attributable to a 3.2 million reduction in tons sold, offset, in part, by a $2.91 per ton higher average sales prices. The sales ton decrease was primarily due to weak market conditions and the July 27, 2012 structural failure of the above-ground conveyor system at the Bailey Preparation Plant. The incident curtailed shipments of production from both Bailey Mine and the Enlow Fork Mine during the reconstruction period, as previously discussed. 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. Higher average thermal coal sale prices per ton were offset, in part, as a result of the change in mix of coal sold as a result of the Bailey Belt incident, as previously discussed. Also, 4.1 million tons of thermal coal were priced on the export market at an average sales price of $58.10 per ton for the nine months ended September 30, 2012 compared to 1.8 million tons at an average price of $68.13 per ton for the nine months ended September 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.

Total cost of goods sold are comprised of changes in thermal coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for thermal coal was $1,877 million for the nine months ended September 30, 2012, or $21 million lower than the $1,898 million for the nine months ended September 30, 2011. Although total cost of goods sold dollars were improved, total costs per ton sold were impaired. Total cost of goods sold for thermal coal was $52.06 per ton in the nine months ended September 30, 2012 compared to $48.28 per ton in the nine months ended September 30, 2011. Average cost of goods sold per ton was impacted by the idling of the Blacksville Mine longwall during March and April 2012. The mine continued to run the continuous miners and complete mine maintenance throughout March and April which negatively impacted year-to-date unit costs by $0.79. The increase in costs of goods sold per thermal ton was due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power 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. Direct Operating costs related to the thermal coal segment were $1,160 million in the nine months ended September 30, 2012 compared to $1,132 million in the nine months ended September 30, 2011. Direct operating costs were

$32.39 per ton produced in the current period compared to $28.98 per ton produced in the prior year period. Changes in the average direct operating costs per thermal ton produced were primarily related to the following items:

- Average operating costs per thermal ton produced increased due to fewer tons produced. Fixed costs are allocated over less tons, resulting in higher unit costs.
- The Blacksville No. 2 longwall idling resulted in higher direct operating costs per ton produced. The mine continued to run the continuous miners and perform mine maintenance during the month of April when the longwall was idled for market reasons, which negatively impacted unit costs.
- Labor and related benefits average costs per thermal ton produced increased. This was primarily due to the impact of the wage increases 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.
- Average operating supplies and maintenance costs per ton increased due to additional maintenance and equipment overhaul costs and additional contractor labor, combined with lower tons produced. Additional maintenance and equipment overhaul costs are related to additional equipment being service in the current year-to-date period. Additional contractor labor costs resulted from additional underground hourly contractors utilized as well as additional security contractor costs in the current year.
- There were no significant changes in various other unit costs individually or in total.

Royalties and production taxes decreased $3 million to $152 million in the current year-to-date period. Average cost per thermal ton produced increased $0.27 per ton due to lower production volumes, and higher average sales prices which is the basis for most production taxes.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The cost of these support services were $185 million in the current year-to-date period compared to $195 million in the prior year-to-date period. Direct services to the operations were $5.18 per ton in the current period compared to $5.00 per ton in the prior year-to-date period. Changes in the average direct service to operations cost per thermal ton produced were primarily related to the following items:

- Average direct service costs to operations were impaired due to lower tons produced in the period-to-period comparison.
- Permitting and compliance costs have increased due to increased stream monitoring expenses, increased compliance work related to ponds and ditches, and additional permits for water discharge pipelines.
- Selling expense decreased in the period-to-period comparison due to fewer tons being sold under contracts that require commissions.

Retirement and disability 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, coal workers' pneumoconiosis (CWP) and long-term disability. 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. The average retirement and disability costs attributable to the thermal coal segment were $133 million for the nine months ended September 30, 2012 compared to $174 million for the nine months ended September 30, 2011. The decrease in the thermal coal retirement and disability costs 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. These improvements were offset, in part, by the reduction in production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the thermal coal segment was $225 million for the nine months ended September 30, 2012 compared to $226 million for the nine months ended September 30, 2011. The decrease was primarily due to lower depletion directly related to lower production volumes. Unit costs per thermal ton produced were higher in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis.

Changes in thermal coal inventory volumes and carrying value resulted in $22 million of cost of goods sold in the nine months ended September 30, 2012 compared to $16 million in the nine months ended September 30, 2011. Thermal coal inventory was 1.3 million tons at September 30, 2012 compared to 1.6 million tons at September 30, 2011.

HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $45 million to total Company earnings before income tax for the nine months ended September 30, 2012 compared to $115 million for the nine months ended September 30, 2011. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Company Produced High Vol Met Tons Sold (in millions)	2.9	3.5	(0.6)	(17.1)%
Average Sales Price Per High Vol Met Ton Sold	$62.64	$78.75	$(16.11)	(20.5)%
Beginning Inventory Costs Per High Vol Met Ton	$63.50	$—	$63.50	—%
Total Direct Operating Costs Per High Vol Met Ton Produced	$29.30	$28.67	$0.63	2.2%
Total Royalty/Production Taxes Per High Vol Met Ton Produced	3.15	3.10	0.05	1.6%
Total Direct Services to Operations Per High Vol Met Ton Produced	6.42	6.43	(0.01)	(0.2)%
Total Retirement and Disability Per High Vol Met Ton Produced	3.15	4.28	(1.13)	(26.4)%
Total Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Produced	6.54	6.25	0.29	4.6%
Total Production Costs Per High Vol Met Ton Produced	$48.56	$48.73	$(0.17)	(0.3)%
Ending Inventory Costs Per High Vol Met Ton	$—	$—	$—	—%
Total Costs Per High Vol Met Ton Sold	$49.44	$48.73	$0.71	1.5%
Margin Per High Vol Met Ton Sold	$13.20	$30.02	$(16.82)	(56.0)%

High volatile metallurgical coal revenue was $180 million for the nine months ended September 30, 2012 compared to $279 million for the nine months ended September 30, 2011. Average sales prices for high volatile metallurgical coal decreased $16.11 per ton in a period-to-period comparison due to a weakening in global metallurgical coal demand. CONSOL Energy priced 2.5 million tons of high volatile metallurgical coal in the export market at an average sales price of $60.10 per ton for the nine months ended September 30, 2012 compared to 3.3 million tons at an average price of $78.21 per ton for the nine months ended September 30, 2011. The remaining tons sold in the period-to-period comparison were sold on the domestic market.

Total cost of goods sold are comprised of changes in high volatile metallurgical coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for high volatile metallurgical coal was $142 million for the nine months ended September 30, 2012, or $31 million lower than the $173 million for the nine months ended September 30, 2011. Total cost of goods sold for high volatile metallurgical coal was $49.44 per ton in the nine months ended September 30, 2012 compared to $48.73 per ton in the nine months ended September 30, 2011. The increase in cost of goods sold per high volatile metallurgical ton was due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power 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. Direct Operating costs related to the high volatile metallurgical coal segment were $84 million in the nine months ended September 30, 2012 compared to $102 million in the nine months ended September 30, 2011. Direct operating costs dollars are improved due to lower tons produced in the period-to-period comparison and due to cost control measures that were implemented. Although improved $18 million, the cost improvements did not completely offset the impact of reduced production on unit costs. Direct operating costs were $29.30 per ton produced in the current year-to-date period compared to $28.67 per ton produced in the prior year-to-date period. Changes in the average direct operating costs per high volatile metallurgical ton produced were primarily related to the following items:

- Average operating costs per high volatile metallurgical ton increased due to fewer tons produced. Fixed costs are allocated over less tons, resulting in higher unit costs.

- Mine maintenance and supplies per ton produced increased due to the mix of mines producing tons that were shipped as high volatile metallurgical coal. Mines with higher cost structures produced a larger portion of the high volatile metallurgical coal shipped in the current year-to-date period compared to the prior year-to-date period. This was primarily due to the Bailey belt incident previously discussed.
- Labor and related benefits average costs per high volatile metallurgical ton produced decreased due to less overtime worked, offset, in part, by lower tons produced and higher hourly wage rates.
- Various other unit costs including power and miscellaneous costs did not change significantly individually or in total.

Royalties and production taxes improved $2 million to $9 million in the current year-to-date period compared to $11 million in the prior year-to-date period. The improvement was due to lower volumes and lower average sales prices. Although dollars were lower, unit costs were $0.05 per ton higher. High volatile metallurgical coal royalties and production taxes were $3.15 per ton in the current year-to-date period compared to $3.10 per ton in the prior year-to-date period. Average cost per high volatile metallurgical ton produced increased due to an increase in the tons mined on leased versus owned properties in the year-to-date period-to-period comparison.
Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The costs of these support services for high volatile metallurgical coal were $19 million in the current year-to-date period compared to $23 million in the prior year-to-date period. Lower costs were attributable to fewer tons subject to commission expense, lower direct administrative costs, and lower subsidence costs. Direct services to the operations for high volatile metallurgical coal were $6.42 per ton in the current year-to-date period compared to $6.43 per ton in the prior year-to-date period. Changes in the average direct service to operations cost per ton for high volatile metallurgical coal produced were primarily related to lower dollars spent, offset by lower tons produced.
Retirement and disability 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, coal workers' pneumoconiosis (CWP) and long-term disability. 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. The average retirement and disability costs attributable to the high volatile metallurgical coal segment were $9 million for the nine months ended September 30, 2012 compared to $15 million for the nine months ended September 30, 2011. The decrease in the high volatile metallurgical coal retirement and disability costs 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. These improvements were offset, in part, by the reduction in production volumes which negatively impacted unit costs.
Depreciation, depletion and amortization for the high volatile metallurgical coal segment was $19 million for the nine months ended September 30, 2012 compared to $22 million for the nine months ended September 30, 2011. The decrease was primarily due to lower depletion directly related to lower production volumes. Unit costs per high volatile ton produced were higher in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis.
Changes in high volatile metallurgical coal inventory volumes and carrying value resulted in $2 million of cost of goods sold in the nine months ended September 30, 2012. There were no changes in volumes or carrying value in the nine months ended September 30, 2011. There was no high volatile metallurgical coal inventory at September 30, 2012 or September 30, 2011.

LOW VOL METALLURGICAL COAL SEGMENT

The low volatile metallurgical coal segment contributed $165 million to total Company earnings before income tax in the nine months ended September 30, 2012 compared to $534 million in the nine months ended September 30, 2011. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Company Produced Low Vol Met Tons Sold (in millions)	2.8	4.3	(1.5)	(34.9)%
Average Sales Price Per Low Vol Met Ton Sold	$143.30	$191.84	$(48.54)	(25.3)%
Beginning Inventory Costs Per Low Vol Met Ton	$67.60	$62.51	$5.09	8.1%
Total Direct Operating Costs Per Low Vol Met Ton Produced	$54.12	$38.67	$15.45	40.0%
Total Royalty/Production Taxes Per Low Vol Met Ton Produced	8.66	11.71	(3.05)	(26.0)%
Total Direct Services to Operations Per Low Vol Met Ton Produced	5.64	3.83	1.81	47.3%
Total Retirement and Disability Per Low Vol Met Ton Produced	7.90	7.24	0.66	9.1%
Total Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Produced	10.10	6.37	3.73	58.6%
Total Production Costs Per Low Vol Met Ton Produced	$86.42	$67.82	$18.60	27.4%
Ending Inventory Costs Per Low Vol Met Ton	$87.32	$67.35	$19.97	29.7%
Total Costs Per Low Vol Met Ton Sold	$84.75	$67.62	$17.13	25.3%
Margin Per Low Vol Met Ton Sold	$58.55	$124.22	$(65.67)	(52.9)%

Low volatile metallurgical coal revenue was $403 million for the nine months ended September 30, 2012 compared to $824 million for the nine months ended September 30, 2011. The $421 million decrease was attributable to a $48.54 per ton lower average sales price. Average sales prices for low volatile metallurgical coal decreased in the period-to-period comparison due to the weakening in global metallurgical coal demand. For the 2012 period, 2.1 million tons of low volatile metallurgical coal was priced on the export market at an average price of $130.56 per ton compared to 3.5 million tons at an average price of $196.79 per ton for the 2011 period. The remaining tons sold in the period-to-period comparison were sold on the domestic market.

Total cost of goods sold are comprised of changes in low volatile metallurgical coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for low volatile metallurgical coal was $238 million for the nine months ended September 30, 2012, or $52 million lower than the $290 million for the nine months ended September 30, 2011. Total cost of goods sold for low volatile metallurgical coal was $84.75 per ton in the nine months ended September 30, 2012 compared to $67.62 per ton in the nine months ended September 30, 2011. The increase in cost of goods sold per low volatile metallurgical ton was due to the following items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power 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. Direct Operating costs related to the low volatile metallurgical coal segment were $160 million in the nine months ended September 30, 2012 compared to $165 million in the nine months ended September 30, 2011. Direct operating costs dollars are improved due to lower tons produced in the period-to-period comparison and cost control measures implemented. Although improved $5 million, the cost improvements did not offset the impact of reduced production on unit costs. Direct operating costs were $54.12 per ton produced in the current year-to-date period compared to $38.67 per ton produced in the prior year-to-date period. Changes in the average direct operating costs per low volatile ton produced were primarily related to the following items:

- The Buchanan longwall was idled during the months of March and April which resulted in $10.59 per ton higher direct operating costs produced. The mine continued to run the continuous miners and perform mine maintenance during the month when the longwall was idled. This negatively impacted unit costs.

- Low volatile metallurgical coal production was 3.0 million tons in the nine months ended September 30, 2012 compared to 4.3 million tons in the nine months ended September 30, 2011. Production was significantly lower in the period-to-period comparison due to the Buchanan Mine being idled in early September 2012. The mine was idled in response to weak market demand for low volatile metallurgical coal. Fixed costs were then spread over fewer tons produced which increased all costs on a per unit basis.

Royalties and production taxes improved $25 million to $25 million in the current year-to-date period compared to $50 million in the prior year-to-date period. Unit costs also improved $3.05 per low volatile metallurgical ton produced to $8.66 per ton in the current year-to-date period compared to $11.71 per ton in the prior year-to-date period. Average cost per low volatile metallurgical ton produced decreased due to lower royalties and lower production taxes. These decreases were related to lower volumes produced and lower average sales prices.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The costs of these support services for low volatile metallurgical coal were $17 million in the current year-to-date period compared to $16 million in the prior year-to-date period. Direct services to the operations for low volatile metallurgical coal were $5.64 per ton in the current year-to-date period compared to $3.83 per ton in the prior year-to-date period. Changes in the average direct service to operations cost per ton for low volatile metallurgical coal produced were primarily related to lower tons of coal produced in the period-to-period comparison.

Retirement and disability 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, coal workers' pneumoconiosis (CWP) and long-term disability. 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. The average retirement and disability costs attributable to the low volatile metallurgical coal segment were $23 million for the nine months ended September 30, 2012 compared to $31 million for the nine months ended September 30, 2011. The decrease in the low volatile metallurgical coal retirement and disability costs 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 production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the low volatile metallurgical coal segment was $30 million for the nine months ended September 30, 2012 compared to $27 million for the nine months ended September 30, 2011. Unit costs per low volatile metallurgical ton produced were higher in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis. These costs were offset by lower depletion charges related to lower volumes produced.

Changes in low volatile metallurgical coal inventory volumes and carrying value resulted in a decrease of $17 million to cost of goods sold in the nine months ended September 30, 2012 and an increase of $1 million to cost of goods sold in the nine months ended September 30, 2011. Produced low volatile metallurgical coal inventory was 0.4 million tons at September 30, 2012 compared to 0.2 million tons at September 30, 2011.

OTHER COAL SEGMENT

The other coal segment had a loss before income tax of $143 million for the nine months ended September 30, 2012 compared to a loss before income tax of $352 million for the nine months ended September 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 nine months ended September 30, 2012 and 0.3 million tons for the nine months ended September 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 and coal purchased from third parties and sold directly to our customers. The revenues were $13 million for the nine months ended September 30, 2012 compared to $37 million for the nine months ended September

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 $126 million for the nine months ended September 30, 2011 compared to $156 million for the nine months ended September 30, 2011. The $30 million decrease in freight revenue was due to decreased shipments under contracts which CONSOL Energy contractually provides transportation services.

Miscellaneous other income was $225 million for the nine months ended September 30, 2012 compared to $53 million for the nine months ended September 30, 2011. The $172 million increase is due to the following items:

- Gain on sale of assets attributable to the Other Coal segment were $181 million in the nine months ended September 30, 2012 compared to $5 million in the nine months ended September 30, 2011. The change was 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. The remaining change was related to various transactions that occurred throughout both periods, none of which were individually material.
- In the nine months ended September 30, 2012, $12 million of income was recognized related to contracts from certain thermal coal customers that were unable to take delivery of previously contracted coal tonnage. These customers agreed to buy out their contracts in order to be released from the requirements of taking delivery of previously committed tons. No such transactions were entered into in the year ended September 30, 2011.
- In the nine months ended September 30, 2011, a gain of $10 million was recognized for the issuance of a pipeline right-of-way to a third party. There were no such transactions in the nine months ended September 30, 2012.
- Equity in earnings of affiliates decreased $6 million due to lower earnings from our equity affiliates.

Other coal segment total costs were $513 million for the nine months ended September 30, 2012 compared to $620 million for the nine months ended September 30, 2011. The decrease of $107 million was due to the following items:

	For the nine months ended September 30,		
	2012	2011	Variance
Abandonment of long-lived assets	$—	$116	$(116)
Freight expense	126	156	(30)
Purchased Coal	32	57	(25)
PA Streams	—	5	(5)
Coal contract buyout	—	5	(5)
Closed and idle mines	112	80	32
Bailey Belt Incident	42	—	42
Other	201	201	—
Total Other Coal Segment Costs	$513	$620	$(107)

- Abandonment of long-lived assets were $116 million for the nine months ended September 30, 2011 as a result of the 2011 decision to permanently idle Mine 84.
- 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. The decrease in freight expense was due to decreased shipments under contracts which CONSOL Energy contractually provides transportation services.
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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.

- PA Streams costs were $5 million for the nine months ended September 30, 2011 as a result of the recognition of an additional liability related to the environmental remediation of streams in Pennsylvania affected by our mines.
- 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.

- Closed and idle mine costs increased approximately $32 million for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. The increase was the result of $36 million additional costs related to reclamation liabilities and on-going idling costs incurred at the Fola Complex in the nine months ended September 30, 2012. Closed and idle mine costs increased $8 million as the result of a 2012 decision to temporarily idle Buchanan Mine in 2012. Closed and idle mine costs increased $4 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. Closed and idle mine costs decreased $16 million as the result of a 2011 decision to permanently abandon Mine 84 in 2011.
- Bailey Belt Incident costs represents expenses during the belt-reconstruction period related to continued advancement of the mines and on-going projects at the mines
- Other expenses related to the coal segment remained consistent for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011.

TOTAL GAS SEGMENT ANALYSIS for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011:

The gas segment contributed $25 million to earnings before income tax in the nine months ended September 30, 2012 compared to $53 million in the nine months ended September 30, 2011.

	For the Nine Months Ended September 30, 2012					Difference to Nine Months Ended September 30, 2011				
	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$281	$101	$84	$7	$473	$(64)	$(19)	$(4)	$(2)	$(89)
Related Party	2	—	—	—	2	(2)	—	—	—	(2)
Total Outside Sales	283	101	84	7	475	(66)	(19)	(4)	(2)	(91)
Gas Royalty Interest	—	—	—	35	35	—	—	—	(17)	(17)
Purchased Gas	—	—	—	2	2	—	—	—	(1)	(1)
Other Income	—	—	—	46	46	—	—	—	55	55
Total Revenue and Other Income	283	101	84	90	558	(66)	(19)	(4)	35	(54)
Lifting	28	31	9	1	69	(1)	(3)	(2)	—	(6)
Ad Valorem, Severance, and Other Taxes	7	7	3	2	19	(2)	(2)	2	1	(1)
Gathering	78	18	17	—	113	6	(2)	7	(1)	10
Gas Direct Administrative, Selling & Other	12	11	10	3	36	(12)	(6)	1	6	(11)
Depreciation, Depletion and Amortization	66	44	31	7	148	(9)	(4)	2	—	(11)
General & Administration	—	—	—	29	29	—	—	—	(6)	(6)
Gas Royalty Interest	—	—	—	28	28	—	—	—	(19)	(19)
Purchased Gas	—	—	—	2	2	—	—	—	(1)	(1)
Exploration and Other Costs	—	—	—	29	29	—	—	—	19	19
Other Corporate Expenses	—	—	—	56	56	—	—	—	7	7
Interest Expense	—	—	—	4	4	—	—	—	(3)	(3)
Total Cost	191	111	70	161	533	(18)	(17)	10	3	(22)
Earnings Before Noncontrolling Interest and Income Tax	92	(10)	14	(71)	25	(48)	(2)	(14)	32	(32)
Noncontrolling Interest	—	—	—	—	—	—	—	—	(4)	(4)
Earnings Before Income Tax	$92	$(10)	$14	$(71)	$25	$(48)	$(2)	$(14)	$36	$(28)

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $92 million to the total Company earnings before income tax for the nine months ended September 30, 2012 compared to $140 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas CBM sales volumes (in billion cubic feet)	66.8	68.6	(1.8)	(2.6)%
Average CBM sales price per thousand cubic feet sold	$4.24	$5.09	$(0.85)	(16.7)%
Average CBM lifting costs per thousand cubic feet sold	0.42	0.42	—	—%
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	1.04	0.13	12.5%
Average CBM direct administrative, selling & other costs per thousand cubic feet sold	0.18	0.34	(0.16)	(47.1)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	0.99	1.10	(0.11)	(10.0)%
Total Average CBM costs per thousand cubic feet sold	2.87	3.04	(0.17)	(5.6)%
Average Margin for CBM	$1.37	$2.05	$(0.68)	(33.2)%

CBM sales revenues were $283 million in the nine months ended September 30, 2012 compared to $349 million for the nine months ended September 30, 2011. The $66 million decrease was primarily due to a 16.7% decrease in average sales price per thousand cubic feet sold and a 2.6% decrease in average volumes sold. The decrease in CBM average sales price was the result of lower average market prices and various gas swap transactions that matured 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 34.5 billion cubic feet of our produced CBM gas sales volumes for the nine months ended September 30, 2012 at an average price of $5.34 per thousand cubic feet. For the nine months ended September 30, 2011, these financial hedges represented 45.1 billion cubic feet at an average price of $5.37 per thousand cubic feet. CBM sales volumes decreased 1.8 billion cubic feet for the nine months ended September 30, 2012 compared to the 2011 year-to-date period primarily due to normal well declines without a corresponding increase in wells drilled and the Buchanan Mine idling, as previously discussed. Currently, the focus of the gas division is to develop its Marcellus and Utica acreage. At September 30, 2012, there were 4,493 gross CBM wells in production. At September 30, 2011, there were 4,397 gross CBM wells in production.

Total costs for the CBM segment were $191 million for the nine months ended September 30, 2012 compared to $209 million for the nine months ended September 30, 2011. Lower costs in the period-to-period comparison are primarily related to lower unit costs, coupled with decreased gas production as discussed above.

CBM lifting costs were $28 million for the nine months ended September 30, 2012 compared to $29 million for the nine months ended September 30, 2011. The $1 million decrease is primarily due to idle rig costs incurred during the 2011 period. The reduced costs were offset by lower sales volumes resulting in average unit costs of $0.42 in both periods.

CBM ad valorem, severance and other taxes were $7 million for the nine months ended September 30, 2012 compared to $9 million for the nine months ended September 30, 2011. Reduced severance tax expense was the result of lower average gas sales prices during 2012. Decreased costs, offset, in part, by lower sales volumes sold resulted in $0.03 decrease to average unit costs.

CBM gathering costs were $78 million for the nine months ended September 30, 2012 compared to $72 million for the nine months ended September 30, 2011. Higher average CBM gathering unit costs are related to increased power usage, higher compressor maintenance, higher equipment lease expenses and lower volumes sold in the period-to-period comparison.

CBM direct administrative, selling & other costs for the CBM segment were $12 million for the nine months ended September 30, 2012 compared to $24 million for the nine months ended September 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 CBM volumes representing a smaller proportion of total natural gas volumes.

Depreciation, depletion and amortization attributable to the CBM segment was $66 million for the nine months ended September 30, 2012 compared to $75 million for the nine months ended September 30, 2011. There was approximately $45 million, or $0.68 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 nine months ended September 30, 2012. The production portion of depreciation, depletion and amortization was $53 million, or $0.78 per unit-of-production in the nine months ended September 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 $21 million, or $0.31 average per unit cost of depreciation, depletion and amortization relating to gathering and other equipment reflected on a straight line basis for the nine months ended September 30, 2012. The non-production related depreciation, depletion and amortization was $22 million, or $0.32 per thousand cubic feet for the nine months ended September 30, 2011.

SHALLOW OIL AND GAS SEGMENT

The Shallow Oil and Gas segment had a loss before income tax of $10 million for the nine months ended September 30, 2012 compared to a loss before income tax of $8 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas Shallow Oil and Gas sales volumes (in billion cubic feet)	21.8	24.0	(2.2)	(9.2)%
Average Shallow Oil and Gas sales price per thousand cubic feet sold	$4.62	$5.00	$(0.38)	(7.6)%
Average Shallow Oil and Gas lifting costs per thousand cubic feet sold	1.40	1.44	(0.04)	(2.8)%
Average Shallow Oil and Gas ad valorem, severance, and other taxes per thousand cubic feet sold	0.34	0.38	(0.04)	(10.5)%
Average Shallow Oil and Gas gathering costs per thousand cubic feet sold	0.81	0.84	(0.03)	(3.6)%
Average Shallow Oil and Gas direct administrative, selling & other costs per thousand cubic feet sold	0.49	0.71	(0.22)	(31.0)%
Average Shallow Oil and Gas depreciation, depletion and amortization costs per thousand cubic feet sold	2.01	1.98	0.03	1.5%
Total Average Shallow Oil and Gas costs per thousand cubic feet sold	5.05	5.35	(0.30)	(5.6)%
Average Margin for Shallow Oil and Gas	$(0.43)	$(0.35)	$(0.08)	22.9%

Shallow Oil and Gas sales revenues were $101 million for the nine months ended September 30, 2012 compared to $120 million for the nine months ended September 30, 2011. The $19 million decrease was primarily due to the 9.2% decrease in volumes sold as well as the 7.6% decrease in average sales price. The decrease in shallow oil and gas average sales price is the result of lower average market prices and 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 14.3 billion cubic feet of our produced shallow oil and gas sales volumes for the nine months ended September 30, 2012 at an average price of $5.23 per thousand cubic feet. For the nine months ended September 30, 2011, these financial hedges represented 8.0 billion cubic feet at an average price of $4.97 per thousand cubic feet. At September 30, 2012, there were 9,936 gross Shallow Oil and Gas wells in production. At September 30, 2011, there were 10,015 gross Shallow Oil and Gas wells in production.

Total costs for the shallow oil and gas segment were $111 million for the nine months ended September 30, 2012 compared to $128 million for the nine months ended September 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 $31 million for the nine months ended September 30, 2012 compared to $34 million for the nine months ended September 30, 2011. The $3 million decrease to total costs and $0.04 decrease to average unit costs is due to lower road maintenance and lower contract services in the current period, offset, in part by lower volumes sold.

Shallow Oil and Gas ad valorem, severance and other taxes were $7 million for the nine months ended September 30, 2012 compared to $9 million for the nine months ended September 30, 2011. The decrease to total costs and average unit costs was primarily due to reduced severance tax expense caused by lower average gas sales prices during the current year-to-date period.

Shallow Oil and Gas gathering costs were $18 million for the nine months ended September 30, 2012 compared to $20 million for the nine months ended September 30, 2011. Gathering costs decreased primarily due to lower compressor maintenance and lower equipment lease expenses in the period-to-period comparison The impact of these reductions on unit costs were offset, in part, by lower sales volumes.

Shallow Oil and Gas direct administrative, selling & other costs were $11 million for the nine months ended September 30, 2012 compared to $17 million for the nine months ended September 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 $6 million decrease in the period-to-period comparison is due to reduced direct administrative labor and Shallow Oil and Gas volumes representing a smaller proportion of total natural gas volumes.

Depreciation, depletion and amortization costs were $44 million for the nine months ended September 30, 2012 compared to $48 million for the nine months ended September 30, 2011. There was approximately $38 million, or $1.75 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 nine months ended September 30, 2012. There was approximately $43 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 nine months ended September 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 $6 million, or $0.26 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 nine months ended September 30, 2012. There was $5 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 nine months ended September 30, 2011.

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $14 million to the total Company earnings before income tax for the nine months ended September 30, 2012 compared to $28 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,				
	2012	2011	Variance	Percent Change	
Produced Gas Marcellus sales volumes (in billion cubic feet)	24.0	19.7	4.3	21.8	%
Average Marcellus sales price per thousand cubic feet sold	$3.48	$4.48	$(1.00)	(22.3)	%
Average Marcellus lifting costs per thousand cubic feet sold	0.39	0.57	(0.18)	(31.6)	%
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	0.49	0.15	30.6	%
Average Marcellus direct administrative, selling & other costs per thousand cubic feet sold	0.43	0.43	—	—	%

Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	1.30	1.50	(0.20)	(13.3)%
Total Average Marcellus costs per thousand cubic feet sold	2.89	3.04	(0.15)	(4.9)%
Average Margin for Marcellus	$0.59	$1.44	$(0.85)	(59.0)%

The Marcellus segment sales revenues were $84 million for the nine months ended September 30, 2012 compared to $88 million for the nine months ended September 30, 2011. The $4 million decrease is primarily due to a 22.3% decrease to average sales prices, partially offset by a 21.8% increase in volumes sold in the period-to-period comparison. The decrease in Marcellus average sales price was the result of the decline in general market prices and by various gas swap transactions that matured in the nine months ended September 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 8.5 billion cubic feet of our produced Marcellus gas sales volumes for the nine months ended September 30, 2012 at an average price of $4.97 per thousand cubic feet. For the nine months ended September 30, 2011, these financial hedges represented 6.8 billion cubic feet at an average price of $4.60 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 10.7 billion cubic feet decrease in sales volumes related to the 2011 Antero divestiture and 2011 Noble joint venture. At September 30, 2012, there were 194 gross Marcellus Shale wells in production. At September 30, 2011, there were 122 gross Marcellus Shale wells in production

Marcellus lifting costs were $9 million for the nine months ended September 30, 2012 compared to $11 million for the nine months ended September 30, 2011. The decrease to average unit costs is due to lower well servicing costs, well tending costs and additional sales volumes during the 2012 year-to-date period.

Marcellus ad valorem, severance and other taxes were $3 million for the nine months ended September 30, 2012 compared to $1 million for the nine months ended September 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 $17 million for the nine months ended September 30, 2012 compared to $10 million for the nine months ended September 30, 2011. The increase to average unit costs is due to higher firm transportation costs and the 4.3 billion cubic feet of additional volumes sold.

Marcellus direct administrative, selling & other costs were $10 million for the nine months ended September 30, 2012 compared to $9 million for the nine months ended September 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 increase in direct administrative, selling & other costs was primarily due to an increase in direct administrative labor. The impact on average unit costs from the increase in direct administrative labor was offset by higher volumes sold.

Depreciation, depletion and amortization costs were $31 million for the nine months ended September 30, 2012 compared to $29 million for the nine months ended September 30, 2011. There was approximately $28 million, or $1.20 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 nine months ended September 30, 2012. There was approximately $22 million, or $1.10 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 nine months ended September 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 $3 million, or $0.10 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 nine months ended September 30, 2012. There was $7 million, or $0.40 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the nine months ended September 30, 2011. The decrease in Marcellus gathering and other equipment depreciation, depletion and amortization relates to the sale of assets to CONE Gathering LLC (CONE), a 50% owned affiliate. CONE was created as part of the Noble transaction during 2011. See Note 2 - Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional information.

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 and the Utica Shale in Ohio. Revenue from these operations were approximately $7 million for the nine months ended September 30, 2012 and $9 million for the nine months ended September 30, 2011. Total costs related to these other sales were $13 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 increased direct administrative, selling & other costs. Increased direct administrative, selling and other costs is primarily related to higher proportional allocation relating to the Utica operating area during 2012. A per unit analysis of the other operating costs in Chattanooga Shale and Utica 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 $35 million for the nine months ended September 30, 2012 compared to $52 million for the nine months ended September 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 Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	13.2	12.2	1.0	8.2 %
Average Sales Price Per thousand cubic feet	$ 2.63	$ 4.27	$ (1.64)	(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 $2 million for the nine months ended September 30, 2012 and $3 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	0.8	0.7	0.1	14.3 %
Average Sales Price Per thousand cubic feet	$ 2.90	$ 4.50	$ (1.60)	(35.6)%

Other income was $46 million for the nine months ended September 30, 2012 compared to a loss of $9 million for the nine months ended September 30, 2011. The $55 million increase was primarily due to $24 million of additional interest income relating to the notes receivable from the Noble joint venture transaction, $10 million of additional gains on dispositions of non-core acreage and equipment, and a $4 million increase relating to earnings from equity affiliates. Additionally, CONSOL incurred a $58 million loss on the Noble transaction during 2011, partially offset by a gain on the sale to Antero of an overriding royalty interest of $41 million during 2011.

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 $29 million for the nine months ended September 30, 2012 compared to $35 million for the nine months ended September 30, 2011. Refer to the discussion of total company general and administrative costs contained in the section "Net Income Attributable to CONSOL Energy Shareholders" of this quarterly report for a detail cost explanation.

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 $28 million for the nine months ended September 30, 2012 compared to $47 million for the nine months ended September 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 Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	13.2	12.2	1.0	8.2 %
Average Cost Per thousand cubic feet sold	$ 2.12	$ 3.81	$ (1.69)	(44.4)%

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 $2 million for the nine months ended September 30, 2012 compared to $3 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	1.0	0.9	0.1	11.1 %
Average Cost Per thousand cubic feet sold	$ 2.22	$ 3.11	$ (0.89)	(28.6)%

Exploration and other costs were $29 million for the nine months ended September 30, 2012 compared to $10 million for the nine months ended September 30, 2011. The $19 million decrease is due to the following items:

	For the Nine Months Ended September 30,				
	2012	2011	Variance	Percent Change	
Lease Expiration Costs	$19	$7	$12	171.4	%
Dry Hole Costs	7	2	5	250.0	%
Exploration	3	1	2	200.0	%
Total Exploration and Other Costs	$29	$10	$19	190.0	%

- Lease Expiration costs increased $12 million due to various lease expirations relating to locations where CONSOL Energy allowed primary lease terms to expire.
- Dry Hole Costs increased $5 million primarily due to a favorable settlement involving defective pipe in 2011 which reduced expenses in the nine months ended September 30, 2011.
- Exploration expenses increased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.

Other corporate expenses were $56 million for the nine months ended September 30, 2012 compared to $49 million for the nine months ended September 30, 2011. The $7 million increase in the period-to-period comparison was made up of the following items:

	For the Nine Months Ended September 30,				
	2012	2011	Variance	Percent Change	
PA Impact Fee	$4	$—	$4	100.0	%
Stock - based compensation	15	13	2	15.4	%
Short Term Incentive Compensation	20	19	1	5.3	%
Bank Fee	5	5	—	—	%
Unutilized Firm Transportation	9	11	(2)	(18.2)	%
Other	3	1	2	200.0	%
Total Other Corporate Expenses	$56	$49	$7	14.3	%

- PA impact fees are related to legislation in the state of Pennsylvania (Act 13 of 2012, House Bill 1950) which was signed into law during the first quarter of 2012. This legislation permits Pennsylvania counties to impose annual fees on unconventional gas wells located within their borders. As part of the legislation, all unconventional wells which were drilled prior to January 1, 2012 were assessed an initial fee related to periods prior to 2012. The $4 million represents this one-time initial assessment on wells drilled prior to January 1, 2012. On-going PA impact fees which relate to current year wells drilled are included as part of ad valorem, severance and other taxes in the Marcellus gas segment.
- Stock-based compensation was higher in the period-to-period comparison primarily due to the increased allocation from CONSOL Energy as a result of an increase in total CONSOL Energy stock-based compensation expense. Stock-based compensation costs are allocated to the gas segment based on revenue and capital expenditure projections between coal and gas.
- The short-term incentive compensation program is designed to increase compensation to eligible employees when CNX Gas reaches predetermined targets for safety, production and unit costs. Short-term incentive compensation expense was higher for the 2012 year-to-date period compared to the 2011 year-to-date period due to the projected higher payouts.
- Bank Fees remained consistent in the period-to-period comparison.
- Unutilized firm transportation costs represent pipeline transportation capacity the gas segment has obtained to enable gas production to flow uninterrupted as sales volumes increase. The $2 million decrease is due to increased utilization of pipeline capacity in the 2012 period.
- Other corporate related expense increased $2 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Interest expense related to the gas segment was $4 million for the nine months ended September 30, 2012 compared to $7 million for the nine months ended September 30, 2011. Interest was incurred by the gas segment on the CNX Gas revolving credit facility, a capital lease and debt that was held by a variable interest entity. The $3 million decrease was primarily due to lower levels of borrowings on the revolving credit facility in the period-to-period comparison.

Noncontrolling interest represents 100% of the earnings impact of a third party in which CONSOL Energy held no ownership interest. The variance in the noncontrolling amounts reflects the third parties variance in earnings in the period-to-period comparison. In the nine month's ended September 30, 2011, the drilling services contract was bought out. Subsequent to this transaction, the noncontrolling interest was de-consolidated.

OTHER SEGMENT ANALYSIS for the nine months ended September 30, 2012 compared to the nine months ended September 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 segment. The other segment had a loss before income tax of $145 million for the nine months ended September 30, 2012 compared to a loss before income tax of $222 million for the nine months ended September 30, 2011. The other segment also includes total Company income tax expense of $60 million for the nine months ended September 30, 2012 compared to $113 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Sales—Outside	$281	$252	$29	11.5 %
Other Income	17	14	3	21.4 %
Total Revenue	298	266	32	12.0 %
Cost of Goods Sold and Other Charges	250	282	(32)	(11.3)%
Depreciation, Depletion & Amortization	18	14	4	28.6 %
Taxes Other Than Income Tax	9	9	—	— %
Interest Expense	166	183	(17)	(9.3)%
Total Costs	443	488	(45)	(9.2)%
Loss Before Income Tax	(145)	(222)	77	34.7 %
Income Tax	60	113	(53)	(46.9)%
Net Loss	$(205)	$(335)	$130	(38.8)%

Industrial supplies:
Total revenue from industrial supplies was $193 million for the nine months ended September 30, 2012 compared to $172 million for the nine months ended September 30, 2011. The increase was related to higher sales volumes.
Total costs related to industrial supply sales were $186 million for the nine months ended September 30, 2012 compared to $173 million for the nine months ended September 30, 2011. The increase of $13 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 $95 million for the nine months ended September 30, 2012 compared to $88 million for the nine months ended September 30, 2011. The increase of $7 million was primarily attributable to higher per ton thru-put rates and increased tonnage thru-put at the CNX Marine Terminal.
Total costs related to the transportation operations were $65 million for the nine months ended September 30, 2012 compared to $66 million for the nine months ended September 30, 2011. The decrease was due to various items in both periods, none of which were individually material.
Miscellaneous other:
Additional other income of $10 million was recognized for the nine months ended September 30, 2012 compared to $6 million for the nine months ended September 30, 2011. The $4 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, acquisition and financing costs and various other miscellaneous corporate charges. Total other costs were $192 million for the nine months ended September 30, 2012 compared to $249 million for the nine months ended September 30, 2011. Other corporate costs decreased due to the

following items:

	For the Nine Months Ended September 30,		
	2012	2011	Variance
Interest Expense	$166	$183	$(17)
Loss on extinguishment of debt	—	16	(16)
Transaction and financing fees	—	15	(15)
Bank fees	10	16	(6)
Evaluation fees for non-core asset dispositions and other legal charges	4	5	(1)
Other	12	14	(2)
	$192	$249	$(57)

- Interest Expense decreased $17 million in the period-to-period comparison. Interest expense decreased due to an increase in capitalized interest due to higher capital expenditures for major construction projects in the current period. Capital expenditures for coal activities increased $283 million in the period-to-period comparison.
- 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.
- Transaction and financing fees of $15 million incurred in the nine months ended September 30, 2011 related to the solicitation of consents of the long-term bonds needed in order to clarify the indentures that relate to joint arrangements with respect to its oil and gas properties.
- Bank fees decreased $6 million due to lower borrowings on the revolving credit facilities in the period-to-period comparison.
- Evaluation fees for non-core asset dispositions and other legal charges decreased $1 million in the period-to-period comparison due to various corporate initiatives that began after 2010.
- Other corporate items decreased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.

Income Taxes:

The effective income tax rate was 20.2% for the nine months ended September 30, 2012 compared to 20.6% for the nine months ended September 30, 2011. The slight decrease in the effective tax rate for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011 was attributable to the relationship between pre-tax earnings and percentage depletion. Also effecting the rate was the gain on sale of CONSOL Energy's non-producing Northern Powder River Basin (PRB) assets on June 29, 2012 of $151 million and various adjustments to the accrued income taxes versus the actual income taxes filed. See Note 5—Income Taxes of the Notes to the Condensed Consolidated Financial Statements of this Form 10-Q for additional information.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Total Company Earnings Before Income Tax	$299	$550	$(251)	(45.6)%
Income Tax Expense	$60	$113	$(53)	(46.9)%
Effective Income Tax Rate	20.2%	20.6%	(0.4)%	

Liquidity and Capital Resources

CONSOL Energy generally has satisfied its working capital requirements and funded its capital expenditures and debt service obligations with cash generated from operations and proceeds from borrowings. CONSOL Energy's $1.5 billion Senior Secured Credit Agreement expires April 12, 2016. CONSOL Energy's credit facility allows for up to $1.5 billion of borrowings and letters of credit. CONSOL Energy can request an additional $250 million 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 is calculated as the ratio of EBITDA to cash interest expense of CONSOL Energy and certain of its subsidiaries. The interest coverage ratio was 5.20 to 1.00 at September 30, 2012. The facility includes a maximum leverage ratio covenant of no more than 4.75 to 1.00 through March 2013, and no more than 4.50 to 1.00 thereafter, measured quarterly. The leverage ratio is calculated as the ratio of financial covenant debt to twelve-month trailing EBITDA for CONSOL Energy and certain subsidiaries. Financial covenant debt is comprised of the outstanding indebtedness and specific letters of credit, less cash on hand, for CONSOL Energy and certain of its subsidiaries. EBITDA, as used in the covenant calculation, excludes non-cash compensation expenses, non-recurring transaction expenses, uncommon gains and losses, gains and losses on discontinued operations and includes cash distributions received from affiliates plus pro-rata earnings from material acquisitions. The leverage ratio was 2.43 to 1.00 at September 30, 2012. The facility also includes a senior secured leverage ratio covenant of no more than 2.00 to 1.00, measured quarterly. The senior secured leverage ratio is calculated as the ratio of secured debt to EBITDA. Secured debt is defined as the outstanding borrowings and letters of credit on the revolving credit facility. The senior secured leverage ratio was 0.08 to 1.00 at September 30, 2012. 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 company and amend, modify or restate, in any material way, the senior unsecured notes. At September 30, 2012, the facility had no outstanding borrowings and $100 million of letters of credit outstanding, leaving $1.4 billion of unused capacity. From time to time, CONSOL Energy is required to post financial assurances to satisfy contractual and other requirements generated in the normal course of business. Some of these assurances are posted to comply with federal, state or other government agencies statutes and regulations. We sometimes use letters of credit to satisfy these requirements and these letters of credit reduce our borrowing facility capacity.

CONSOL Energy also has an accounts receivable securitization facility. This facility allows the Company to receive, on a revolving basis, up to $200 million of short-term funding and letters of credit. The accounts receivable facility supports sales, on a continuous basis to financial institutions, of eligible trade accounts receivable. CONSOL Energy has agreed to continue servicing the sold receivables for the financial institutions for a fee based upon market rates for similar services. The cost of funds is based on commercial paper rates plus a charge for administrative services paid to financial institutions. At September 30, 2012, eligible accounts receivable totaled approximately $200 million. At September 30, 2012, the facility had no outstanding borrowings and $161 million of letters of credit outstanding, leaving $39 million of unused capacity.

CNX Gas' $1.0 billion 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 $1.0 billion for borrowings and letters of credit. CNX Gas can request an additional $250 million increase in the aggregate borrowing limit amount. Fees and interest rate spreads are based on the percentage of facility utilization, measured quarterly. The facility includes a minimum interest coverage ratio covenant of no less than 3.00 to 1.00, measured quarterly. The interest coverage ratio is calculated as the ratio of EBITDA to cash interest expense for CNX Gas and its subsidiaries. The interest coverage ratio was 42.40 to 1.00 at September 30, 2012. The facility also includes a maximum leverage ratio covenant of no more than 3.50 to 1.00, measured quarterly. The leverage ratio is calculated as the ratio of financial covenant debt to twelve-month trailing EBITDA for CNX Gas and its subsidiaries. Financial covenant debt is comprised of the outstanding indebtedness and letters of credit, less cash on hand, for CNX Gas and its subsidiaries. EBITDA, as used in the covenant calculation, excludes non-cash compensation expenses, non-recurring transaction expenses, gains and losses on the sale of assets, uncommon gains and losses, gains and losses on discontinued operations and includes cash distributions received from affiliates plus pro-rata earnings from material acquisitions. The leverage ratio was 0.00 to 1.00 at September 30, 2012. Covenants in the facility limit CNX Gas' ability to dispose of assets, make investments, pay dividends and merge with another company. The credit facility allows unlimited 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. At September 30, 2012, the facility had no amounts drawn and $70 million of letters of credit outstanding, leaving $930 million of unused capacity.

Uncertainty in the financial markets brings additional potential risks to CONSOL Energy. The risks include declines in our stock price, less availability and higher costs of additional credit, potential counterparty defaults, and commercial bank failures. Financial market disruptions may impact our collection of trade receivables. As a result, CONSOL Energy regularly monitors the creditworthiness of our customers. We believe that our current group of customers are financially sound and represent no abnormal business risk.

CONSOL Energy believes that cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major acquisitions), scheduled debt payments, anticipated dividend payments and to provide required letters of credit. Nevertheless, the ability of CONSOL Energy to satisfy its working capital requirements, to service its debt obligations, to fund planned capital expenditures or to pay dividends will depend upon future operating performance, which will be affected by prevailing economic conditions in the coal and gas industries and other financial and business factors, some of which are beyond CONSOL Energy’s control.

In order to manage the market risk exposure of volatile natural gas prices in the future, CONSOL Energy enters into various physical gas supply transactions with both gas marketers and end users for terms varying in length. CONSOL Energy has also entered into various gas swap transactions that qualify as financial cash flow hedges, which exist parallel to the underlying physical transactions. The fair value of these contracts was a net asset of $134 million at September 30, 2012. The ineffective portion of these contracts was insignificant to earnings in the three months and nine months ended September 30, 2012. No issues related to our hedge agreements have been encountered to date.

CONSOL Energy frequently evaluates potential acquisitions. CONSOL Energy has funded acquisitions with cash generated from operations and a variety of other sources, depending on the size of the transaction, including debt and equity financing. There can be no assurance that additional capital resources, including debt and equity financing, will be available to CONSOL Energy on terms which CONSOL Energy finds acceptable, or at all.

Cash Flows (in millions)

	For the Nine Months Ended September 30,		
	2012	2011	Change
Cash flows from operating activities	$530	$1,252	$(722)
Cash used in investing activities	$(587)	$(231)	$(356)
Cash used in financing activities	$(88)	$(581)	$493

Cash flows provided by operating activities changed in the period-to-period comparison primarily due to the following items:

- Operating cash flow decreased $722 million in 2012 due to lower net income in the period-to-period comparison.
- Operating cash flows decreased due to various other changes in operating assets, operating liabilities, other assets and other liabilities which occurred throughout both years, none of which were individually material.

Net cash used in investing activities changed in the period-to-period comparison primarily due to the following items:

- Total capital expenditures increased $155 million to $1,152 million in the nine months ended September 30, 2012 compared to $997 million in the nine months ended September 30, 2011. Capital expenditures for coal and other activities increased $283 million in the period-to-period comparison. The ongoing development and expenditures of the BMX mine, which is scheduled to go on-line in 2014, increased $51 million in the period-to-period comparison. Capital expenditures for the Northern West Virginia RO system increased $71 million in the period-to-period comparison. In the nine months ended September 30, 2012 capital expenditures related to long wall roof shields increased $70 million in the period-to-period comparison. The remaining $91 million increase was due to various projects throughout both periods, none of which were individually material. Capital expenditures for the gas segment decreased $128 million primarily due to a decrease in CBM drilling and gathering system expenditures in the period-to-period comparison.
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Proceeds from the sale of assets decreased $111 million in the period-to-period comparison. The decrease was due to $344 million received on September 30, 2012 related to the Noble Transaction compared to $489 million in net proceeds related to the Noble Transaction received on September 30, 2011. On September 21, 2011, CONSOL Energy sold an overriding royalty to Antero Resources Appalachian Corp. for $190 million of net proceeds. These decreases were offset, in part, by the sale of non-producing Northern Powder River Basin (PRB) assets on June 29, 2012, which resulted in proceeds of $170 million. Also, the sale of various other properties in 2012 which resulted in proceeds of $39 million. The remaining $15 million period-to-period increase was from various other transactions that occurred throughout both periods, none of which were individually material. See Note 2 -

Acquisitions and Dispositions, in the Consolidated Financial Statements included in this Form 10-Q for more information.

- Distributions From, net of (Investments In), Equity Affiliates decreased $90 million in the period-to-period comparison. During the 2012 period, $35 million was contributed to CONE in order to meet the operating and capital expenditure needs of the joint venture. The joint venture, of which CONSOL Energy owns 50%, was established on September 30, 2011 to develop and operate the gas gathering system in the Marcellus Shale play. On September 30, 2011, CONSOL Energy received a $68 million cash distribution from CONE Gathering LLC. See Note 2-Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional details. The remaining $13 million increase was primarily due to additional cash distributions received from various Equity Affiliates in the period-to-period comparison.

Net cash used in financing activities changed in the period-to-period comparison primarily due to the following items:

- In 2011, proceeds of $250 million were received in connection with the issuance of $250 million of 6.375% senior unsecured notes due in March 2021.
- In 2011, CONSOL Energy repaid $200 million of borrowings under the accounts receivable securitization facility.
- In 2011, CONSOL Energy paid outstanding borrowings of $284 million under the revolving credit facilities.
- In April 2011, CONSOL Energy paid $266 million, including a make-whole provision, to redeem the 7.875% notes that were due in March 2012.
- Dividends of $85 million were paid in 2012 compared to $68 million in 2011. This is due to the increase of the quarterly dividend by 25%, or $0.025 per share, to $0.125 per share in the 2012 period.

The following is a summary of our significant contractual obligations at September 30, 2012 (in thousands):

	Payments due by Year				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Purchase Order Firm Commitments	$354,358	$13,688	$—	$—	$368,046
Gas Firm Transportation	79,338	152,381	133,978	453,358	819,055
CONE Gathering Commitments	47,250	227,775	385,700	1,040,800	1,701,525
Long-Term Debt	12,968	8,263	1,507,665	1,611,334	3,140,230
Interest on Long-Term Debt	244,977	490,592	491,303	420,741	1,647,613
Capital (Finance) Lease Obligations	9,097	14,782	10,902	26,063	60,844
Interest on Capital (Finance) Lease Obligations	4,005	6,335	4,655	4,161	19,156
Operating Lease Obligations	98,609	168,017	105,010	155,431	527,067
Long-Term Liabilities—Employee Related (a)	227,653	468,513	482,271	2,367,736	3,546,173
Other Long-Term Liabilities (b)	359,314	134,767	88,856	480,304	1,063,241
Total Contractual Obligations (c)	$1,437,569	$1,685,113	$3,210,340	$6,559,928	$12,892,950

(a) Long-Term Liabilities—Employee Related include other post-employment benefits, work-related injuries and illnesses. Estimated salaried retirement contributions required to meet minimum funding standards under ERISA are excluded from the pay-out table due to the uncertainty regarding amounts to be contributed. Estimated 2012 contributions are expected to approximate $110 million.

(b) Other long-term liabilities include mine reclamation and closure and other long-term liability costs.

(c)

The significant obligation table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

Debt

At September 30, 2012, CONSOL Energy had total long-term debt of $3.201 billion outstanding, including the current portion of long-term debt of $22 million. This long-term debt consisted of:

- An aggregate principal amount of $1.5 billion of 8.00% senior unsecured notes due in April 2017. Interest on the notes is payable April 1 and October 1 of each year. Payment of the principal and interest on the notes are guaranteed by most of CONSOL Energy's subsidiaries.

- An aggregate principal amount of $1.25 billion of 8.25% senior unsecured notes due in April 2020. Interest on the notes is payable April 1 and October 1 of each year. Payment of the principal and interest on the notes are guaranteed by most of CONSOL Energy’s subsidiaries.
- An aggregate principal amount of $250 million of 6.375% senior unsecured notes due in March 2021. Interest on the notes is payable March 1 and September 1 of each year. Payment of the principal and interest on the notes are guaranteed by most of CONSOL Energy's subsidiaries.
- An aggregate principal amount of $103 million of industrial revenue bonds which were issued to finance the Baltimore port facility and bear interest at 5.75% per annum and mature in September 2025. Interest on the industrial revenue bonds is payable March 1 and September 1 of each year.
- An aggregate principal amount of $6 million on other various rate notes maturing through June 2031.
- $31 million in advance royalty commitments with an average interest rate of 6.73% per annum.
- An aggregate principal amount of $61 million of capital leases with a weighted average interest rate of 6.36% per annum.

At September 30, 2012, CONSOL Energy also had no outstanding borrowings and had approximately $100 million of letters of credit outstanding under the $1.5 billion senior secured revolving credit facility.
At September 30, 2012, CONSOL Energy had no outstanding borrowings and had $161 million of letters of credit outstanding under the accounts receivable securitization facility.
At September 30, 2012, CNX Gas, a wholly owned subsidiary of CONSOL Energy, had no outstanding borrowings and approximately $70 million of letters of credit outstanding under its $1.0 billion secured revolving credit facility.

Total Equity and Dividends

CONSOL Energy had total equity of $3.8 billion at September 30, 2012 and $3.6 billion at December 31, 2011. Total equity increased primarily due to net income, adjustments to actuarial liabilities, and the amortization of stock-based compensation awards. These increases were offset, in part, by the declaration of dividends, changes in the fair value of cash flow hedges and the issuance of treasury stock. See the Consolidated Statements of Stockholders' Equity in Item 1 of this Form 10-Q for additional details.
Dividend information for the current year to date were as follows:

Declaration Date	Amount Per Share	Record Date	Payment Date
October 26, 2012	$0.125	November 9, 2012	November 23, 2012
July 27, 2012	$0.125	August 10, 2012	August 24, 2012
April 27, 2012	$0.125	May 11, 2012	May 25, 2012
January 27, 2012	$0.125	February 7, 2012	February 21, 2012

The declaration and payment of dividends by CONSOL Energy is subject to the discretion of CONSOL Energy’s Board of Directors, and no assurance can be given that CONSOL Energy will pay dividends in the future. CONSOL Energy’s Board of Directors determines whether dividends will be paid quarterly. The determination to pay dividends will depend upon, among other things, general business conditions, CONSOL Energy’s financial results, contractual and legal restrictions regarding the payment of dividends by CONSOL Energy, planned investments by CONSOL Energy and such other factors as the Board of Directors deems relevant. Our credit facility limits our ability to pay dividends in excess of an annual rate of $0.50 per share when our leverage ratio exceeds 4.50 to 1.00 or our availability is less than or equal to $100 million. The leverage ratio was 2.43 to 1.00 and our availability was approximately $1.4 billion at September 30, 2012. The credit facility does not permit dividend payments in the event of default. The indentures to the 2017, 2020 and 2021 notes limit dividends to $0.50 per share annually unless several conditions are met. Conditions include no defaults, ability to incur additional debt and other payment limitations under the indentures. There were no defaults in the nine months ended September 30, 2012.

Off-Balance Sheet Transactions

CONSOL Energy does not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on CONSOL Energy’s financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the Notes to the Unaudited Consolidated Financial Statements. CONSOL Energy participates in various multi-employer benefit plans such as the UMWA 1974 Pension Plan, the UMWA Combined Benefit Fund and the UMWA 1993 Benefit Plan which generally accepted accounting principles recognize on a pay as you go basis. These benefit arrangements may result in additional liabilities that are not recognized on the balance sheet at September 30,

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2012. The various multi-employer benefit plans are discussed in Note 17—Other Employee Benefit Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of the December 31, 2011 Form 10-K. CONSOL Energy also uses a combination of surety bonds, corporate guarantees and letters of credit to secure our financial obligations for employee-related, environmental, performance and various other items which are not reflected on the balance sheet at September 30, 2012. Management believes these items will expire without being funded. See Note 11—Commitments and Contingencies in the Notes to the Unaudited Consolidated Financial Statements included in Item 1 of this Form 10-Q for additional details of the various financial guarantees that have been issued by CONSOL Energy.

Recent Accounting Pronouncements

In July 2012, the Financial Accounting Standards Board issued update 2012- 2 - Intangibles - Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment. The update is intended to reduce the cost and complexity of performing an impairment test for indefinite-lived intangible assets by simplifying how an entity tests those assets for impairment. The update is also intended to improve the consistency in impairment testing guidance among long-lived asset categories. Previous guidance required an entity to test indefinite-lived intangible assets for impairment by comparing the fair value of the asset with its carrying amount at least on an annual basis. If the carrying amount exceeded its fair value, an entity needed to recognize an impairment loss in the amount of the excess. The amendment to this update allows an entity to first assess the qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. This assessment will determine whether it is necessary to perform quantitative impairment tests. This type of testing results in guidance that is similar to the goodwill impairment testing in Update 2011-08. The amendments are effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012 with early adoption permitted for impairment tests performed as of July 27, 2012. We believe adoption of this new guidance will not have a material impact on CONSOL Energy's financial statements.

Forward-Looking Statements

We are including the following cautionary statement in this Quarterly Report on Form 10-Q to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf, of us. With the exception of historical matters, the matters discussed in this Quarterly Report on Form 10-Q are forward-looking statements (as defined in Section 21E of the Exchange Act) that involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. When we use the words “believe,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “estimate,” “plan,” “predict,” “project,” or their negatives, or other expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this Quarterly Report on Form 10-Q speak only as of the date of this Quarterly Report on Form 10-Q; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- deterioration in global economic conditions in any of the industries in which our customers operate, or sustained uncertainty in financial markets cause conditions we cannot predict;
- a significant or extended decline in prices we receive for our coal and natural gas affecting our operating results and cash flows;

- our customers extending existing contracts or entering into new long-term contracts for coal;
- our reliance on major customers;
- our inability to collect payments from customers if their creditworthiness declines;
- the disruption of rail, barge, gathering, processing and transportation facilities and other systems that deliver our coal and natural gas to market;
- a loss of our competitive position because of the competitive nature of the coal and natural gas industries, or a loss of our competitive position because of overcapacity in these industries impairing our profitability;
- our inability to maintain satisfactory labor relations;
- coal users switching to other fuels in order to comply with various environmental standards related to coal combustion emissions;

- the impact of potential, as well as any adopted regulations relating to greenhouse gas emissions on the demand for coal and natural gas
- foreign currency fluctuations could adversely affect the competitiveness of our coal abroad;
- the risks inherent in coal and natural gas operations being subject to unexpected disruptions, including geological conditions, equipment failure, timing of completion of significant construction or repair of equipment, fires, explosions, accidents and weather conditions which could impact financial results;
- decreases in the availability of, or increases in, the price of commodities or capital equipment used in our mining operations;
- decreases in the availability of, an increase in the prices charged by third party contractors or, failure of third party contractors to provide quality services to us in a timely manner could impact our profitability;
- obtaining and renewing governmental permits and approvals for our coal and gas operations;
- the effects of government regulation on the discharge into the water or air, and the disposal and clean-up of, hazardous substances and wastes generated during our coal and natural gas operations;
- our ability to find adequate water sources for our use in gas drilling, or our ability to dispose of water used or removed from strata in connection with our gas operations at a reasonable cost and within applicable environmental rules;
- the effects of stringent federal and state employee health and safety regulations, including the ability of regulators to shut down a mine or natural gas well;
- the potential for liabilities arising from environmental contamination or alleged environmental contamination in connection with our past or current coal and gas operations;
- the effects of mine closing, reclamation, gas well closing and certain other liabilities;
- uncertainties in estimating our economically recoverable coal and gas reserves;
- costs associated with perfecting title for coal or gas rights on some of our properties;
- the impacts of various asbestos litigation claims;
- the outcomes of various legal proceedings, which are more fully described in our reports filed under the Securities Exchange Act of 1934;
- increased exposure to employee-related long-term liabilities;
- our accruals for obligations for long-term employee benefits are based upon assumptions which, if inaccurate, could result in our being required to expend greater amounts than anticipated;
- due to our participation in an underfunded multi-employer pension plan, we have exposure under that plan that extends beyond what our obligation would be with respect to our employees and in the future we may have to make additional cash contributions to fund the pension plan or incur withdrawal liability;
- lump sum payments made to retiring salaried employees pursuant to our defined benefit pension plan exceeding total service and interest cost in a plan year;
- acquisitions and joint ventures that we recently have completed or entered into or may make in the future including the accuracy of our assessment of the acquired businesses and their risks, achieving any anticipated synergies, integrating the acquisitions and unanticipated changes that could affect assumptions we may have made and divestitures we anticipate may not occur or produce anticipated proceeds including joint venture partners paying anticipated carry obligations;
- the terms of our existing joint ventures restrict our flexibility and actions taken by the other party in our gas joint ventures may impact our financial position;
- the anti-takeover effects of our rights plan could prevent a change of control;
- risks associated with our debt;
- replacing our natural gas reserves, which if not replaced, will cause our gas reserves and gas production to decline;
- our hedging activities may prevent us from benefiting from price increases and may expose us to other risks;
- other factors discussed in our 2011 Form 10-K under “Risk Factors,” as updated by any subsequent Form 10-Qs, which are on file at the Securities and Exchange Commission.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In addition to the risks inherent in operations, CONSOL Energy is exposed to financial, market, political and economic risks. The following discussion provides additional detail regarding CONSOL Energy's exposure to the risks of changing commodity prices, interest rates and foreign exchange rates.

CONSOL Energy is exposed to market price risk in the normal course of selling natural gas production and to a lesser extent in the sale of coal. CONSOL Energy sells coal under both short-term and long-term contracts with fixed price and/or indexed price contracts that reflect market value. CONSOL Energy uses fixed-price contracts, collar-price contracts and derivative commodity instruments that qualify as cash-flow hedges under the Derivatives and Hedging Topic of the Financial Accounting Standards Board Accounting Standards Codification to minimize exposure to market price volatility in the sale of natural gas. Our risk management policy prohibits the use of derivatives for speculative purposes.

CONSOL Energy has established risk management policies and procedures to strengthen the internal control environment of the marketing of commodities produced from its asset base. All of the derivative instruments without other risk assessment procedures are held for purposes other than trading. They are used primarily to mitigate uncertainty, volatility and cover underlying exposures. CONSOL Energy's market risk strategy incorporates fundamental risk management tools to assess market price risk and establish a framework in which management can maintain a portfolio of transactions within pre-defined risk parameters.

CONSOL Energy believes that the use of derivative instruments, along with our risk assessment procedures and internal controls, mitigates our exposure to material risks. However, the use of derivative instruments without other risk assessment procedures could materially affect CONSOL Energy's results of operations depending on market prices. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity.

For a summary of accounting policies related to derivative instruments, see Note 1—Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of CONSOL Energy's 2011 Form 10-K.

A sensitivity analysis has been performed to determine the incremental effect on future earnings, related to open derivative instruments at September 30, 2012. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by $23.5 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by $23.5 million.

CONSOL Energy’s primary exposure to market risk for changes in interest rates relates to our revolving credit facility, under which there were no borrowings outstanding at September 30, 2012. Also, CNX Gas had no borrowings under its revolving credit facility at September 30, 2012.

Almost all of CONSOL Energy’s transactions are denominated in U.S. dollars, and, as a result, it does not have material exposure to currency exchange-rate risks.

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Hedging Volumes

As of October 19, 2012 our hedged volumes for the periods indicated are as follows:

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2012 Fixed Price Volumes					
Hedged Mcf	19,108,632	19,108,632	19,318,617	19,318,617	76,854,498
Weighted Average Hedge Price/Mcf	$5.25	$5.25	$5.25	$5.25	$5.25
2013 Fixed Price Volumes					
Hedged Mcf	16,114,849	16,293,903	16,472,957	16,472,957	65,354,666
Weighted Average Hedge Price/Mcf	$4.73	$4.73	$4.73	$4.73	$4.73
2014 Fixed Price Volumes					
Hedged Mcf	13,559,838	13,710,502	13,861,167	13,861,167	54,992,674
Weighted Average Hedge Price/Mcf	$4.95	$4.95	$4.95	$4.95	$4.95
2015 Fixed Price Volumes					
Hedged Mcf	8,240,277	8,331,836	8,423,395	8,423,395	33,418,903
Weighted Average Hedge Price/Mcf	$4.07	$4.07	$4.07	$4.07	$4.07

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures. CONSOL Energy, under the supervision and with the participation of its management, including CONSOL Energy’s principal executive officer and principal financial officer, evaluated the effectiveness of the Company’s “disclosure controls and procedures,” as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), as of the end of the period covered by this Quarterly Report on Form 10-Q. Based on that evaluation, CONSOL Energy’s principal executive officer and principal financial officer have concluded that the Company’s disclosure controls and procedures are effective as of September 30, 2012 to ensure that information required to be disclosed by CONSOL Energy in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by CONSOL Energy in such reports is accumulated and communicated to CONSOL Energy’s management, including CONSOL Energy’s principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal controls over financial reporting. There were no changes in the Company's internal controls over financial reporting that occurred during the fiscal quarter covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

PART II
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS
The first through the nineteenth paragraphs of Note 11—Commitments and Contingencies in the Notes to the Unaudited Consolidated Financial Statements included in Item 1 of this Form 10-Q are incorporated herein by reference.

ITEM 1A. RISK FACTORS
We have entered into two significant gas joint ventures. These joint ventures restrict our operational and corporate flexibility; actions taken by our joint venture partners may materially impact our financial position and results of operation; and we may not realize the benefits we expect to realize from these joint ventures.

In the second half of 2011 CONSOL Energy, through its principal gas operations subsidiary, CNX Gas Company LLC (CNX Gas Company), entered into joint venture arrangements with Noble Energy, Inc. (Noble Energy) and Hess Ohio Developments, LLC (Hess) regarding our shale gas assets. We sold a 50% undivided interest in approximately 628 thousand net acres of Marcellus shale oil and gas assets to Noble Energy and a 50% undivided interest in nearly 200 thousand net Utica shale acres in Ohio. The following aspects of these joint ventures could materially impact CONSOL Energy:

- The development of these properties is subject to the terms of our joint development agreements with these parties and we no longer have the flexibility to control the development of these properties. For example, the joint development agreements for each of these joint ventures sets forth required capital expenditure programs that each party must participate in unless the parties mutually agree to change such programs or, in certain limited circumstances in the case of the Noble Energy joint development agreement, a party elects to exercise a non-consent right with respect to an entire year. If we do not timely meet our financial commitments under the respective joint venture agreements, our rights to participate in such joint ventures will be adversely affected and the other parties to the joint ventures may have a right to acquire a share of our interest in such joint ventures proportionate to, and in satisfaction of, our unmet financial obligations. In addition, each joint venture party has the right to elect to participate in all acreage and other acquisitions in certain defined areas of mutual interest.
- Each joint development agreement assigns to each party designated areas over which that party will manage and control operations. We could incur liability as a result of action taken by one of our joint venture partners.
- Of the approximately $3.3 billion we anticipate receiving from Noble Energy, approximately $2.1 billion depends upon Noble Energy paying a portion of our share of drilling and development costs for new wells, which we call “carried costs.” We entered into a similar transaction with Hess Ohio Developments, LLC (Hess) in which approximately $534 million of the total anticipated consideration of $594 million is dependent upon Hess paying carried costs. Thus, the benefits we anticipate receiving in the joint ventures depend in part upon the rate at which new wells are drilled and developed in each joint venture, which could fluctuate significantly from period to period. Moreover, the performance of these third party obligations is outside our control. The inability or failure of a joint venturer to pay its portion of development costs, including our carried costs during the carry period, could increase our costs of operations or result in reduced drilling and production of oil and gas or loss of rights to develop the oil and gas properties held by that joint venture;
- Noble Energy's obligation to pay carried costs is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per million British thermal units or “MMBtu” in any three consecutive month period and will remain suspended until average natural gas prices are above $4.00/MMBtu for three consecutive months. As a result of this provision, Noble Energy's obligation to pay carried costs was suspended beginning on December 1, 2011. We cannot predict when this suspension will be lifted and Noble Energy's obligation to pay the carried costs will resume. This suspension has the effect of requiring us to incur our entire 50 percent share of the drilling and completion costs for new wells during the suspension period and delaying receipt of a portion of the value we expect to receive in the transaction.

- The Noble Energy joint development agreement prohibits prior to March 31, 2014, unless Noble Energy consents in its sole discretion, any transfer of our interests in the Noble Energy joint venture assets or our selling or otherwise transferring control of CNX Gas Company. The Hess joint development agreement prohibits prior to October 21, 2014, unless Hess consents in its sole discretion, any transfer of our interests in the Hess joint venture assets. These restrictions may preclude transactions which could be beneficial to our shareholders.
- Disputes between us and our joint venture partners may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

- Under the joint venture agreements, our joint venture partners have the right for a specified period of time to perform due diligence on the title to the oil and gas interests which we conveyed to them. To the extent our joint venture partners assert claims for title defects, we have a specified period of time in which to review and respond to the asserted title defects, as well as to cure them. We are currently in the this review process with Noble and Hess. If Noble or Hess establish any title defects which are not resolved or if the subject acreage is reassigned to CONSOL, then subject to certain deductibles, their aggregate carried cost obligation under the respective joint venture agreements will be reduced by the value the parties previously allocated to the affected acreage in the respective transactions. If a significant percentage of the oil and gas interests we contributed have title defects, the carried costs could be materially reduced and our aggregate share of the drilling and completion costs for wells in these joint ventures could materially increase.

ITEM 4. MINE SAFETY DISCLOSURES

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in exhibit 95 to this quarterly report.

ITEM 6. EXHIBITS

31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety and Health Administration Safety Data.
101	Interactive Data File (Form 10-Q for the quarterly period ended September 30, 2012 furnished in XBRL).

In accordance with SEC Release 33-8238, Exhibits 32.1 and 32.2 are being furnished and not filed.

SIGNATURES

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

Dated: November 1, 2012

CONSOL ENERGY INC.

By: /S/ J. BRETT HARVEY
J. Brett Harvey
Chairman of the Board and Chief Executive Officer
(Duly Authorized Officer and Principal Executive Officer)

By: /S/ WILLIAM J. LYONS
William J. Lyons
Chief Financial Officer and Executive Vice President
(Duly Authorized Officer and Principal Financial and Accounting Officer)