CONSOL Energy Inc
Form 10-K
February 07, 2013

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 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)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock ($.01 par value)	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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
The aggregate market value of voting stock held by nonaffiliates of the registrant as of June 30, 2012, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of the common stock on the New York Stock Exchange on such date was $2,829,700,137.
The number of shares outstanding of the registrant's common stock as of January 17, 2013 is 228,132,961 shares.
DOCUMENTS INCORPORATED BY REFERENCE:
Portions of CONSOL Energy's Proxy Statement for the Annual Meeting of Shareholders to be held on May 8, 2013, are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III.

TABLE OF CONTENTS

FORWARD-LOOKING STATEMENTS

We are including the following cautionary statement in this Annual Report on Form 10-K 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 Annual Report on Form 10-K 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 Annual Report on Form 10-K speak only as of the date of this Annual Report on Form 10-K; 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;
- an extended decline in demand for or 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;
- defects may exist in our chain of title and we may incur additional costs associated with perfecting title for coal or gas rights on some of our properties or failing to acquire these additional rights may result in a reduction of our estimated reserves;
- 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;
- exposure to multi-employer pension plan liabilities;
- minimum funding requirements by the Pension Protection Act of 2006 (the Pension Act) coupled with the significant investment and plan asset losses suffered during the recent economic decline has exposed us to making additional required cash contributions to fund the pension benefit plans which we sponsor and the multi-employer pension benefit plans in which we participate;
- 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 that we recently have completed 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;
- the terms of our existing joint ventures restrict our flexibility, actions taken by the other party in our gas joint ventures may impact our financial position and various circumstances could cause us not to realize the benefits we anticipate receiving from these joint ventures;
- 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;
- changes in federal or state income tax laws, particularly in the area of percentage depletion and intangible drilling costs, could cause our financial position and profitability to deteriorate; and
- other factors discussed in this 2012 Form 10-K under “Risk Factors,” as updated by any subsequent Form 10-Qs, which are on file at the Securities and Exchange Commission.

PART I

ITEM 1. Business

CONSOL Energy's Business Introduction

CONSOL Energy safely and responsibly produces coal and natural gas for global energy and raw material markets, which include the electric power generation industry and the steelmaking industry. During the year ended December 31, 2012, we produced 56.0 million tons of high-British thermal unit (Btu) bituminous coal from eleven mining complexes in the United States, excluding our portion of production from two equity affiliate complexes. During this same period, our natural gas production totaled 156.3 net billion cubic feet equivalent (Bcfe) from approximately 15,000 gross natural gas wells primarily in Appalachia.

Additionally, we provide energy services, including river and dock services, terminal services, industrial supply services, water services and land resource management services.

CONSOL Energy's History
CONSOL Energy was incorporated in Delaware in 1991. Our coal operations began in 1864. CONSOL Energy's beginnings as the “Consolidation Coal Company” in Western Maryland led to growth and expansion through all major coal producing regions in the United States. CONSOL Energy entered the natural gas business in the 1980s to increase the safety and efficiency of our coal mines by capturing methane from coal seams prior to mining, which makes the mining process safer and more efficient. Over the past six years, CONSOL Energy's natural gas business has grown by over 168% to produce 156.3 net Bcfe in 2012. This business has grown from coalbed methane production in Virginia into other unconventional production, such as Marcellus Shale, in the Appalachian basin. This growth was accelerated with the 2010 asset acquisition of the Appalachian Exploration & Production business of Dominion Resources, Inc. (Dominion Acquisition). Subsequently, in August and September 2011, we announced two strategic joint ventures, one with Noble Energy, Inc. (Noble) and one with a subsidiary of Hess Corporation (Hess). These joint ventures allow the acceleration of development of the assets acquired in the Dominion Acquisition and focus on the development of our Marcellus Shale and Utica Shale asset holdings.

CONSOL Energy's Strategy

CONSOL Energy's strategy is to continue to build the Company into a large integrated energy company.

CONSOL Energy defines itself through its core values which are:

- Safety,
- Compliance, and
- Continuous Improvement.

These values are the foundation of CONSOL Energy's identity and are the basis for how management defines continued success. We believe CONSOL Energy's rich resource base, coupled with these core values, allows management to create value for the long-term. The electric power industry generates over two-thirds of its output by burning coal or natural gas, the two fuels we produce. We believe that the use of coal and natural gas will continue for many years as the principal fuel sources for electricity in the United States. Additionally, we believe that as worldwide economies grow, the demand for electricity from fossil fuels will grow as well, resulting in expansion of worldwide demand for our coal and potentially natural gas.

5

U.S. ELECTRIC SUPPLY by ENERGY SOURCE
In percent of total

	Actuals		Preliminary	Projected
	2010	2011	2012	2013
Coal	44.8%	42.3%	37.5%	39.0%
Natural Gas	23.9%	24.7%	30.3%	27.9%
Nuclear	19.6%	19.3%	18.9%	19.2%
Conventional Hydro	6.3%	7.8%	6.8%	6.9%
Renewables	3.9%	4.6%	5.3%	5.8%
Others	1.5%	1.3%	1.2%	1.2%

Source: U.S. Energy Information Administration

Although coal has lost five percent of market share in the U.S. electric generation market (based on preliminary 2012 results), we believe that our efficient, long-lived, well capitalized longwall mines that operate near major U.S. population centers will continue to maintain their existing market share in the U.S. thermal coal market.

We expect natural gas to become a more significant contributor to the domestic electric generation mix as well as fueling industrial growth in the U.S. economy. Also, natural gas may potentially become a significant contributor to the transportation market. Our increasing gas production will allow CONSOL Energy to participate in these growing markets.

The following charts show CONSOL Energy's coal in international and metallurgical markets:

CONSOL Energy's Capital Expenditure Budget

CONSOL Energy expects to invest $835 - $865 million in its coal, gas and water businesses in 2013, after adjusting for certain expected proceeds from asset sales. The projected 2013 net investment includes capital expenditures of $1,290 million to $1,505 million. Capital expenditures were $1,575 million in 2012. The budget reflects both our ability to invest in organic growth opportunities in coal, gas and liquids, while selling assets that have more value to others. Once the BMX Mine development is complete in early 2014, CONSOL Energy does not expect to invest in new major coal growth projects. Therefore, in 2014 and beyond, annual coal investment is expected to approach maintenance-of-production levels of $5 to $6 per ton. CONSOL Energy has the ability to adjust these planned investments should circumstances warrant.

The table below categorizes the 2012 actual capital expenditures and the planned 2013 capital expenditures budget.

	2012 Actual Capital Expenditures (in millions)	Forecasted 2013 Expenditures Low	High
Coal and Other Operations	$921	$410	$520
Gas Operations	528	835	935
Water Operations	126	45	50
Total Capital Expenditures	$1,575	$1,290	$1,505
Less: Asset Sale Proceeds	(647)	(455)	(640)
Net Investments	$928	$835	$865

CONSOL Energy's Operations

The following map provides the location of CONSOL Energy's coal and gas operations by region:
CONSOL Energy Operations Highlights – Coal

We have consistently ranked among the largest coal producers in the United States based upon total revenue, net income and operating cash flow. We produced 56.0 million tons of coal in 2012. Our production of 62.0 million tons of coal in 2011 accounted for approximately 6% of the total tons produced in the United States and almost 14% of the total tons produced east of the Mississippi River during 2011, the latest year for which statistics are available. CONSOL Energy controls approximately 4.2

billion tons of proved and probable coal reserves located in northern Appalachia (66%), the mid-western United States (17%), central Appalachia (16%), and in the western United States (1%) at December 31, 2012. We are one of the premier coal producers in the United States by several measures:

- We produce one of the largest amounts of coal east of the Mississippi River;
- We control one of the largest amounts of recoverable coal reserves east of the Mississippi River;
- We control the fourth largest amount of recoverable coal reserves among United States coal producers; and
- We are one of the largest United States producers of coal from underground mines.

The following table ranks the 20 largest underground mines in the United States by tons of coal produced in calendar year 2011, the latest year for which statistics are available.

MAJOR U.S. UNDERGROUND COAL MINES–2011
In millions of tons

Mine Name	Operating Company	Production
Bailey	CONSOL Energy	10.8
Enlow Fork	CONSOL Energy	10.2
McElroy	CONSOL Energy	9.3
River View	River View Coal, LLC (Alliance)	7.6
Twentymile	Peabody Energy	7.5
Mach No. 1	Williamson Energy, LLC (Foresight Energy)	7.2
Century	American Energy Corp. (Murray)	7.1
Powhatan No. 6	The Ohio Valley Coal Company (Murray)	6.3
Cumberland	Cumberland Coal Resources (Alpha)	6.2
SUFCO	Arch Coal	6.1
Robinson Run	CONSOL Energy	6.0
West Elk	Arch Coal	5.7
Buchanan	CONSOL Energy	5.7
Loveridge	CONSOL Energy	5.6
Warrior	Warrior Coal LLC (Alliance)	5.4
Shoemaker	CONSOL Energy	5.1
Bull Mountain	Signal Peak Energy LLC	5.1
New Era	American Energy Corp. (Murray)	5.0
Blackville No. 2	CONSOL Energy	4.3
San Juan	BHP Billiton-New Mexico Coal	4.0

Source: National Mining Association

CONSOL Energy continues to derive a substantial portion of its revenue from sales of coal to electricity generators in the United States. In 2012, sales to domestic electric generators comprised approximately 68% of coal revenue and 53% of total revenue. For the year ended December 31, 2012, we derived over 10% of our total revenues from sales to two coal customers individually and more than 35% of our total revenue from sales to our four largest coal and gas customers. As natural gas revenue continues to grow, we expect the relative contribution of our largest coal customers to diminish.

CONSOL Energy Operations Highlights – Gas

CONSOL Energy is a leader in developing unconventional gas resources including the early development of coalbed methane (CBM) production in the Eastern United States. Our gas operations produced 156.3 net Bcfe made up of a combination of CBM (56%), which is gas that resides in coal seams, natural gas from the Marcellus Shale (23%), natural gas from various shallow oil and gas sites (19%), and other unconventional reservoirs (2%) for the year ended December 31, 2012. CONSOL Energy reported estimated net proved gas reserves of 4.0 trillion cubic feet at December 31, 2012. These net proved reserves were made up of

CBM (37%), Marcellus Shale (45%), shallow oil and gas (15%) and other (3%). CONSOL Energy controls considerable resource positions in other unconventional shale plays including: Chattanooga, New Albany, Utica, Huron and other shales.

Our position as a gas producer is highlighted by several measures:

- We are one of the largest natural gas producers in Appalachia with approximately 15,000 total gross wells in Appalachia comprising 8% of all Appalachian wells based on 2011 U.S. Energy Information Administration data, the latest year for which statistics are available.
- We are one of the largest CBM producers, with production equal to approximately 40% of total Appalachian CBM production and 75% of Northern Appalachian production (excluding Alabama) based on 2011 U.S. Energy Information Administration data, the latest year for which statistics are available.
- We gather essentially all of our own production independently or through company operated joint ventures, and we operate one of the largest gas gathering networks in Appalachia. We also own or operate over 4,500 miles of gathering pipelines.
- We have been a pioneer in the exploration of unconventional gas including coalbed methane, Marcellus, Utica, Chattanooga, Huron and New Albany Shales.

In 2012, CONSOL Energy's sales of CBM gas comprised approximately 53% of gas revenue and 8% of total revenue. Sales of Marcellus Shale gas for the same time period comprised approximately 19% of gas revenue and 3% of total revenue, and sales of shallow oil and gas comprised 19% of gas revenue and 3% of total revenue.

Coal Competition

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. CONSOL Energy competes against several other large producers and numerous small producers in the United States and overseas. The five largest producers are estimated by the 2011 National Mining Association Survey to have produced approximately 58% (based on tonnage produced) of the total United States production in 2011. The U.S. Department of Energy reported 1,325 active coal mines in the United States in 2011, the latest year for which government statistics are available. Demand for our coal by our principal customers is affected by many factors including:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power, wind or solar;
- environmental and government regulation;
- coal quality;
- transportation costs from the mine to the customer;
- the reliability of fuel supply;
- worldwide demand for steel;
- natural/weather disasters; and
- political changes in international governments.

Continued demand for CONSOL Energy's coal and the prices that CONSOL Energy obtains are affected by demand for electricity, technological developments, environmental and governmental regulation, and the availability and price of competing coal and alternative fuel supplies. We sell coal to foreign electricity generators and to the more specialized metallurgical coal markets, both of which are significantly affected by international demand and competition.

Natural Gas Competition

The United States natural gas industry is highly competitive and more diversified than the coal industry. CONSOL Energy competes with other large producers, as well as thousands of smaller producers, pipeline imports from Canada, and Liquefied Natural Gas (LNG) from around the globe. According to data from the Natural Gas Supply Association and the Energy Information Agency (EIA), the five largest producers of natural gas produced about 20% of dry gas production in the first nine months of 2012. The EIA reported 514,637 producing natural gas wells in the United States in 2011, the latest year for which government statistics are available.

CONSOL Energy's gas operations are primarily in the eastern United States. The gas market is highly fragmented and not dominated by any single producer. We believe that competition within our market is based primarily on natural gas commodity trading fundamentals and pipeline transportation availability to the various markets.

Continued demand for CONSOL Energy's natural gas and the prices that CONSOL Energy obtains are affected by natural gas use in the production of electricity, U.S. manufacturing and the overall strength of the economy, environmental and government regulation, technological developments and the availability and price of competing alternative fuel supplies.

Industry Segments

Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2012, 2011 and 2010 is included in Note 24 - Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

DETAIL COAL OPERATIONS
Mining Complexes

The following table provides the location of CONSOL Energy's active mining complexes and the coal reserves associated with each.
CONSOL ENERGY MINING COMPLEXES
Proven and Probable Assigned and Accessible Coal Reserves as of December 31, 2012 and 2011

Mine/Reserve	Location	Reserve Class	Coal Seam	Average Seam Thickness (feet)	As Received Heat Value(1) (Btu/lb) Typical	Range	Recoverable Reserves(2) Owned (%)	Leased (%)	Tons in Millions 12/31/2012 (4)	12/31/2
ASSIGNED–OPERATING										
Thermal Reserves										
Enlow Fork (3)	Enon, PA	Assigned	Pittsburgh	5.4	12,940	12,860 – 13,060	100%	—%	27.0	28.5
		Accessible	Pittsburgh	5.3	13,040	12,850 – 13,120	79%	21%	232.8	204.5
Bailey (3)	Enon, PA	Assigned	Pittsburgh	5.5	12,950	12,860 – 13,060	46%	54%	92.2	101.6
		Accessible	Pittsburgh	5.7	12,930	12,770 – 13,090	89%	11%	303.0	334.4
McElroy	Glen Easton, WV	Assigned	Pittsburgh	5.7	12,570	12,450 – 12,650	94%	6%	101.8	105.7
		Accessible	Pittsburgh	5.9	12,650	12,490 – 12,700	96%	4%	86.9	90.0
Shoemaker	Moundsville, WV	Assigned	Pittsburgh	5.6	12,300	11,800 – 12,400	100%	—%	62.5	68.3
Loveridge	Metz, WV	Assigned	Pittsburgh	7.5	13,050	12,850 – 13,150	78%	22%	21.5	26.4
		Accessible	Pittsburgh	7.6	13,010	13,010 – 13,010	95%	5%	16.5	13.6
Robinson Run	Shinnston, WV	Assigned	Pittsburgh	7.5	12,950	12,600 – 13,300	84%	16%	45.1	46.7
		Accessible	Pittsburgh	6.6	12,900	12,850 – 12,950	74%	26%	269.3	156.7
Blacksville #2 (3)	Wana, WV	Assigned	Pittsburgh	6.7	13,000	12,800 – 13,150	83%	17%	17.7	20.3
		Accessible	Pittsburgh	6.9	12,950	12,950 – 12,950	99%	1%	16.3	16.5
Amvest-Fola Complex (3)	Bickmore, WV	Assigned	Multiple	4.6	12,380	12,250 – 12,550	86%	14%	73.4	92.2
Miller Creek Complex	Delbarton, WV	Assigned	Multiple	4.1	12,000	11,600 – 12,650	—%	100%	13.4	5.6
		Accessible	Multiple	3.7	12,440	12,440 – 12,440	4%	96%	8.2	—

Metallurgical Reserves										
Buchanan	Mavisdale, VA	Assigned	Pocahontas 3	6.2	13,650	13,400 – 14,000	19%	81%	51.7	58.0
		Accessible	Pocahontas 3	5.9	13,630	13,540 – 13,780	14%	86%	46.3	37.0
Amonate Complex	Amonate, VA	Assigned	Multiple	4.3	13,150	12,850 – 13,350	52%	48%	14.8	4.9
		Accessible	Multiple	5.2	13,110	13,110 – 13,110	100%	—%	6.6	—
Total Assigned Operating and Accessible									1,507.0	1,410.9

11

(1) The heat value shown for Assigned Operating reserves is based on the quality of coal mined and processed during the year ended December 31, 2012. The heat value shown for accessible reserves are based on as received, dry values obtained from drill hole analysis prorated by the associated Assigned Operating reserve values to account for similar mining and processing methods.

(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustments for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam. Reserves are reported only for those coal seams that are controlled by ownership or leases.

(3) A portion of these reserves contain metallurgical qualities and are currently being sold on the metallurgical market.

(4) The table excludes 11 million tons of recoverable reserves which represents CONSOL Energy's portion of tonnage held by two equity affiliates. CONSOL Energy owns a 49% interest in both of these affiliates. Also, excluded from the table above are approximately 209.3 million tons of reserves at December 31, 2012 that are assigned to projects that have not produced coal in 2012. These assigned reserves are in the Northern Appalachia (northern West Virginia and Pennsylvania), Central Appalachia (Virginia and eastern Kentucky), the Western U.S. (Utah) and Illinois Basin (Illinois) regions. These reserves are approximately 64% owned and 36% leased.

CONSOL Energy assigns coal reserves to each of our mining complexes. The amount of coal we assign to a mining complex generally is sufficient to support mining through the duration of our current mining permit. Under federal law, we must renew our mining permits every five years. All assigned reserves have their required permits or governmental approvals, or there is a high probability that these approvals will be secured.

In addition, our mining complexes may have access to additional reserves that have not yet been assigned. We refer to these reserves as accessible. Accessible reserves are proven and probable reserves that can be accessed by an existing mining complex, utilizing the existing infrastructure of the complex to mine and to process the coal in this area. Mining an accessible reserve does not require additional capital spending beyond that required to extend or to continue the normal progression of the mine, such as the sinking of airshafts or the construction of portal facilities.

Some reserves may be accessible by more than one mining complex because of the proximity of many of our mining complexes to one another. In the table above, the accessible reserves indicated for a mining complex are based on our review of current mining plans and reflect our best judgment as to which mining complex is most likely to utilize the reserve.

Assigned and unassigned coal reserves are proven and probable reserves which are either owned or leased. The leases have terms extending up to 30 years and generally provide for renewal through the anticipated life of the associated mine. These renewals are exercisable by the payment of minimum royalties. Under current mining plans, assigned reserves reported will be mined out within the period of existing leases or within the time period of probable lease renewal periods.

Coal Reserves

At December 31, 2012, CONSOL Energy had an estimated 4.2 billion tons of proven and probable reserves, excluding equity affiliates. Reserves are the portion of the proven and probable tonnage that meet CONSOL Energy's economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels.
Reserves are defined in Securities and Exchange Commission (SEC) Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proven and

probable coal reserves are defined by SEC Industry Guide 7 as follows:
Proven (Measured) Reserves- Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so close and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

Probable (Indicated) Reserves- Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Spacing of points of observation for confidence levels in reserve calculations is based on guidelines in U.S. Geological Survey Circular 891 (Coal Resource Classification System of the U.S. Geological Survey). Our estimates for proven reserves have the highest degree of geologic assurance. Estimates for proven reserves are based on points of observation that are equal to or less than 0.5 miles apart. Estimates for probable reserves have a moderate degree of geologic assurance and are computed from points of observation that are between 0.5 to 1.5 miles apart.
An exception is made concerning spacing of observation points with respect to our Pittsburgh coal seam reserves. Because of the well-known continuity of this seam, spacing requirements are 3,000 feet or less for proven reserves and between 3,000 and 8,000 feet for probable reserves.
CONSOL Energy's estimates of proven and probable reserves do not rely on isolated points of observation. Small pods of reserves based on a single observation point are not considered; continuity between observation points over a large area is necessary for proven or probable reserves.
Our reserve estimates are predicated on information obtained from our ongoing exploration drilling and in-mine sampling programs. Data including coal seam elevation, thickness, and, where samples are available, coal quality is entered into a computerized geological database. This information is then combined with data on ownership or control of the mineral and surface interests to determine the extent of reserves in a given area. Reserve estimates include mine recovery rates that reflect CONSOL Energy's experience in various types of underground and surface coal mines.
CONSOL Energy's reserve estimates are based on geological, engineering and market data assembled and analyzed by our staff of geologists and engineers located at individual mines, operations offices and at our principal office. The reserve estimates are reviewed and adjusted annually to reflect production of coal from reserves, analysis of new engineering and geological data, changes in property control, modification of mining methods and other factors.
Information, including the quantity and quality of reserves, coal and surface control, and other information relating to CONSOL Energy's coal reserve and land holdings, is maintained through a system of interrelated computerized databases.
Our estimate of proven and probable coal reserves has been determined by CONSOL Energy's geologists and mining engineers. Our coal reserves are periodically reviewed by an independent third party consultant. In previous years, the independent consultant has reviewed the procedures used by us to prepare our internal estimates, verified the accuracy of our property reserve estimates and retabulated reserve groups according to standard classifications of reliability.
CONSOL Energy's proven and probable coal reserves fall within the range of commercially marketed coals in the United States. The marketability of coal depends on its value-in-use for a particular application, and this is affected by coal quality, such as, sulfur content, ash and heating value. Modern power plant boiler design aspects can compensate for coal quality differences that occur. Therefore, any of CONSOL Energy's coals can be marketed for the electric power generation industry. Additionally, the growth in worldwide demand for metallurgical coals allows some of our proven and probable coal reserves, currently classified as thermal coals, that possess certain qualities to be sold as metallurgical coal. The addition of this cross-over market adds additional assurance to CONSOL Energy that all of its proven and probable coal reserves are commercially marketable.

The following table sets forth our unassigned proven and probable reserves by region:

CONSOL Energy UNASSIGNED Recoverable Coal Reserves as of December 31, 2012 and 2011

		Recoverable Reserves(2)			Recoverable Reserves (tons in Millions)
Coal Producing Region	As Received Heat Value(1) (Btu/lb)	Owned (%)	Leased (%)	Tons in Millions 12/31/2012	12/31/2011
Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia)	11,400 – 13,600	72%	28%	1,424.0	1,448.1
Central Appalachia (Virginia, Southern West Virginia, Eastern Kentucky)	11,400 – 14,100	53%	47%	354.7	421.3
Illinois Basin (Illinois, Western Kentucky, Indiana)	11,600 – 12,000	45%	55%	733.6	750.7
Total		60%	40%	2,512.3	2,620.1

(1) The heat value estimates for Northern Appalachian and Central Appalachian Unassigned coal reserves include adjustments for moisture that may be added during mining or processing as well as for dilution by rock lying above or below the coal seam. The mining and processing methods currently in use are used for these estimates. The heat value estimates for the Illinois Basin, and the Western U.S. Unassigned reserves are based primarily on exploration drill core data that may not include adjustments for moisture added during mining or processing or for dilution by rock lying above or below the coal seam.

(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness, and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustment for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam. Reserves are only reported for those coal seams that are controlled by ownership or leases.

The following table summarizes our proven and probable reserves as of December 31, 2012 by region and type of coal or sulfur content (sulfur content per million British thermal units). Proven and probable reserves include both assigned and unassigned reserves. The table classifies bituminous coal by rank. Rank (High volatile A, B and C) of bituminous coals are classified on the basis of heat value. The table also classifies bituminous coals as medium and low volatile which are classified on the basis of fixed carbon and volatile matter. Coal is ranked by the degree of alteration it has undergone since the initial deposition of the organic material. The lowest ranked coal, lignite, has undergone less transformation than the highest ranked coal, anthracite. From the lowest to the highest rank, the coals are: lignite; sub-bituminous; bituminous and anthracite. The ranking is determined by measuring the fixed carbon to volatile matter ratio and the heat content of the coal. As rank increases, the amount of fixed carbon increases, volatile matter decreases, and heat content increases. Bituminous coals are further characterized by the amount of volatile matter present. Bituminous coals with high volatile matter content are also ranked. High volatile “A” bituminous coals have higher heat content than high volatile “C” bituminous coals. These characterizations of coal allow a user to predict the behavior of a coal when burned in a boiler to produce heat or when it is heated in the absence of oxygen to produce coke for steel production.

CONSOL Energy Proven and Probable Recoverable Coal Reserves
By Producing Region and Product (In Millions of Tons) As of December 31, 2012

By Region	≤ 1.20 lbs. S02/MMBtu Low Btu	Med Btu	High Btu	> 1.20 ≤ 2.50 lbs. S02/MMBtu Low Btu	Med Btu	High Btu	> 2.50 lbs. S02/MMBtu Low Btu	Med Btu	High Btu	Total	Percent By Region
Northern Appalachia:											
Metallurgical(1):											
High Vol A Bituminous	—	—	—	—	—	162.3	—	—	—	162.3	3.8 %
Thermal(1):											
High Vol A Bituminous	—	—	—	—	—	103.5	57.6	109.7	2,305.8	2,576.6	61.0 %
Low Vol Bituminous	—	—	—	—	—	33.6	—	—	—	33.6	0.8 %
Region Total	—	—	—	—	—	299.4	57.6	109.7	2,305.8	2,772.5	65.6 %
Central Appalachia:											
Metallurgical:											
High Vol A Bituminous	—	—	6.2	—	—	46.5	—	—	—	52.7	1.2 %
Med Vol Bituminous	—	3.0	55.9	—	—	2.9	—	—	—	61.8	1.5 %
Low Vol Bituminous	—	—	188.9	—	—	55.2	—	—	—	244.1	5.8 %
Thermal:											
High Vol A Bituminous	33.6	80.4	2.8	42.0	116.9	2.1	9.4	15.0	8.2	310.4	7.3 %
Region Total	33.6	83.4	253.8	42.0	116.9	106.7	9.4	15.0	8.2	669.0	15.8 %
Midwest-Illinois Basin:											
Thermal:											
High Vol B Bituminous	—	—	—	—	63.6	—	—	425.5	—	489.1	11.6 %
High Vol C Bituminous	—	—	—	—	159.5	—	108.3	—	—	267.8	6.3 %
Region Total	—	—	—	—	223.1	—	108.3	425.5	—	756.9	17.9 %
Utah-Emery Field:											
Thermal:											
High Vol B Bituminous	—	17.9	—	—	12.3	—	—	—	—	30.2	0.7 %
Region Total	—	17.9	—	—	12.3	—	—	—	—	30.2	0.7 %
Total Company	33.6	101.3	253.8	42.0	352.3	406.1	175.3	550.2	2,314.0	4,228.6	100.0 %
Percent of Total	0.8 %	2.4 %	6.0 %	1.0 %	8.3 %	9.6 %	4.1 %	13.0 %	54.8 %	100.0 %	

15

The following table classifies CONSOL Energy coals by rank, projected sulfur dioxide emissions and heating value (British thermal units per pound). The table also classifies bituminous coals as high, medium and low volatile which is based on fixed carbon and volatile matter.

CONSOL Energy Proven and Probable Recoverable Coal Reserves
By Product (In Millions of Tons) As of December 31, 2012

	≤ 1.20 lbs. S02/MMBtu			> 1.20 ≤ 2.50 lbs. S02/MMBtu			> 2.50 lbs. S02/MMBtu				
By Region	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Total	Percent By Product
Metallurgical(1):											
High Vol A Bituminous	—	—	6.2	—	—	208.8	—	—	—	215.0	5.1 %
Med Vol Bituminous	—	3.0	55.9	—	—	2.9	—	—	—	61.8	1.5 %
Low Vol Bituminous	—	—	188.9	—	—	55.2	—	—	—	244.1	5.7 %
Total Metallurgical	—	3.0	251.0	—	—	266.9	—	—	—	520.9	12.3 %
Thermal(1):											
High Vol A Bituminous	33.6	80.4	2.8	42.0	116.9	105.6	67.0	124.7	2,314.0	2,887.0	68.3 %
High Vol B Bituminous	—	17.9	—	—	75.9	—	—	425.5	—	519.3	12.3 %
High Vol C Bituminous	—	—	—	—	159.5	—	108.3	—	—	267.8	6.3 %
Low Vol Bituminous	—	—	—	—	—	33.6	—	—	—	33.6	0.8 %
Total Thermal	33.6	98.3	2.8	42.0	352.3	139.2	175.3	550.2	2,314.0	3,707.7	87.7 %
Total	33.6	101.3	253.8	42.0	352.3	406.1	175.3	550.2	2,314.0	4,228.6	100.0 %
Percent of Total	0.8 %	2.4 %	6.0 %	1.0 %	8.3 %	9.6 %	4.1 %	13.0 %	54.8 %	100.0 %	

The tables above excludes 41 million tons of reserves held by two equity affiliates. CONSOL Energy owns 49% of both of these affiliates.

The following table categorizes the relative Btu values (low, medium and high) for each of CONSOL Energy's producing regions in Btu's per pound of coal.

Region	Low	Medium	High
Northern, Central Appalachia and Canada (1)	< 12,500	12,500 – 13,000	> 13,000
Midwest Appalachia	< 11,600	11,600 – 12,000	> 12,000
Northern Powder River Basin	< 8,400	8,400 – 8,800	> 8,800
Colorado and Utah	< 11,000	11,000 – 12,000	> 12,000

Title to coal properties that we lease or purchase and the boundaries of these properties are verified by law firms retained by us at the time we lease or acquire the properties. Consistent with industry practice, abstracts and title reports are reviewed and updated approximately five years prior to planned development or mining of the property. If defects in title or boundaries of undeveloped reserves are discovered in the future, control of and the right to mine reserves could be adversely affected.

The following table sets forth, with respect to properties that we lease to other coal operators, the total royalty tonnage, acreage leased and the amount of income (net of related expenses) we received from royalty payments for the years ended December 31, 2012, 2011 and 2010.

Year	Total Royalty Tonnage (in thousands)	Total Coal Acreage Leased	Total Royalty Income (in thousands)
2012	8,326	271,760	$16,479
2011	8,488	289,833	$17,998
2010	8,606	226,524	$14,073

Royalty tonnage leased to third parties is not included in the amounts of produced tons that we report. Proven and probable reserves do not include reserves attributable to properties that we lease to third parties.

Compliance Compared to Non-Compliance Coal

Coals are sometimes characterized as compliance or non-compliance coal. The term "compliance coal," as it is commonly used in the coal industry, refers to compliance only with former national sulfur dioxide emissions standards and indicates that when burned, the coal will produce emissions that will not exceed 1.2 pounds of sulfur dioxide per million British thermal units (1.2lb S02/MM Btu). A coal considered a compliance coal for meeting this former sulfur dioxide standard may not meet an emission standard for a different pollutant such as mercury, and may not even meet newer sulfur emission standards for all power plants. More recent clean air regulations that further restrict sulfur dioxide emissions significantly reduce the amount of coal that can be used without post-combustion emission control technologies. Currently, a compliance coal will meet the power plant emission standard of 1.2 lb S02/MM Btu of fuel consumed. At December 31, 2012, approximately 0.4 billion tons, or approximately 9%, of our coal reserves, excluding equity affiliates, met that standard as a compliance coal. It is likely that, within several years, no coal will be "compliant" because new federal regulations will require emissions-control technology to be used regardless of the coal's sulfur content. In many cases, our customers have responded to ever-tightening emissions requirements by retrofitting flue gas desulfurization systems (scrubbers) to existing power plants. Because these systems remove sulfur dioxide before it is emitted into the atmosphere, those customers are less concerned about the sulfur content of coal and more concerned about the delivered price per British Thermal Unit (BTU).

As a result of a 1998 court decision forcing the establishment of mercury emissions standards for power plants, the Environmental Protection Agency (EPA) was required to promulgate a regulatory program for controlling mercury. CONSOL Energy coals have mercury contents typical for their rank and location (approximately 0.07-0.15 parts mercury on a dry coal basis). Since CONSOL Energy coals have high heating values, they have lower mercury contents on a weight per energy basis (typically measured in pounds per trillion Btu) than lower rank coals at a given mercury concentration. Eastern bituminous coals also tend to produce a greater proportion of flue gas mercury in the ionic or oxidized form (which is more easily captured by scrubbers installed for sulfur control) than sub-bituminous coal, including coals produced in the Powder River Basin. Both high rank and low rank coals are also amenable to other methods of controlling mercury emissions, such as by activated carbon injection. The Mercury and Air Toxics Rule (MATs) (remanded by the court and reproposed by the EPA in November 2012) requiring reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, and particulate matter may require the installation of additional costly control technology or the implementation of other measures, including trading of emission allowances and switching to alternative fuels. These additional reductions in permissible emission levels of impurities by coal-fired plants will likely make it more costly to operate coal-fired electric power plants and make coal a less attractive fuel alternative for electric power generation in the future. Some states have already adopted a control program for mercury emissions from coal-fired power plants.

Production

In the year ended December 31, 2012, 96% of CONSOL Energy's production came from underground mines and 4% from surface mines. Where the geology is favorable and reserves are sufficient, CONSOL Energy employs longwall mining systems in our underground mines. For the year ended December 31, 2012, 92% of our production came from mines equipped with longwall mining systems. Underground longwall systems are highly mechanized, capital intensive operations. Mines using longwall systems have a low variable cost structure compared with other types of mines and can achieve high productivity levels compared with those of other underground mining methods. Because CONSOL Energy has substantial reserves readily suitable to these operations, CONSOL Energy believes that these longwall mines can increase capacity at a low incremental cost. The following table shows the production, in millions of tons, for CONSOL Energy's mines in the years ended December 31, 2012, 2011 and 2010, the location of each mine, the type of mine, the type of equipment used at each mine, method of transportation and the year each mine was established or acquired by us.

Mine	Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in millions) 2012	2011	2010	Year Established or Acquired
Thermal								
McElroy	Glen Easton, WV	U	LW/CM	CB B	9.4	9.3	10.1	1968
Bailey (3)	Enon, PA	U	LW/CM	R R/B	8.6	8.7	9.8	1984
Enlow Fork (3)	Enon, PA	U	LW/CM	R R/B	8.0	8.3	9.1	1990
Robinson Run (1)	Shinnston, WV	U	LW/CM	R CB	5.0	5.6	5.5	1966
Loveridge	Metz, WV	U	LW/CM	R T	5.8	5.5	5.9	1956
Shoemaker	Moundsville, WV	U	LW/CM	B	5.3	5.1	3.9	1966
Blacksville #2(1)	Wana, WV	U	LW/CM	R R/B T	3.0	4.2	4.5	1970
Miller Creek Complex(2)	Delbarton, WV	U/S	CM/S/L	R T	2.9	2.8	3.0	2004
AMVEST-Fola Complex(1)(2)	Bickmore, WV	U/S	A/S/L/CM	R T	0.8	2.1	1.9	2007
Emery(1)	Emery Co., UT	U/S	CM	T	—	—	1.0	1945
Buchanan-Thermal(1)	Mavisdale, VA	U	LW/CM	R	—	—	0.2	1983
Jones Fork Complex(1)(2)	Mousie, KY	U/S	CM/S/L	R T	—	—	0.1	1992
High Volatile Metallurgical								
Bailey-Met (3)	Enon, PA	U	LW/CM	R R/B	1.5	2.1	1.2	1984
Enlow Fork-Met (3)	Enon, PA	U	LW/CM	R R/B	1.5	1.8	1.1	1990
Robinson Run-Met	Shinnston, WV	U	LW/CM	R CB	—	0.4	—	1966
Blacksville #2(1)-Met	Wana, WV	U	LW/CM	R R/B T	0.2	0.1	—	1970
Loveridge-Met	Metz, WV	U	LW/CM	R T	0.1	0.1	—	1956
AMVEST-Fola Complex(1)(2)-Met	Bickmore, WV	U/S	A/S/L/CM	R T	0.3	0.1	—	2007
AMVEST-Terry Eagle Complex(1)(2)-Met	Jodie, WV	U/S	CM/A/S/L	R T	—	0.1	—	2007
Low Volatile Metallurgical								
Buchanan(1)	Mavisdale, VA	U	LW/CM	R T	3.5	5.7	4.5	1983
Amonate (1)(2)	Amonate, VA	U/S	S/CM	R T	0.1	—	—	2012
Total					56.0	62.0	61.8	
CONSOL Energy Portion of Equity Affiliates								
Harrison Resources(2)(4)	Cadiz, OH	S	S/L	R T	0.4	0.4	0.4	2007
Western Allegheny-Knob Creek(2)(4)	Young Township, PA	U	CM	R T	0.1	0.1	0.1	2010
Total CONSOL Energy Portion of Equity Affiliates					0.5	0.5	0.5	

18

A	–	Auger
S	–	Surface
U	–	Underground
LW	–	Longwall
CM	–	Continuous Miner
S/L	–	Stripping Shovel and Front End Loaders
R	–	Rail
B	–	Barge
R/B	–	Rail to Barge
T	–	Truck
CB	–	Conveyor Belt
(1)	–	Mine was idled for part of the year(s) presented due to market conditions.
(2)	–	Harrison Resources, Miller Creek Complex, AMVEST–Fola Complex, AMVEST–Terry Eagle Complex, Jones Fork Complex, Amonate Complex and Western Allegheny–Knob Creek include facilities operated by independent contractors.
(3)	–	Mine was idle for three weeks due to a structural failure at the above-ground conveyor system at the Bailey Preparation Plant. Production was then resumed at a reduced capacity.
(4)	–	Production amounts represent CONSOL Energy's 49% ownership interest.

Coal Capital Projects

CONSOL Energy expects to invest between $410 million to $520 million for the coal segment and other segment in 2013. This compares to $921 million invested in the coal and other segments in 2012. CONSOL Energy anticipates investing $318 million for maintenance-of-production projects. Other major projects include $166 million for the BMX Mine (see below for BMX description), as well as $80 million for the Enlow Fork overland belt project. The BMX Mine is scheduled for completion during the first quarter of 2014, when 5 million annual tons of high-quality Pittsburgh seam coal will be available to be sold in either the high-vol or thermal markets. In 2012, CONSOL Energy contracted and paid significant deposits to secure replacement longwall mining shields at three of its mining complexes and new longwall mining shields at the BMX mining complex. The company is nearing the end of a process to fund this capital commitment through an operating lease in 2013. This amount has been netted from the expected coal operations capital expenditures.

In 2012, capital projects included the continued development of the BMX Mine. This project is expected to add 5 million tons a year of high-quality Pittsburgh seam coal, which will be sold in either the high-volatile metallurgical or thermal markets. This extension of the Bailey Mine began in 2009 and production from the first longwall panel is expected to start in early 2014. The total cost of the project is expected to be approximately $672 million of which approximately $171 million was incurred in 2012. As of December 31, 2012, total project-to-date expenditures were approximately $346 million. Included within the scope of this project are certain surface facility upgrades at the Bailey Preparation Plant which are necessary in order for the plant to process the additional coal from the BMX Mine. These upgrades include the construction of several new raw and clean coal silos, expansion of existing railroad facilities, and installation of additional raw coal material handling systems.

Construction of a new slope and overland belt at the Enlow Fork Mine in Pennsylvania began in 2010 and is expected to be completed by the end of 2013. Overland belt projects are expected to enhance safety, improve productivity, increase production and reduce costs. Modern conveyor systems typically provide high availability rates, thereby allowing mining equipment to produce at higher levels. Overland belts do not require the daily maintenance of the mine roof that underground haulage systems require allowing manpower to be reduced or redeployed to more productive work. Mine safety is expected to be enhanced by overland belts because older underground belt areas will be sealed. The total cost of the project is expected to be approximately $208 million of which there was approximately

$98 million of expenditures in 2012. As of December 31, 2012, total project-to-date expenditures were approximately $136 million.

Also, in accordance with a consent decree with the U.S Environmental Protection Agency and the West Virginia Environmental Protection Agency, CONSOL Energy continued construction of an advance water processing system (RO) in Northern West Virginia in 2012. The RO will provide a treatment system for the mine water generated from the Robinson Run, Loveridge, and Blacksville #2 Mines to be in compliance with the existing National Pollution Discharge Elimination System (NPDES) permits. Construction was started in April 2011 and final commissioning of the RO system is expected to be complete by the end of May 2013. Expenditures related to the Northern West Virginia plant of $114 million were incurred in 2012 and total costs related to the construction of this plant and related facilities is expected to be approximately $200 million. As of December 31, 2012, total project-to-date expenditures were approximately $162 million.

Coal Marketing and Sales

Our sales of bituminous coal were at average sales price per ton sold as follows:

	Years Ended December 31,		
	2012	2011	2010
Average Sales Price Per Ton Sold– Thermal Coal	$61.99	$58.87	$53.76
Average Sales Price Per Ton Sold– High Volatile Met Coal	$63.76	$78.06	$72.89
Average Sales Price Per Ton Sold– Low Volatile Met Coal	$140.11	$191.81	$146.32
Average Sales Price Per Ton Sold– Total Company	$67.11	$72.25	$61.33

We sell coal produced by our mining complexes and additional coal that is purchased by us for resale from other producers. We maintain United States sales offices in Charlotte, Philadelphia and Pittsburgh. In addition, we sell coal through agents and to brokers and unaffiliated trading companies.

A breakdown of total coal sales is as follows:

	Tons Sold	Percent of Total	
Thermal	49.1	88	%
High Volatile Metallurgical	3.6	6	%
Low Volatile Metallurgical	3.6	6	%
Total tons sold	56.3	100	%

Approximately 68% of our 2012 coal sales were made to U. S. electric generators, 22% of our 2012 coal sales were priced on export markets and 10% of our coal sales were made to other domestic customers. We had approximately 75 customers in 2012. During 2012, two coal customers individually accounted for more than 10% of total revenue, and the top four coal and gas customers accounted for more than 35% of our total revenues.

Coal Contracts

We sell coal to an established customer base through opportunities as a result of strong business relationships, or through a formalized bidding process. Contract volumes range from a single shipment to multi-year agreements for millions of tons of coal. The average contract term is between one to three years. However, several multi-year agreements have terms ranging from five to twenty years. As a normal course of business, efforts are made to renew or extend contracts scheduled to expire. Although there are no guarantees, we generally have been successful in renewing or extending contracts in the past. For the year ended December 31, 2012, over 86% of all the coal we produced was sold under contracts with terms of one year or more.

The following table sets forth as of January 12, 2013, CONSOL Energy's estimated production and sales for 2013 through 2015.
COAL DIVISION GUIDANCE
(Tons in millions)

	Q1 2013	2013	2014	2015
Estimated Coal Production	14.0	56.3	61.6	63.8
Estimated Low-Vol Met Sales	0.9	3.9	5.0	5.1
Tonnage - Firm	0.8	1.5	—	—
Average Price - Sold (firm)	$121.48	$115.63	—	—
Estimated High-Vol Met Sales	1.1	1.8	4.8	6.3
Tonnage - Firm	1.1	1.4	0.2	0.2
Average Price - Sold (firm)	$64.24	$62.95	$75.53	$74.74
Estimated Thermal Sales	11.9	50.1	51.1	51.7
Tonnage - Firm	11.5	48.7	23.7	15.0
Average Price - Sold (firm)	$58.76	$59.06	$59.92	$61.42

Note: While the data in the table are presented as single point estimates, the inherent uncertainty of markets and mining operations means that investors should consider a reasonable range around these estimates. CONSOL Energy has chosen not to forecast prices for open tonnage due to ongoing customer negotiations. In the thermal sales category, the open tonnage includes two items: sold, but unpriced tons and collared tons. There are no collared tons in 2013. 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. Collared tons in 2015 are 8.7 million tons, with a ceiling of $57.43 per ton and a floor of $44.86 per ton. Calendar years 2013, 2014, and 2015 include 0.5, 0.7 and 0.7 million tons, respectively, from Amonate. The Amonate tons are not included in the category breakdowns.

Coal pricing for contracts with terms of one year or less is generally fixed. Coal pricing for multiple-year agreements generally provides the opportunity to periodically adjust the contract prices through pricing mechanisms consisting of one or more of the following:

- Fixed price contracts with pre-established prices; or
- Periodically negotiated prices that reflect market conditions at the time; or
- Price restricted to an agreed-upon percentage increase or decrease; or
- Base-price-plus-escalation methods which allow for periodic price adjustments based on inflation indices, or other negotiated indices.

The volume of coal to be delivered is specified in each of our coal contracts. Although the volume to be delivered under the coal contracts is stipulated, the parties may vary the timing of the deliveries within specified limits.

Coal contracts typically contain force majeure provisions allowing for the suspension of performance by either party for the duration of specified events. Force majeure events include, but are not limited to, labor disputes and unexpected significant geological conditions. Depending on the language of the contract, some contracts may terminate upon continuance of an event of force majeure that extends for a period greater than three to twelve months.

Distribution

Coal is transported from CONSOL Energy's mining complexes to customers by railroad cars, river barges, trucks, conveyor belts or a combination of these means of transportation. We employ transportation specialists who negotiate freight and equipment agreements with various transportation suppliers, including railroads, barge lines, terminal operators, ocean vessel brokers and trucking companies for certain customers.

At December 31, 2012 we owned/operated 21 towboats, 5 harbor boats and a fleet of approximately 600 barges that serve customers along the Ohio, Allegheny, Kanawha and Monongahela Rivers. The barge operation allows us to control delivery schedules and has served as temporary floating storage for coal when land storage is unavailable.

DETAIL GAS OPERATIONS

Our Gas operations are located throughout Appalachia. While CBM remains our largest share of production much of our future growth will likely come from the development of our Marcellus Shale play and the exploration of our Utica Shale play.

Coalbed Methane (CBM)

We have the rights to extract CBM in Virginia from approximately 271,000 net CBM acres, which cover a portion of our coal reserves in Central Appalachia. We produce gas primarily from the Pocahontas #3 seam which is the main coal seam mined by our Buchanan Mine. This seam is generally found at depths of 2,000 feet and generally ranges from 3 to 6 feet thick. The gas content of this seam is typically between 400 and 600 cubic feet of gas per ton of coal in place. In addition, there are as many as 50 thinner seams present in the several hundred feet above the main Pocahontas #3 seam. Collectively, this series of coal seams represents a total thickness ranging from 15 to 40 feet. We have access to core hole data that allows us to determine the amount of coal present, the geologic structure of the coal seam and the gas content of the coal. For 2013, we expect to drill fewer than 100 CBM wells in Virginia, including gob wells which directly support the de-gasifciation of the Buchanan Mine.

We also have the right to extract CBM in northwestern West Virginia and southwestern Pennsylvania from approximately 902,000 net CBM acres, which contain most of our recoverable coal reserves in Northern Appalachia. We produce gas primarily from the Pittsburgh #8 coal seam. This seam is generally found at depths of less than 1,000 feet and generally ranges from 4 to 7 feet thick. The gas content of this seam is typically between 100 and 250 cubic feet of gas per ton of coal in place. There are additional coal seams above and below the Pittsburgh #8 seam. Collectively, this series of coal seams represents a total thickness ranging from 10 to 30 feet. We have access to information that allows us to determine the amount of coal present, the geologic structure of the coal seam and the gas content of the coal.

There are additional coal seams above and below the Pittsburgh #8 seam. Collectively, this series of coal seams represents a total thickness ranging from 10 to 30 feet. We have access to information that allows us to determine the amount of coal present, the geologic structure of the coal seam and the gas content of the coal.

In central Pennsylvania we have the right to extract CBM from approximately 263,000 net CBM acres, which contain most of our recoverable coal reserves as well as significant leases from other coal owners. In addition, we control 810,000 net CBM acres in Illinois, Kentucky, Indiana, and Tennessee. We also have the right to extract CBM on 139,000 net acres in the San Juan Basin, 128,000 net acres in eastern Ohio and central West Virginia, and 20,000 net acres in the Powder River Basin. For 2013, we have no plans to drill CBM wells in these areas.

Marcellus Shale

We have the rights to extract natural gas in Pennsylvania, West Virginia and New York from approximately 347,000 net Marcellus Shale acres at December 31, 2012. In September 2011, CONSOL Energy entered into a joint venture with Noble Energy regarding our Marcellus Shale oil and gas assets and properties in West Virginia and Pennsylvania. The joint venture holds approximately 624,000 net Marcellus Shale acres in those states as well as the producing Marcellus Shale Wells which we had owned. We hold a 50% interest in the joint venture. We also hold a 50% interest in a related gathering company to which we contributed our existing Marcellus Shale gathering assets. Joint operations are conducted in accordance with a joint development agreement.

CONSOL Energy and Noble Energy drilled a record 89 gross wells in the Marcellus Shale in 2012. CONSOL Energy drilled 64 of those wells in the dry gas area of the formation. The geographic breakdown was 45 wells in Southwestern Pennsylvania, 13 wells in Central Pennsylvania, and 6 wells in Northern West Virginia. Noble Energy drilled 25 wells in the wet gas area of the play.

CONSOL Energy also completed 51 Marcellus Shale wells in 2012. The average lateral length was 5,514 feet in 2012, or a 43% increase over the previous year's lateral length of 3,853 feet. These longer drilled laterals enabled the company to perform more hydraulic fracturing, or “fracking,” to complete the wells. In 2012, the average completed well had 18 frack stages, or a 50% increase over the 12 stages from the previous year. Longer lateral lengths and more frack stages per well lead to enhanced well economics. For 2013, the company expects that average lateral lengths could average approximately 6,000 feet.

In 2013, the company expects the Marcellus Shale drilling to be the primary driver of gas production growth. Current plans are for CONSOL Energy to drill 36 wells in the dry gas portion of the formation, while Noble Energy expects to drill

85-90 wells in the wet area of the formation. CONSOL Energy will continue to evaluate the number of dry gas wells for the 2013 program in light of the commodity price curve.
CONSOL Energy and Noble Energy have been emphasizing drilling in the wet area of the formation, since, in the current pricing environment, the sale of liquids into the flow stream is resulting in much-improved well economics.

Shallow Oil and Gas

The shallow oil and gas acreage position of CONSOL Energy is approximately 648,000 net acres mainly in West Virginia, Pennsylvania, Virginia, New York, San Juan Basin and Powder River Basin at December 31, 2012. The majority of our shallow oil and gas leasehold position is held by production and all of it is extensively overlain by existing third party gas gathering and transmission infrastructure. The shallow oil and gas assets provide multiple synergies with our CBM and unconventional shale operations, and the held by production nature of the shallow oil and gas properties affords CONSOL Energy considerable flexibility to choose when to exploit those and other gas assets including shale assets. For 2013, the company is de-emphasizing its shallow oil and gas program, although some small amount of drilling could occur to hold leases.

Other Gas

Utica
CONSOL Energy also controls approximately 83,000 net acres of Utica Shale potential in eastern Ohio at December 31, 2012. Additionally, CONSOL Energy controls a large number of acres in southwestern Pennsylvania and northern West Virginia that contain the rights to the Utica Shale. These acres are disclosed in other plays because the Utica Shale is not the primary drilling target as of December 31, 2012. The thickness of the Utica Shale in this area ranges from 200 to 450 feet.

To facilitate the delineation and the development of the Utica Shale in Ohio, CONSOL Energy entered into a joint venture with Hess Ohio Developments, LLC (Hess) in the fourth quarter of 2011. The Hess joint venture owns approximately 160,000 net acres of Utica Shale rights in Ohio. We hold a 50% interest in the joint venture. Joint operations are conducted in accordance with a joint development agreement.

Further drilling of the Ohio portion of the Utica acreage is planned for 2013. The company plans to drill 11 wells, all of which are expected to be in Noble County, as the program transitions from an exploration play to a development play.

In 2013, Hess currently plans to drill 16 wells in the Ohio counties of Harrison, Jefferson, Guernsey, and Belmont.

New Albany
We control approximately 277,000 net acres of rights to gas in the New Albany Shale in Kentucky, Illinois, and Indiana. The New Albany Shale is a formation containing gaseous hydrocarbons, and our acreage position has thickness of 50-300 feet at an average depth of 2,500-4,000 feet. For 2013, the company does not plan to drill more than a few wells in this area.

Chattanooga
The Chattanooga Shale in Tennessee is a Devonian-age shale found at a depth of approximately 3,500 feet. The shale thickness is between 40-80 feet, and CONSOL Energy has found it to be rich in total organic content. CONSOL Energy has 248,000 net acres of Chattanooga Shale. This largely contiguous acreage is composed of only a small number of leases, a rarity in Appalachia. CONSOL Energy is the operator of all of its Chattanooga Shale wells. For 2013, the company does not plan to drill more than a few wells in this area.

Huron

We have 451,000 net acres of Huron Shale potential in Kentucky, West Virgina, and Virginia; a portion of this acreage has tight sands potential. For 2013, the company does not plan to drill more than a few wells in this area.

Upper Devonian

The Upper Devonian Shale formation lies above the Marcellus Shale formation in southwestern Pennsylvania and northern West Virginia. The company holds a large number of acres that have Upper Devonian potential, generally these acres have not been disclosed separately, since they are not the primary drilling target as of December 31, 2012.

CONSOL Energy drilled its first exploration well in the Upper Devonian Shale formation in Greene County, Pa. in late 2012. This well is expected to be completed in early 2013

Summary of Properties as of December 31, 2012

	CBM Segment	Shallow Oil and Gas Segment	Marcellus Segment	Other Gas Segment	Total
Estimated Net Proved Reserves (million cubic feet equivalent)	1,485,464	583,611	1,805,149	119,234	3,993,458
Percent Developed	75 %	100 %	24 %	40 %	54 %
Net Producing Wells (including gob wells)	4,287	8,341	92	99	12,819
Net Proved Developed Acres	248,425	203,747	5,162	8,058	465,392
Net Proved Undeveloped Acres	54,799	—	18,710	10,065	83,574
Net Unproved Acres(1)	2,229,564	444,722	322,927	1,041,302	4,038,515
Total Net Acres(2)	2,532,788	648,469	346,799	1,059,425	4,587,481

(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable. See Risk Factors in Section 1A. of this Form 10-K.

(2) Acreage amounts are shown under the target strata CONSOL Energy expects to produce, although the reported acre may include rights to multiple gas seams (CBM, Shallow Oil and Gas, Marcellus, etc.). We have reviewed our drilling plans, our acreage rights and used our best judgment to reflect the acre in the strata we expect to produce. As more information is obtained or circumstances change, the acreage classification may change.

Producing Wells and Acreage

Most of our development wells and proved acreage is located in Virginia, West Virginia and Pennsylvania. Some leases are beyond their primary term, but these leases are extended in accordance with their terms as long as certain drilling commitments or other term commitments are satisfied. The following table sets forth, at December 31, 2012, the number of producing wells, developed acreage and undeveloped acreage:

	Gross	Net(1)
Producing Wells (including gob wells)	14,906	12,819
Proved Developed Acreage	555,160	465,392
Proved Undeveloped Acreage	118,384	83,574
Unproven Acreage	4,930,181	4,038,515
Total Acreage	5,603,725	4,587,481

(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable. See Risk Factors in Section 1A. of this Form 10-K.

Development Wells (Net)

During the years ended December 31, 2012, 2011 and 2010 we drilled 95.5, 254.9 and 317.0 net development wells, respectively. Gob wells and wells drilled by operators other than our primary joint venture partners, Noble Energy and Hess Corporation, are excluded in the net development wells. In 2012 there were 141 gross development wells. There were no dry development wells in 2012 or 2011, there was one dry development well in 2010. As of December 31, 2012, 43.5 net developmental wells are still in process. The following table illustrates the net wells drilled by well classification type:

	For the Year Ended December 31,		
	2012	2011	2010
CBM segment	42.5	221.4	184.0
Shallow Oil and Gas segment	2.0	4.0	107.0
Marcellus segment	44.0	17.5	24.0
Other Gas segment	7.0	12.0	2.0
Total Development Wells	95.5	254.9	317.0

For the year ended December 31, 2011, the Marcellus Segment includes 15 gross development wells drilled prior to September 30, 2011. A 50% interest in these wells was subsequently sold to Noble Energy on September 30, 2011.

Exploratory Wells (Net)

During the years ended December 31, 2012, 2011 and 2010, we drilled in the aggregate 21.5, 69.5, and 38.0 net exploratory wells, respectively. As of December 31, 2012, ten net exploratory wells are still in process. In 2012, there were 27 gross exploratory wells. The following table illustrates the exploratory wells drilled by well classification type:

	For the Year Ended December 31,								
	2012			2011			2010		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
CBM segment	—	—	—	—	—	—	—	—	—
Shallow Oil and Gas segment	4.0	7.0	4.0	12.0	1.0	1.0	2.0	—	3.0
Marcellus segment	—	—	0.5	47.5	1.0	—	—	—	—
Other Gas segment (1)	0.5	—	5.5	5.5	—	1.5	18.0	2.0	13.0
Total	4.5	7.0	10.0	65.0	2.0	2.5	20.0	2.0	16.0

(1) For the year ended December 31, 2012, the Other Gas Segment includes five net exploratory wells drilled in the Utica Shale in Ohio, 4.5 of which are still being evaluated.

For the year ended December 31, 2011, the Marcellus Segment includes 41 gross exploratory wells drilled prior to September 30, 2011. A 50% interest in these wells was sold to Noble Energy on September 30, 2011. There were a total of 15 gross exploratory wells drilled after September 30, 2011 under the joint venture agreement with Noble Energy and are reflected in the table above at the applicable ownership percentage.

Reserves

The following table shows our estimated proved developed and proved undeveloped reserves. Reserve information is net of royalty interest. Proved developed and proved undeveloped reserves are reserves that could be commercially recovered under current economic conditions, operating methods and government regulations. Proved developed and proved undeveloped reserves are defined by the Securities and Exchange Commission (SEC).

	Net Reserves (Million cubic feet equivalent) as of December 31,		
	2012	2011	2010
Proved developed reserves	2,165,483	2,135,805	1,931,272
Proved undeveloped reserves	1,827,975	1,344,222	1,800,325
Total proved developed and undeveloped reserves(a)	3,993,458	3,480,027	3,731,597

(a) For additional information on our reserves, see “Other Supplemental Information–Supplemental Gas Data (unaudited) to the Consolidated Financial Statements in Item 8 of this Form 10-K.

Discounted Future Net Cash Flows

The following table shows our estimated future net cash flows and total standardized measure of discounted future net cash flows at 10%:

	Discounted Future Net Cash Flows (Dollars in millions)		
	2012	2011	2010
Future net cash flows	$2,792	$4,877	$5,474
Total PV-10 measure of pre-tax discounted future net cash flows (1)	$1,242	$2,861	$2,780
Total standardized measure of after tax discounted future net cash flows	$736	$1,747	$1,661

(1) We calculate our present value at 10% (PV-10) in accordance with the following table. Management believes that the presentation of the non-Generally Accepted Accounting Principle (GAAP) financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes estimated to be paid, the use of a pre-tax measure is valuable when comparing companies based on reserves. PV-10 is not a measure of the financial or operating performance under GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of the most directly comparable GAAP measure-after-tax discounted future net cash flows.

Reconciliation of PV-10 to Standardized Measure

	As of December 31,		
	2012	2011	2010
	(Dollars in millions)		
Future cash inflows	$11,778	$14,804	$16,724
Future production costs	(4,824)	(5,263)	(5,176)
Future development costs (including abandonments)	(2,451)	(1,675)	(2,720)
Future net cash flows (pre-tax)	4,503	7,866	8,828
10% discount factor	(3,261)	(5,005)	(6,048)
PV-10 (Non-GAAP measure)	1,242	2,861	2,780
Undiscounted income taxes	(1,711)	(2,989)	(3,354)
10% discount factor	1,205	1,875	2,235
Discounted income taxes	(506)	(1,114)	(1,119)
Standardized GAAP measure	$736	$1,747	$1,661

Gas Production

The following table sets forth net sales volumes produced for the periods indicated:

	For the Year Ended December 31,		
	2012	2011	2010
	(in million cubic feet)		
CBM segment	88,149	92,360	91,351
Shallow Oil and Gas segment	29,204	32,168	24,646
Marcellus segment	36,476	26,873	10,408
Other Gas segment	2,495	2,103	1,470
Total Produced	156,324	153,504	127,875

Gas production for 2013, net to CONSOL Energy is expected to be approximately 170 - 180 Bcf.

Gas Capital Projects

CONSOL Energy plans to spend between $835 million and $935 million primarily on developing its extensive Marcellus Shale and Utica Shale assets in 2013. This compares to capital investment of $528 million in the gas segment in 2012. Included in the projected gas segment capital forecast is $160 million to maintain existing production, $600 million on the development of Marcellus Shale assets, $122 million on the development of Utica Shale assets, and less than $65 million on the development of CBM assets. The budget anticipates that the CONSOL/Noble Energy joint venture will drill 126 (gross) horizontal Marcellus Shale wells, including 90 (gross) wells in the liquids-rich area of the play. We will continue to evaluate the number of dry gas wells that we drill in light of the commodity price curve and exercise appropriate capital discipline. CONSOL Energy has assumed no carry from Noble Energy for drilling in the Marcellus Shale, which is dependent on natural gas being priced at or above $4.00 per MMBtu for three consecutive months. Management has included approximately $100 million in drilling carry from Hess Corporation for drilling in the Utica Shale independent of commodity price levels.

Gas Sales

Average Sales Price and Average Lifting Cost

The following table sets forth the total average sales price and the total average lifting cost for all of our gas production for the periods indicated, including intersegment transactions. Total lifting cost is the cost of raising gas to the gathering system and does not include depreciation, depletion or amortization. See Part II Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K for a breakdown by segment.

	For the Year Ended December 31,		
	2012	2011	2010
Average Gas Sales Price Before Effects of Financial Settlements (per thousand cubic feet)	$3.01	$4.27	$4.53
Average Effects of Financial Settlements (per thousand cubic feet)	$1.21	$0.63	$1.30
Average Gas Sales Price Including Effects of Financial Settlements (per thousand cubic feet)	$4.22	$4.90	$5.83
Average Lifting Costs excluding ad valorem and severance taxes (per thousand cubic feet)	$0.58	$0.68	$0.50

We enter into physical gas sales transactions with various counterparties for terms varying in length. Reserves and production estimates are believed to be sufficient to satisfy these obligations. In the past, other than interstate pipeline outages related to maintenance issues or a weather related force majeure event, we have not failed to deliver quantities required under contract. We also enter into various gas swap transactions that qualify as financial cash flow hedges. These gas swap transactions exist parallel to the underlying physical transactions and represented approximately 76.9 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2012 at an average price of $5.25 per thousand cubic feet. These gas swap represented approximately 84.0 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2011 at an average price of $5.21 per thousand cubic feet. As of January 18, 2013, we expect these transactions will cover approximately 69.1 billion cubic feet of our estimated 2013 production at an average price of $4.66 per thousand cubic feet, 58.8 billion cubic feet of our estimated 2014 production at an average price of $4.87 per thousand cubic feet, and 40.6 billion cubic feet of our estimated 2015 production at an average price of $4.10 per thousand cubic feet.

We have purchased firm transportation capacity on various interstate pipelines to ensure gas production flows to market. As of December 31, 2012, we have secured firm transportation capacity to cover more than our 2013, 2014 and 2015 hedged production.

The hedging strategy and information regarding derivative instruments used are outlined in Part II Item 7A Qualitative and Quantitative Disclosures About Market Risk and in Note 22 - Derivative Instruments in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K

Midstream Gas Services

CONSOL Energy has traditionally designed, built and operated natural gas gathering systems to move gas from the wellhead to interstate pipelines or other local sales points. In addition, CONSOL Energy acquired extensive gathering assets in the Dominion Acquisition in 2010. CONSOL Energy now owns or operates approximately 4,500 miles of gas gathering pipelines as well as 250,000 horsepower of compression, of which, approximately 80% is wholly owned with the balance being leased. Along with this compression capacity, CONSOL Energy owns and operates a number of gas processing facilities. This infrastructure is capable of delivering 300 billion cubic feet per year of pipeline quality gas.

On September 30, 2011, in connection with the Noble Energy joint venture for Marcellus Shale wells and leaseholdings, CONE Gathering, LLC was formed ("CONE" or "CONE Gathering"). CONSOL Energy and Noble Energy each own 50% of CONE Gathering. CONE Gathering was formed to develop, operate and own both Noble Energy's and CONSOL Energy's Marcellus Shale gathering system needs. CONSOL Energy operates this equity affiliate.

Upon formation of CONE Gathering, CONSOL Energy contributed its then existing Marcellus Shale gathering assets to CONE Gathering. We believe that the network of right-of-ways, vast surface holdings and experience in building and operating gathering systems in the Appalachian basin will give CONE Gathering an advantage in building the midstream assets required to develop the joint venture's Marcellus Shale position.

CONSOL Energy has had the advantage of having gas production from CBM, which can be lower Btu than pipeline specification, as well as higher Btu Marcellus Shale production which can complement each other by reducing and in some cases eliminating the need for the costly processing of CBM. In addition, the lower Btu CBM production offers an opportunity to blend ethane back into the gas stream when pricing or capacity for ethane markets dictate. This will allow CONSOL Energy more flexibility in bringing Marcellus Shale wells on-line at qualities that meet interstate pipeline specifications.

Other Operations

CONSOL Energy provides other services both to our own operations and to others. These include land services, industrial supply services, terminal services, river and dock services and water services.

Non-Core Mineral Assets and Surface Properties

CONSOL Energy owns significant coal and gas assets that are not in our short or medium term development plans. We continually explore the monetization of these non-core assets by means of sale, lease, contribution to joint ventures, or a combination of the foregoing in order to bring the value of these assets forward for the benefit of our shareholders. We also control a significant amount of surface acreage. This surface acreage is valuable to us in the development of the gathering system for our Marcellus Shale and Utica Shale production. We also derive value from this surface control by granting rights of way or development rights to third parties when we are able to derive appropriate value for our shareholders.

Industrial Supply Services

Fairmont Supply Company, a CONSOL Energy subsidiary, is a general-line distributor of mining, drilling, and industrial supplies in the United States. Fairmont Supply has 38 customer service centers nationwide. Fairmont Supply also provides integrated supply procurement and management services. Integrated supply procurement is a materials management strategy that utilizes a single, full-line distribution to minimize total cost in the maintenance, repair and operating supply chain.

Fairmont Supply provides mine and drilling supplies to CONSOL Energy's mining and gas operations. Approximately 37% of Fairmont Supply's sales in 2012 were made to CONSOL Energy's coal and gas divisions.

Terminal Services

In 2012, approximately 12.7 million tons of coal were shipped through CONSOL Energy's subsidiary, CNX Marine Terminals Inc.'s, exporting terminal in the Port of Baltimore. Approximately 61% of the tonnage shipped was produced by CONSOL Energy coal mines. The terminal can either store coal or load coal directly into vessels from rail cars. It is also one of the few terminals in the United States served by two railroads, Norfolk Southern Corporation and CSX Transportation Inc.

River and Dock Services

CONSOL Energy's river operations, located in Monessen, Pennsylvania, transport coal from our mines, coal from other mines and non-coal commodities from river loadout facilities located primarily along the Monongahela and Ohio Rivers in northern West Virginia and southwestern Pennsylvania. Products are delivered to customers along the Monongahela, Ohio, Kanawha and Allegheny rivers. At December 31, 2012, we owned/operated 21 towboats, 5 harbor boats and approximately 600 barges. In 2012, our river vessels transported a total of 19.3 million tons of coal and other commodities, including 7.9 million tons of coal produced by CONSOL Energy mines.

CONSOL Energy provides dock services for our mines as well as for third parties at our Alicia Dock, located on the Monongahela River in Fayette County, Pennsylvania. CONSOL Energy transfers coal from rail cars to barges for customers that receive coal on the river system.

Water Services

CNX Water Assets LLC, a CONSOL Energy subsidiary, is acquiring and developing existing sources of water in order to support our coal and gas operations, develop business in water sales, promote cutting edge water technologies, treat both acid mine drainage (AMD) water and fracturing water, and reduce our environmental liabilities. CNX Water Assets LLC, operates an advanced waste water treatment plant in support of coal operations as well as fresh water reservoirs. CNX Water Assets objective is to develop and maximize the value of existing water assets, which will be used to provide water for drilling and hydraulic fracturing in support of gas operations and meeting the needs of mining operations. CNX Water also has contracts to provide water to third parties for industrial use from various water sources owned by CONSOL Energy.

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 Shale gas well locations in Greene County served as the site to pilot test this solar powered water purification system. Initial testing of the Epiphany unit demonstrated the efficacy of the approach. Based on results of the pilot test, system improvements and upgrades are being implemented. Testing is ongoing and will be used to evaluate system enhancements in the coming months.

Employee and Labor Relations

At December 31, 2012, CONSOL Energy had 8,896 employees, approximately 31% of whom were represented by the United Mine Workers of America (UMWA). In 2011, the Bituminous Coal Operators Association (BCOA) and the United Mine Workers of America (UMWA) reached a collective bargaining agreement which runs from July 1, 2011 to December 31, 2016. The National Bituminous Coal Wage Agreement of 2011 (2011 NBCWA) covers approximately 2,800 employees of CONSOL Energy subsidiaries. Key elements of the agreement include the following items:

a. A wage increase of $1.00 per hour effective July 1, 2011, and an additional $1.00 per hour increase each January 1st throughout the contract term.
b. Contributions to the 1974 Pension Plan, a multi-employer plan, will continue at the current rate of $5.50 per hour throughout the contract term. New inexperienced miners hired after December 31, 2011 do not participate in the 1974 Pension Plan, but receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014-2016) to the UMWA Cash Deferred Savings Plan (CDSP), which is a 401(k) Plan. UMWA represented employees with over 20 years of credited service under the 1974 Pension Plan receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014-2016) to the CDSP beginning January 1, 2012. Also beginning January 1, 2012, UMWA represented employees have the right to elect to opt-out of future participation in the 1974 Pension Plan and upon such election, receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014 - 2016) to the CDSP.

c. A $1.50 per hour contribution starting January 1, 2012 to a new defined contribution plan to provide retiree bonus payments to eligible retirees in 2014, 2015 and 2016.
d. An increased contribution from $0.50 per hour to $1.10 per hour effective January 1, 2012 to the 1993 Benefit Plan, which is a defined contribution plan providing health benefits to certain retirees.
e. Various other changes related to absenteeism, contributions to various UMWA benefit funds, and eligibility for various vacation days and sick days.

Laws and Regulations

The mining and gas industries are subject to regulation by federal, state and local authorities on matters such as the discharge of materials into the environment, permitting and other licensing requirements, reclamation and restoration of properties after mining or gas operations are completed, management of materials generated by mining and gas operations, pipeline compression and transmission of natural gas and liquids, surface subsidence from underground mining, water discharge effluent limits, water appropriation, air quality standards, protection of wetlands, endangered plant and wildlife protection, limitations on land use, storage of petroleum products and substances that are regarded as hazardous under applicable laws, management of electrical equipment containing polychlorinated biphenyls (PCBs), legislatively mandated benefits for current and retired coal miners, and employee health and safety. In addition, the electric power generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for CONSOL Energy's coal and gas products. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on CONSOL Energy's mining or gas operations or our customers' ability to use coal or gas and may require CONSOL Energy or our customers to change their operations significantly or incur substantial costs.

Numerous governmental permits and approvals are required for mining and gas operations. Regulations provide that a mining permit or modification can be delayed, refused or revoked if an officer, director or a stockholder with a 10% or greater interest in the entity is affiliated with or is in a position to control another entity that has outstanding permit violations. Thus, all mining operations of CONSOL Energy entities must be maintained in compliance to avoid delay in issuance of necessary mining permits. CONSOL Energy is, or may be, required to prepare and present to federal, state or local authorities data and/or analysis pertaining to the effect or impact that any proposed exploration for or production of coal or gas may have upon the environment, the public and employee health and safety. Permits we need may include requirements that may be subject to future restrictive standards or interpreted in a manner which restricts our ability to conduct our mining and gas operations or to do so profitably. Future legislation and administrative regulations may increasingly emphasize the protection of the environment and employee health and safety. As a consequence, the activities of CONSOL Energy may be more closely regulated. Such legislation and regulations, as well as future interpretations of existing laws, may require substantial increases in equipment and operating costs to CONSOL Energy and delays, interruptions or a termination of operations, the extent of which cannot be predicted.

Compliance with these laws has substantially increased the cost of mining and gas production for all domestic coal and gas producers. We post surety performance bonds or letters of credit pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, often including the cost of treating mine water discharge. We also post performance bonds or letters of credit pursuant to state oil and gas laws and regulations to guarantee reclamation of gas well sites and plugging of gas wells. We endeavor to conduct our mining and gas operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements against a backdrop of variable geologic and seasonal conditions, permit exceedances and violations during mining and gas production can and do occur. CONSOL Energy made capital expenditures for environmental control facilities of approximately $126.1 million, $53.1 million and $39.9 million in the years ended December 31, 2012, 2011 and 2010, respectively. In accordance with a consent decree with the U.S. Environmental Protection Agency and the West Virginia Environmental Protection Agency, CONSOL Energy began construction of an advance water processing system in Northern West Virginia in 2011. Construction is expected to be complete in 2013. Expenditures related to the Northern West Virginia plant of $114.0 million and $48.0 million were incurred in 2012 and 2011, respectively, and total costs related to the construction of this plant and related facilities is expected to be approximately $200 million. CONSOL Energy expects to have capital expenditures of $76.3 million in 2013 for environmental control facilities.

Mine Health and Safety Laws

Legislative and regulatory changes have required us to purchase additional safety equipment, construct stronger seals to isolate mined out areas, and engage in additional training. We have also experienced more aggressive inspection protocols and with new regulations the amount of civil penalties have increased.

The actions taken thus far by federal and state governments include requiring:

- the caching of additional supplies of self-contained self-rescuer (SCSR) devices underground;
- the purchase and installation of electronic communication and personal tracking devices underground;
- the placement of refuge chambers, which are structures designed to provide refuge for groups of miners during a mine emergency when evacuation from the mine is not possible, which will provide breathable air for 96 hours;
- the replacement of existing seals in worked-out areas of mines with stronger seals;
- the purchase of new fire resistant conveyor belting underground;
- additional training and testing that creates the need to hire additional employees; and
- more stringent rock dusting requirements.

In December 2012, the Department of Labor released its Regulatory Agenda for the MSHA of Final and Proposed Rules. Final Rules included proximity detection on continuous mining machines and lowering miners' coal dust exposure and the use of personal dust monitors. Proposed Rules included reducing the silica standard and included proximity detection on mobile equipment.

Occupational Safety and Health Act

Our gas operations are subject to regulation under the federal Occupational Safety and Health Act (OSHA) and comparable state laws in some states, all of which regulate health and safety of employees at our gas operations. Also, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced by our gas operations and that this information be provided to employees, state and local governments and the public.

Black Lung Legislation

Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to:

- current and former coal miners totally disabled from black lung disease;
- certain survivors of a miner who dies from black lung disease or pneumoconiosis; and
- a trust fund for the payment of benefits and medical expenses to claimants whose last mine employment was before January 1, 1970, where no responsible coal mine operator has been identified for claims (where a miner's last coal employment was after December 31, 1969), or where the responsible coal mine operator has defaulted on the payment of such benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

The Patient Protection and Affordable Care Act (PPACA) made two changes to the Federal Black Lung Benefits Act. First, it provided changes to the legal criteria used to assess and award claims by creating a legal presumption that miners are entitled to benefits if they have worked at least 15 years in underground coal mines, or in similar conditions, and suffer from a totally disabling lung disease. To rebut this presumption, a coal company would have to prove that a miner did not have black lung or that the disease was not caused by the miner's work. Second, it changed the law so black lung benefits will continue to be paid to dependent survivors when the miner passes away, regardless of the cause of the miner's death.

In addition to the federal legislation, we are also liable under various state statutes for black lung claims.

Retiree Health Benefits Legislation

The Coal Industry Retiree Health Benefit Act of 1992 (the Act) established the Combined Benefit Fund (the Combined Fund). The Combined Fund provides medical and death benefits for all beneficiaries including orphan retirees of the former United Mine Workers of America (UMWA) Benefit Trusts who were actually receiving benefits as of July 20, 1992. The Act also created a second benefit fund for UMWA retirees, the 1992 Benefit Plan. The 1992 Benefit Plan principally provides medical and death benefits to orphan UMWA-represented members eligible for retirement on February 1, 1993, and who actually retired between July 20, 1992 and September 30, 1994. The Act provides for the assignment of beneficiaries to former signatory employers or related companies and the allocation of responsibility for unassigned beneficiaries (referred to as orphans) to the assigned operators. The task of calculating the annual per beneficiary premium that assigned operators are obligated to pay to the Combined Fund is the responsibility of the Commissioner of Social Security.

The UMWA 1993 Benefit Plan is a defined contribution plan that was created as the result of negotiations for the National Bituminous Coal Wage Agreement (NBCWA) of 1993. This plan provides health care benefits to orphan UMWA retirees who are not eligible to participate in the Combined Fund, the 1992 Benefit Fund, or whose last employer signed the 1993 NBCWA or a later NBCWA, and subsequently goes out of business.

The Act requires some of our signatory subsidiaries to make premium payments to the Combined Fund and to the 1992 Benefit Plan for the cost of our retirees and orphan retirees in those plans. In addition, the NBCWA of 2011 requires our signatory subsidiaries to make specified payments to the 1993 Benefit Plan through 2016. The Tax Relief and Health Care Act of 2006 (the 2006 Act) provides additional federal funding for these orphan costs by authorizing general fund revenues and transfers of interest from the Abandoned Mine Land (AML) trust fund. The additional federal funding, depending upon its magnitude and the amount of orphan benefits payable, should cover the orphan premium payments due under the Combined Fund as well as the orphan premium payments due under the 1992 Benefit Plan. Federal contributions were 100% in 2012 and are expected to continue to be 100% in 2013 and beyond. In addition, federal contributions cover the costs for those orphan retirees as of December 31, 2006 under the 1993 Benefit Plan. Under the 2006 Act, these general fund contributions to the Combined Fund, the 1992 Benefit Plan and the 1993 Benefit Plan and certain AML payments to the states and Indian tribes are collectively limited by an aggregate annual cap of $490 million. These federal contributions do not apply to our subsidiaries' assigned retired miners, and therefore our subsidiaries will continue to make premium payments for our assigned retired miners who receive benefits from the Combined Fund, the 1992 Benefit Plan and for certain beneficiaries of the 1993 Benefit Plan. In addition, our subsidiaries remain responsible for making orphan premium payments to the Combined Fund and 1992 Benefit Plan to the extent that the federal contributions are not sufficient to cover the benefits.

Pension Protection Act

The Pension Protection Act of 2006 (the Pension Act) simplified and transformed rules governing the funding of defined benefit plans, accelerated funding obligations of employers, made permanent certain provisions of the Economic Growth and Tax Relief Reconciliation Act of 2001 (EGTRRA), made permanent the diversification rights and investment education provisions for plan participants and encourages automatic enrollment in defined contribution 401(k) plans. In general, most provisions of the Pension Act of 2006 were effective for plan years beginning on or after December 31, 2008. Plans generally are required to set a funding target of 100% of the present value of accrued benefits and sponsors are required to amortize unfunded liabilities over a seven year period. The Pension Act includes a funding target of 100% after 2010. Plans with a funded ratio of less than 80%, or less than 70% using special assumptions, will be deemed to be "at risk" and will be subject to additional funding requirements. The 2012 plan year funding ratio of CONSOL Energy's salary retirement plan was 112%. The funding ratio is subject to year over year volatility and Internal Revenue Service's calculation guidelines.

Environmental Laws

CONSOL Energy is subject to various federal environmental laws, including:

- the Surface Mining Control and Reclamation Act of 1977,
- the Clean Air Act,
- the Clean Water Act,
- the Endangered Species Act,
- the Resource Conservation and Recovery Act,
- the Comprehensive Environmental Response, Compensation and Liability Act,
- the Toxic Substances Control Act, and
- the Emergency Planning and Community Right to Know Act,

as administered and enforced by the United States Environmental Protection Agency (EPA) and/or authorized federal or state agencies, as well as state laws of similar scope, and other state environmental and conservation laws in each state in which CONSOL Energy operates.

These environmental laws require reporting, permitting and/or approval of many aspects of coal mining and gas operations. Both federal and state inspectors regularly visit mines and other facilities to ensure compliance. CONSOL Energy has an ISO14001-compliant Environmental Management System designed to ensure compliance with such environmental laws and regulations.

Given the retroactive nature of certain environmental laws, CONSOL Energy has incurred, and may in the future incur liabilities in connection with properties and facilities currently or previously owned or operated. These liabilities may be increased to include sites to which CONSOL Energy or our subsidiaries sent waste materials.

Surface Mining Control and Reclamation Act

The federal Surface Mining Control and Reclamation Act (SMCRA) establishes minimum national operational, reclamation and closure standards for all surface mines as well as most aspects of deep mines. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. Permits for all mining operations must be obtained from the Office of Surface Mining (OSM) or, where state regulatory agencies have adopted federally approved state programs under SMCRA, the appropriate state regulatory authority. States that operate federally approved state programs may impose standards which are more stringent than the requirements of SMCRA and OSM's regulations and in many instances have done so. All states in which CONSOL Energy's active mining operations are located have achieved primary jurisdiction for enforcement of SMCRA through approved state programs.

SMCRA permit provisions include requirements for coal exploration; baseline environmental data collection and analysis; mine plan development; topsoil removal, storage and replacement; selective handling of overburden materials; mine pit backfilling and grading; protection of the hydrologic balance; subsidence control for underground mines; refuse disposal plans; surface drainage control; mine drainage and mine discharge control and treatment; and site reclamation. All states also impose an obligation on surface mining operations to restore or replace domestic, agricultural or industrial water supplies and on underground mine operations to restore or replace drinking, domestic or residential water supplies adversely affected by such operations. In addition, SMCRA imposes a reclamation fee on all current mining operations, the proceeds of which are deposited in the Abandoned Mine Reclamation Fund (AML Fund), which is used to restore unreclaimed and abandoned mine lands mined before 1977. The current per ton fee is $0.315 per ton for surface mined coal and $0.135 per ton for underground mined coal. From October 1, 2012 through September 30, 2021, the fees will be $0.280 per ton for surface mined coal and $0.120 per ton for underground mined coal.

OSM is currently considering modifications to the existing stream buffer zone regulation, which amendments are referred to as the Stream Protection Rule. An advanced notice of proposed rulemaking (ANPR) was published in November 2009. Based on the ANPR, the proposed rule would apply to surface mining as well as underground mining activities that may impact streams. Although it is too early to predict what the impacts of the proposed amendments will be, all of the alternatives identified in the ANPR could result in loss of access to significant amounts of coal and/or significant increases in reclamation costs. In Pennsylvania, where CONSOL Energy operates two longwall mines, approximately $25.8 million, $29.4 million and $21.8 million of expenses were incurred during the years ended December 31, 2012, 2011 and 2010, respectively, to mitigate and repair impacts on streams from subsidence. With respect to subsidence impacts to streams, the regulatory requirement to minimize impacts to the hydrological balance could cause CONSOL Energy to change mine plans, to incur significant costs, and potentially even shut down mines in order to meet compliance requirements. We currently estimate expenses related to subsidence of streams in Pennsylvania will be approximately $20.2 million for the year ended December 31, 2013.

Clean Air Act and Related Regulations

The federal Clean Air Act and similar state laws and regulations which regulate emissions into the air, affect coal mining, coal handling and processing, and gas production and processing operations primarily through permitting and/or emissions control requirements.

The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of the coal fired electric power generating plants operated by our customers. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. Carbon dioxide, a greenhouse gas, is also emitted when coal is burned. Environmental regulations governing emissions from coal-fired electric generating plants could affect demand for coal as a fuel source and affect the volume of our sales.

In 2012, the EPA promulgated or finalized several rulemakings impacting coal generating facilities. Two of these were final rules for new source performance standards for coal and oil fueled power plants in the Utility Maximum Control Technology (UMACT) rule which includes more stringent new source performance standards (NSPS) for particulate matter (PM), SO_2 and NO_X and the Mercury and Air Toxics Standards (MATS) rule which sets new mercury and air toxic standards. In November 2012, EPA published a notice of reconsideration of certain aspects of the UMACT and MATS rules. EPA proposes to raise the emission limits for mercury, hydrogen chloride and particulate matter in line with the reconsideration petitions of what has been deemed achievable by emissions control manufacturers. In addition, in August 2012, the U.S. Court of Appeals in Washington, DC invalidated EPA's 2011 Cross-State Air Pollution Rule which was intended to regulate sulfur dioxide (SO2), nitrogen dioxide (NOx) and fine particulate matter. The Court ruled that the agency had overstepped its bounds and vacated the rulemaking, ordering the agency to continue to enforce the Clean Air Interstate Rule promulgated in 2005 until a viable replacement to the cross-state regulation could be issued. On October 5, 2012, EPA filed a petition for an en banc review of the August 2012 decision with the U.S. Court of Appeals in Washington, DC. The decision on the en banc review is currently pending.

On March 27, 2012, the U.S. Environmental Protection Agency (EPA) proposed standards for the emission of greenhouse gases (GHG) from new and reconstructed electric generating units at power plants. Such regulations could significantly increase the cost of generation of electricity at coal fired facilities and could make competing forms of electricity generation more competitive.

The Clean Air Act and comparable state laws restrict the emission of air pollutants from compressor stations and other equipment and facilities used in our gas operations. We are required to obtain pre-approval for construction or modification of certain facilities, to meet stringent air permit requirements, or to use specific equipment, technologies or best management practices to control emissions. On August 16, 2012, the EPA published final revisions to the New Source Performance Standards (NSPS) to regulate emissions of volatile organic compounds (VOCs) and sulfur dioxide (SO_2) from various oil and gas exploration, production, processing and transportation facilities and to the National Emission Standards for Hazardous Air Pollutants (NESHAPS) to further regulate emissions from the oil and natural gas production sector and the transmission and storage of natural gas. In September 2009, the EPA finalized the Mandatory Reporting of Greenhouse Gas Rule. The current version of this rule requires annual reporting of emissions from coal mines, gas wells and associated facilities.

Clean Water Act

The federal Clean Water Act (CWA) and corresponding state laws affect coal and gas operations by regulating discharges into surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. The Clean Water Act and corresponding state laws include requirements for: improvement of designated "impaired waters" (not meeting state water quality standards) through the use of effluent limitations; anti-degradation regulations which protect state designated "high quality/exceptional use" streams by restricting or prohibiting discharges; requirements to treat discharges from coal mining properties for non-traditional pollutants, such as chlorides, selenium and dissolved solids; for minimizing impacts and compensating for unavoidable impacts resulting from discharges of fill materials to regulated streams and wetlands; and the requirements to dispose of produced wastes and other oil and gas wastes at approved disposal facilities. In addition, the Spill Prevention, Control and Countermeasure (SPCC) requirements of the CWA apply to all CONSOL Energy operations that use or produce fluids, including brine and oil, and require that plans be in place to address any spills and that secondary containment be installed around all tanks. These requirements may cause CONSOL Energy to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

In order to obtain a permit for surface coal mining activities, including valley fills associated with steep slope mining, an operator must obtain a permit for the discharge of fill material from the Army Corps of Engineers (the COE) pursuant to Section 404 of the Clean Water Act and must obtain a discharge permit from the state regulatory authority under the state counterpart to Section 402 of the Clean Water Act authorizing the issuance of national pollutant discharge elimination permits or NPDES permits. Beginning in early 2009, the EPA took a number of initiatives that have resulted in delays and obstruction of the issuance of such permits for surface mining operation in the states of Kentucky, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia (designated as "Appalachian Surface Coal Mining"). Increased oversight of delegated state programmatic authority, coupled with individual permit review and additional requirements imposed by the EPA, has resulted in delays in the review and issuance of permits for surface coal mining operations, including applications for surface facilities for underground mines, such as applications for coal refuse disposal areas. On July 31, 2012 the U.S. District Court for the District of Columbia set aside EPA guidance issued in April 2010 designed to address water quality for coal mines in Appalachia.

Thus far, CONSOL Energy subsidiaries have been able to continue operating their existing mines. However, CONSOL Energy was affected by a delay in permitting in 2012 for a new coal mine in Mingo County, WV, which resulted in a Worker Adjustment and Retraining Notification Act (WARN) notice being issued for employees scheduled to begin work on the new mine. Since 2007, CONSOL Energy has undertaken permitting activities to permit a new surface mine with a post mine land use plan for a five mile stretch of connecting highway that is part of the King Coal Highway corridor. CONSOL of Kentucky entered into a Memorandum of Understanding in conjunction with the Federal Department of Highways Administration and the U.S. Army Corps of Engineers, to coordinate the design of the valley fills to serve as highway infrastructure. However, the EPA objected to CONSOL Energy's water discharge permit on the grounds of their April 2010 Appalachian guidance, which resulted in CONSOL Energy's issuance of a WARN notice on October 30, 2012 for 145 employees who were planned to work at the new coal mine. CONSOL Energy was able, in this instance, to redeploy these employees to work at another adjacent coal mine property for which a permit was already issued. However, there is no assurance that the permit for a new coal mine will be issued, or that CONSOL Energy would be able to re-deploy its employees under future similar circumstances.

Pursuant to a Congressional requirement in the EPA's 2010 budget appropriation, the EPA must conduct a comprehensive study of the potential adverse impact that hydraulic fracturing may have on water quality and public health. Hydraulic fracturing is a way of producing gas from tight rock formations such as the Barnett and Marcellus shales. The EPA initiated the study in early January 2011 with a final report to be published in 2014. The EPA has also announced plans to conduct a review of water produced in conjunction with the production of Coal Bed Methane (CBM) to determine whether its disposal should be further regulated.

Endangered Species Act

The Federal Endangered Species Act (ESA) and similar state laws protect species threatened with extinction. Protection of endangered and threatened species may cause us to modify mining plans, gas well pad siting or pipeline right of ways, or develop and implement species-specific protection and enhancement plans to avoid or minimize impacts to endangered species or their habitats. A number of species indigenous to the areas where we operate are protected under the ESA. Based on the species that have been identified and the current application of applicable laws and regulations, we do not believe that there are any species protected under the ESA or state laws that would materially and adversely affect our ability to mine coal or produce gas from our properties.

Comprehensive Environmental Response, Compensation and Liability Act (Superfund)

The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) and similar state laws create liabilities for the investigation and remediation of releases of hazardous substances into the environment and for damages to natural resources. We could incur liability under CERCLA relative to our coal or gas operations. Our current and former coal mining operations incur, and will continue to incur, expenditures associated with the investigation and remediation of facilities and environmental conditions, including underground storage tanks, solid and hazardous waste disposal and other matters under Superfund and similar state environmental laws. We also must comply with reporting requirements under the Emergency Planning and Community Right-to-Know Act and the Toxic Substances Control Act.

From time to time, we have been the subject of administrative proceedings, litigation and investigations relating to sites that have released hazardous substances. We have been in the past and currently are named as a potentially responsible party at Superfund sites. We may become involved in future proceedings, litigation or investigations and incur liabilities that could be materially adverse to us.

Resource Conservation and Recovery Act

The federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws and regulations affect coal mining and gas operations by imposing requirements for the treatment, storage and disposal of hazardous wastes. Facilities at which hazardous wastes have been treated, stored or disposed are subject to corrective action orders issued by the EPA which could adversely affect our results, financial condition and cash flows.

In 2010, the EPA proposed options for the regulation of Coal Combustion Residuals from the electric power sector. A final decision has not yet been issued. Depending on the outcome of that decision, demand for coal fired electricity generation could be adversely impacted.

Federal Regulation of the Sale and Transportation of Gas

Various aspects of our gas operations are regulated by agencies of the federal government. The Federal Energy Regulatory Commission regulates the transportation and sale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas

Wellhead Decontrol Act, which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. While "first sales" by producers of natural gas, and all sales of condensate and natural gas liquids can be made currently at uncontrolled market prices, Congress could reenact price controls in the future.

Regulations and orders set forth by the Federal Energy Regulatory Commission also impact our gas business to a certain degree. Although the Federal Energy Regulatory Commission does not directly regulate our gas production activities, the Federal Energy Regulatory Commission has stated that it intends for certain of its orders to foster increased competition within all phases of the natural gas industry. Additionally, the Federal Energy Regulatory Commission continues to review its transportation regulations, including whether to allocate all short-term capacity on the basis of competitive auctions and whether changes to its long-term transportation policies may also be appropriate to avoid a market bias toward short-term

contracts. Additional Federal Energy Regulatory Commission orders have been adopted based on this review with the goal of increasing competition for natural gas markets and transportation.
The Federal Energy Regulatory Commission has also issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the Federal Energy Regulatory Commission does not have jurisdiction over services provided by these facilities, then such facilities and services may be subject to regulation by state authorities in accordance with state law. Changes in regulations or policy underlying federal natural gas pipeline safety requirements could also impact services and costs. In addition, the Federal Energy Regulatory Commission's approval of transfers of previously-regulated gathering systems to independent or pipeline affiliated gathering companies that are not subject to Federal Energy Regulatory Commission regulation may affect competition for gathering or natural gas marketing services in areas served by those systems and thus may affect both the costs and the nature of gathering services that will be available to interested producers or shippers in the future.

We own certain natural gas pipeline facilities that we believe meet the traditional tests which the Federal Energy Regulatory Commission has used to establish a pipeline's status as a gatherer not subject to the Federal Energy Regulatory Commission jurisdiction.

Additional proposals and proceedings that might affect the gas industry may be pending before Congress, the Federal Energy Regulatory Commission, the Minerals Management Service, state commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a significantly adverse effect upon the capital expenditures, earnings or competitive position of CONSOL Energy or its subsidiaries. No material portion of our business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the federal government.

State Regulation of Gas Operations

Our gas operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the siting and construction of well pads and roads, drilling of wells, bonding requirements, protection of ground water and surface water resources and protection of drinking water supplies, the method of drilling and casing wells, the surface use and restoration of well sites, gas flaring, the plugging and abandoning of wells, the disposal of fluids used in connection with operations, and gas operations producing coalbed methane in relation to active mining. A number of states have either enacted new laws or may be considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. Our gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although we do not believe that they would be affected by such regulation any differently than other natural gas producers or gatherers. However, these regulatory burdens may affect profitability, and we are unable to predict the future cost or impact of complying with such regulations.

Ownership of Mineral Rights

CONSOL Energy acquires ownership or leasehold rights to coal and gas properties prior to conducting operations on those properties. As is customary in the coal and gas industries, we have generally conducted only a summary review of the title to coal and gas rights that are not in our development plans, but which we believe we control. This summary review is conducted at the time of acquisition or as part of a review of our land records to determine control of mineral rights. Given CONSOL Energy's long history as a coal producer, we believe we have a well-developed ownership position relating to our coal control; however, our ownership of oil and gas rights, particularly those rights that we acquired in connection with our historic coal operations and some of the rights we acquired from Dominion is less developed. As we continue to review our land records and confirm title in anticipation of development, we expect that adjustments to our ownership position (either increases or decreases) will be required.

Prior to the commencement of development operations on coal or gas properties, we conduct a thorough title examination and perform curative work with respect to significant defects. We generally will not commence operations on a property until we have cured any material title defects on such property. We are typically responsible for the cost of curing any title defects. In addition, the acquisition of the necessary rights may not be feasible in some cases. Our discovering title defects which we are unable to cure may adversely impact our ability to develop those properties and we may have to reduce our estimated gas reserves including our proved undeveloped reserves. We have completed title work on substantially all of our coal and gas producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the industry. We also transferred significant rights in undeveloped shale gas properties to Noble Energy and Hess joint ventures. Our joint venture partners have been conducting due diligence on the properties we transferred and we are in the process of reviewing defects they have asserted. 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.

A recent decision by the intermediate appellate court in Pennsylvania in a case captioned Butler v. Powers (Pa. Superior Ct., No. 1795 MDA 2010) did not change the law of Pennsylvania with respect to the ownership of Marcellus Shale gas rights, but in remanding the case to the trial court for further proceedings, it called into question the applicability of a long-standing presumption known as the Dunham Rule to gas in the Marcellus Shale. The Dunham Rule is a presumption that a reservation or conveyance of minerals does not reserve or convey oil and gas absent an express reference to oil and gas. An appeal of the Butler v. Powers case is pending before the Pennsylvania Supreme Court. We believe that the Pennsylvania courts will ultimately confirm that the Dunham Rule applies to Marcellus Shale gas; however, if the Pennsylvania courts were to hold otherwise, we could be exposed to lawsuits challenging our rights to Marcellus Shale gas in some of our Pennsylvania properties where our rights derive from persons who did not also own the mineral rights and we may have to incur substantial additional costs to perfect our gas title in those Pennsylvania properties.

The ownership of CBM is an issue under the laws of some states, including states in which we operate. The following summary sets forth an analysis of provisions of Pennsylvania, Virginia and West Virginia law relating to the ownership of CBM. These summaries do not purport to be complete and are qualified in their entirety by reference to the provisions of applicable law and rights and the laws relating to traditional natural gas resources may differ materially from the rights related to CBM. These summaries are based on current law as of the date of this Annual Report on Form 10-K.

Pennsylvania

In Pennsylvania, CBM that remains inside the coal seam is generally the property of the owner of that coal seam where the gas is located. CBM can be sold in place or leased by the coal owner to another party such as a producer who then would have the right to extract the gas from the coal seam under the terms of the agreement with the coal owner. Once the gas migrates from the coal into other strata, the coal owner no longer has clear title to that migrated gas. As a result, in certain circumstances in Pennsylvania (e.g., in a gob or mine void), we may be required to obtain other property interests (beyond ownership or leasehold interest in the coal rights or CBM) in order to extract gas that is no longer located in the coal seam. We believe that under Pennsylvania law, a coal lessee under a lease to exhaustion would be in the same position as the coal owner with respect to ownership of the CBM.

Virginia

The Virginia Supreme Court has stated that the grant of coal rights only does not include rights to CBM, absent evidence to the contrary. The situation may be different if there is any expression in the severance deed indicating that more than mere coal is conveyed. Virginia courts have also found that the owner of the CBM does not have the right to fracture the coal in order to retrieve the CBM and that the coal operator has the right to ventilate the CBM in the course of mining.

In Virginia, we believe that we control the relevant property rights in order to capture gas from our producing properties. When necessary, we utilize an administrative procedure established by Virginia law that permits the development of CBM by an operator in those instances where the owner of the CBM has not leased it to the operator or in situations where there are conflicting claims of ownership of the CBM within a drilling unit. The general practice is to "force pool" both the coal owner and the gas owner by filing an application with and obtaining an order from the Virginia Gas and Oil Board that permits the development of the CBM in the drilling unit notwithstanding lack of control of the CBM or conflicting claims of ownership. Any royalties otherwise payable to conflicting claimants are paid into escrow and the burden then is upon the conflicting claimants to establish ownership by court action. The Virginia Gas and Oil Board does not make ownership decisions. Several lawsuits are pending in Virginia state courts and several purported class action lawsuits are pending in the Federal District Court for the Western District of Virginia in Abingdon, Virginia, including two lawsuits to which a CONSOL Energy subsidiary is named as a defendant, which seek, among other things, a court order establishing ownership of the CBM relating to the royalties currently held in escrow.

West Virginia

The ownership of CBM is largely an open question in West Virginia. The West Virginia Supreme Court has held that under a conventional oil and gas lease executed prior to the inception of widespread public knowledge regarding CBM operations, the oil and gas lessee did not acquire the right to produce CBM. The West Virginia courts have not further clarified who owns CBM in West Virginia.

West Virginia has enacted the Coalbed Methane Wells and Units Act (the West Virginia Act), regulating the commercial recovery and marketing of CBM. Although the West Virginia Act does not specify who owns, or has the right to exploit, CBM in West Virginia and instead refers ownership disputes to judicial resolution, it contains provisions similar to Virginia's force pooling law described above. Under the pooling provisions of the West Virginia Act, an applicant who proposes to drill can prosecute an administrative proceeding with the West Virginia Coalbed Methane Review Board to obtain authority to produce CBM from pooled acreage. Owners and claimants of CBM interests who have not consented to the drilling are afforded certain elective forms of participation in the drilling (e.g., royalty or owner), but their consent is not required to obtain a pooling order authorizing the production of CBM by the operator within the boundaries of the drilling unit. The West Virginia Act also provides that, where title to subsurface minerals has been severed in such a way that title to coal and title to natural gas are vested in different persons, the operator of a CBM well permitted, drilled and completed under color of title to the CBM from either the coal seam owner or the natural gas owner has an affirmative defense to an action for willful trespass relating to the drilling and commercial production of CBM from that well.

Other States

We have rights to extract CBM where we have coal rights in other states. The ownership of CBM in the Illinois Basin and certain other western basins may be uncertain or could belong to other holders of real estate interests and we may need to acquire additional rights from other holders of real estate interests to extract and produce CBM in these other states

Available Information

CONSOL Energy maintains a website on the World Wide Web at www.consolenergy.com. CONSOL Energy makes available, free of charge, on this website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the 1934 Act), as soon as reasonably practicable after such reports are available, electronically filed with, or furnished to the SEC, and are also available at the SEC's website www.sec.gov.

Executive Officers of the Registrant

Incorporated by reference into this Part I is the information set forth in Part III, Item 10 under the caption “Directors and Executive Officers of CONSOL Energy” (included herein pursuant to Item 401 (b) of Regulation S-K).

ITEM 1A. Risk Factors

Investment in our securities is subject to various risks, including risks and uncertainties inherent in our business. The following sets forth factors related to our business, operations, financial position or future financial performance or cash flows which could cause an investment in our securities to decline and result in a loss.

Deterioration in the global economic conditions in any of the industries in which our customers operate, or sustained uncertainty in financial markets, may have adverse impacts on our business and financial condition that we currently cannot predict.

Economic conditions in a number of industries in which our customers operate, such as electric power generation and steel making, substantially deteriorated in recent years and reduced the demand for natural gas and coal. Although global industrial activity recovered in 2010 and 2011 from 2009 levels, it weakened in 2012 and the outlook is uncertain, especially for Europe which continues to be affected by sovereign debt issues and the United States which may significantly increase taxes and cut government spending to address deficits. In addition, in 2008 and 2009 financial markets in the United States, Europe and Asia also experienced unprecedented turmoil and upheaval. This was characterized by extreme volatility and declines in security prices, severely diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the United

States federal government and other governments. Although we cannot predict the impacts, renewed weakness in the economic conditions of any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

- demand for natural gas and electricity in the United States is impacted by industrial production, which if weakened would negatively impact the revenues, margins and profitability of our natural gas and thermal coal business;
- demand for metallurgical coal depends on steel demand in the United States and globally, which if weakened would negatively impact the revenues, margins and profitability of our metallurgical coal business including our ability to sell our high volatile steam coal as higher-priced metallurgical coal;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables and the amount of receivables eligible for sale pursuant to our accounts receivable securitization facility may decline;
- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business including for exploration and/or development of our coal or gas reserves; and
- our commodity hedging arrangements could become ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection.

An extended decline in demand for or the prices CONSOL Energy receives for coal and natural gas will adversely affect our operating results and cash flows.

Our financial results are significantly affected by the demand for and the prices we receive for our coal and natural gas.

Coal accounted for approximately 80% of our revenues in 2012. Prices of and demand for our coal may fluctuate due to factors beyond our control such as:

- overall domestic and global economic conditions, technological advances affecting energy consumption, price and availability of foreign coal, and domestic and foreign government regulations;
- the consumption pattern of industrial consumers, electricity generators and residential users as well as weather can impact thermal coal (for example, the unusually warm 2011 - 2012 winter left utilities with large coal stockpiles and depressed the demand for thermal coal);
- the price and availability of alternative fuels for electricity generation, especially natural gas (for example, abundant natural gas supplies at prices averaging less than $3/MMBtu during 2012 depressed the demand for thermal coal as natural gas fired electricity generation market share increased from approximately 27% in 2011 to 30% in 2012 and coal-fired generation declined from approximately 46% in 2011 to 37.5% in 2012); and
- increased utilization by the steel industry of electric arc furnaces or pulverized coal processes to make steel which do not use furnace coke, an intermediate product produced from metallurgical coal, decreases the demand for metallurgical coal.

Decreased demand and extended or substantial price declines for coal adversely affect our operating results for future periods and our ability to generate cash flows necessary to improve productivity and expand operations. For example, in 2012 domestic and global economic deterioration, unusually warm winter weather and abundant cheap natural gas decreased demand for our coal as well as decreased the average sales price for our metallurgical coal and resulted in our coal revenues and earnings before income taxes significantly declining from 2011.

Natural gas accounted for approximately 15% of our revenues in 2012. Natural gas prices are very volatile, and even relatively modest drops in prices can significantly affect our financial results and impede growth. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic supply of natural gas;
- the consumption pattern of industrial consumers, electricity generators and residential users and weather conditions;
- proximity and capacity of gas pipelines and other transportation facilities;
- overall domestic and global economic conditions;
- the price and availability of alternative fuels, especially thermal coal; and
- the price and supply of imported liquefied natural gas.

In particular, while demand for natural gas has recovered to pre-recession levels, the U.S. natural gas industry continues to face concerns of oversupply due to the success of new shale plays and continued drilling in these plays, despite lower gas prices, to meet drilling commitments. The oversupply of natural gas has resulted in prices hovering around ten year lows. Low gas prices adversely impacts our gas operations revenues and earnings before income taxes. For example, in 2012 as a result of low gas prices, our gas operations revenues and earnings before income taxes significantly declined from 2011.

An extended period of lower natural gas prices could negatively affect us in several other ways. These include reduced cash flow, which would decrease funds available for capital expenditures employed to replace reserves or increase production. For example, in light of the low natural gas prices during 2012, the number of wells drilled in our Noble joint venture during 2012 was significantly reduced from the number initially planned to be drilled. Also, our access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable. Additionally, lower natural gas prices may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our natural gas properties. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management's plans change with respect to those assets. We may incur impairment charges in the future, which could have an adverse effect on our results of operations in the period taken.

We and our joint venture partners have increased drilling activity in areas of shale formations which may also contain natural gas liquids and/or oil. The prices for natural gas liquids and oil are volatile for reasons similar to those described above regarding natural gas. Similar to the oversupply of natural gas, increased drilling activity in 2012 by third parties in formations containing natural gas liquids has led to a significant decline in the price of natural gas liquids. If we discover and produce significant amounts of natural gas liquids or oil, our results of operation may be adversely affected by downward fluctuations in natural gas liquids and oil prices

If coal customers do not extend existing contracts or do not enter into new long-term coal contracts, profitability of CONSOL Energy's operations could be affected.

During the year ended December 31, 2012, approximately 86% of the coal CONSOL Energy produced was sold under long-term contracts (contracts with terms of one year or more). If a substantial portion of CONSOL Energy's long-term contracts are modified or terminated or if force majeure is exercised, CONSOL Energy would be adversely affected if we are unable to replace the contracts or if new contracts are not at the same level of profitability. If existing customers do not honor current contract commitments, our revenue would be adversely affected. The profitability of our long-term coal supply contracts depends on a variety of factors, which vary from contract to contract and fluctuate during the contract term, including our production costs and other factors. Price changes, if any, provided in long-term supply contracts may not reflect our cost increases, and therefore, increases in our costs may reduce our profit margins. In addition, in periods of declining market prices, provisions in our long-term coal contracts for adjustment or renegotiation of prices and other provisions may increase our exposure to short-term coal price volatility. As a result, CONSOL Energy may not be able to obtain long-term agreements at favorable prices compared to either market conditions, as they may change from time to time, or our cost structure, and long-term contracts may not contribute to our profitability.

The loss of, or significant reduction in, purchases by our largest customers could adversely affect our revenues.

For the year ended December 31, 2012, we derived over 10% of our total revenues from sales to two coal customers individually and more than 35% of our total revenue from sales to our four largest coal and gas customers. At December 31, 2012, we had approximately twenty-seven coal supply agreements with these customers that expire at various times from 2013 to 2028. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and these customers may not continue to purchase coal from us under long-term coal supply agreements. If any one of these customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for coal and gas sold and delivered depends on the continued creditworthiness of our customers. Some power plant owners may have credit ratings that are below investment grade. If the creditworthiness of our customers declines significantly, our $200 million accounts receivable securitization program and our business could be adversely affected. In addition, if customers refuse to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customer's contractual obligations are honored.

The availability and reliability of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or impair our ability to supply coal to our customers. Similarly, our gas business depends on gathering, processing and transportation facilities owned by others and the disruption of, capacity constraints in, or proximity to pipeline systems could limit sales of our natural gas.

Coal producers depend upon rail, barge, trucking, overland conveyor and other systems to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lock-outs, break-downs of locks and dams or other events could temporarily impair our ability to supply coal to customers and adversely affect our profitability. Transportation costs represent a significant portion of the delivered cost of coal and, as a result, the cost of delivery is a critical factor in a customer's purchasing decision. Increases in transportation costs could make our coal less competitive.

We gather, process and transport our gas to market by utilizing pipelines and facilities owned by others. For example, we rely upon one gas processing facility located in Pennsylvania owned by MarkWest Energy Partners to process all of our gas which contains natural gas liquids. If pipeline or facility capacity is limited, or if pipeline or facility capacity is unexpectedly disrupted, our gas sales and/or sales of natural gas liquids could be limited, reducing our profitability. If we cannot access processing pipeline transportation facilities, we may have to reduce our production of gas or vent our produced gas to the atmosphere because we do not have facilities to store excess inventory. If our sales of gas or natural gas liquids are reduced because of transportation or processing constraints, our revenues will be reduced, and our unit costs will also increase. If pipeline quality tariffs change, we might be required to install additional processing equipment which could increase our costs. The pipeline could also curtail our flows until the gas delivered to their pipeline is in compliance.

Competition within the coal and natural gas industries may adversely affect our ability to sell our products. Increased competition or a loss of our competitive position could adversely affect our sales of, or our prices for, our coal and natural gas products, which could impair our profitability.

CONSOL Energy competes with coal producers in various regions of the United States and with some foreign coal producers for domestic sales primarily to electric power generators. CONSOL Energy also competes with both domestic and foreign coal producers for sales in international markets. Demand for our coal by our principal customers is affected by the delivered price of competing coals, other fuel supplies and alternative generating sources, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric and wind power. CONSOL Energy sells coal to foreign electricity generators and to the more specialized metallurgical coal market, both of which are significantly affected by international demand and competition. Increases in coal prices could encourage existing producers to expand capacity or could encourage new producers to enter the market. If overcapacity results, prices could fall or we may not be able to sell our coal, which would reduce revenue.

The gas industry is intensely competitive with companies from various regions of the United States. We compete with these companies and we may compete with foreign companies for domestic sales. Many of the companies we compete with are larger and have greater financial, technological, human and other resources. If we are unable to compete, our company, our operating results and financial position may be adversely affected. In addition, larger companies may be able to pay more to acquire new gas properties for future exploration, limiting our ability to replace natural gas we produce or to grow our production. Our ability to acquire additional properties and to discover new natural gas resources also depends on our ability to evaluate and select suitable properties and to consummate these transactions in a highly competitive environment.

We could be negatively affected if we fail to maintain satisfactory labor relations.

As of December 31, 2012, we had 8,896 employees. Approximately 31% of these employees are represented by the United Mine Workers of America (UMWA) and represented operations generated approximately 51% of our U.S. coal production during the year ended December 31, 2012. Relations with our employees and, where applicable, organized labor relations are important to our success. If we do not maintain satisfactory labor relations with our organized and non-represented employees, we may incur strikes, other work stoppages or have reduced productivity.

The characteristics of coal may make it costly for electric power generators and other coal users to comply with various environmental standards regarding the emissions of impurities released when coal is burned which could cause utilities to replace coal-fired power plants with alternative fuels. In addition, various incentives have been proposed to encourage the generation of electricity from renewable energy sources. A reduction in the use of coal for electric power generation could decrease the volume of our coal sales and adversely affect our results of operation.

Coal contains impurities, including sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air along with fine particulate matter and carbon dioxide when coal is burned. Complying with regulations on these emissions can be costly for electric power generators. For example, in order to meet the federal Clean Air Act limits for sulfur dioxide emissions from electric power plants, coal users will need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), or switch to other fuels. Each option has limitations. Lower sulfur coal may be more costly to purchase on an energy basis than higher sulfur coal depending on mining and transportation costs. The cost of installing scrubbers is significant and emission allowances may become more expensive as their availability declines. Switching to other fuels may require expensive modification of existing plants. Because higher sulfur coal currently accounts for a significant portion of our sales, the extent to which electric power generators switch to alternative fuel could materially affect us. Adoption of the Cross-State Air Pollution Rule (CASPR) in July 2011 (to be effective January 1, 2012, but currently subject to a stay) and the Mercury and Air Toxic Standards Rule (MATS) (remanded by the court and reproposed by EPA in November 2012) requiring reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, and particulate matter may require the installation of additional costly control technology or the implementation of other measures, including trading of emission allowances and switching to alternative fuels. These additional reductions in permissible emission levels of impurities by coal-fired plants will likely make it more costly to operate coal-fired electric power plants and may make coal a less attractive fuel alternative for electric power generation in the future. Another source of uncertainty is the consideration of regulation of coal ash disposal by EPA. In May 2010, EPA proposed new approaches for the regulation of Coal Combustion Residuals from electric generating facilities. EPA is re-evaluating its August 1993 and May 2000 Bevill determinations that currently provide exemptions for certain materials.

Apart from actual and potential regulation of emissions from coal-fired plants, state and federal mandates for increased use of electricity from renewable energy sources could have an impact on the market for our coal. Several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national standard although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reductions in the amount of coal consumed by domestic electric power generators as a result of current or new standards for the emission of impurities or incentives to switch to alternative fuels or renewable energy sources could reduce the demand for our coal, thereby reducing our revenues and adversely affecting our business and results of operations.

Regulation of greenhouse gas emissions as well as uncertainty concerning such regulation could adversely impact the market for coal and natural gas and the regulation of greenhouse gas emissions may increase our operating costs and reduce the value of our coal and gas assets.

While climate change legislation in the U.S. is unlikely in the next several years, the issue of global climate change continues to attract considerable public and scientific attention with widespread concern about the impacts of human activity, especially the emissions of greenhouse gases (GHGs), such as carbon dioxide and methane. Combustion of fossil fuels, such as the coal and gas we produce, results in the creation of carbon dioxide emissions into the atmosphere by coal and gas end users, such as coal-fired electric power generation plants. Numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government that are intended to limit emissions of GHGs. Several states have already adopted measures requiring reduction of GHGs within state boundaries. Internationally, the Kyoto Protocol, which set binding emission targets for developed countries (including the United States but has not been ratified by the United States, and Canada officially withdrew from its Kyoto commitment in 2012) was nominally extended past its expiration date of December 2012 with a requirement for a new legal construct to be put into place by 2015. Regulation of GHGs could occur in the United States pursuant to the Environmental Protection Agency (EPA) regulation under the Clean Air Act. On March 27, 2012, EPA proposed a Carbon Pollution Standard for New Power Plants that would, for the first time, set national limits on the amount of carbon pollution that new power plants can emit. On June 26, 2012 the US Court of Appeals for the District of Columbia rejected a legal challenge by a coalition of trade associations which questioned EPA's authority to regulate GHGs under the Clean Air Act. In July 2012, EPA issued its final greenhouse gas requirements for existing facilities emitting at least 100,000 tons/year of carbon dioxide equivalent (CO_2e) to obtain permits for Prevention of Significant Deterioration under the Clean Air Act. Apart from governmental regulation, on February 4, 2008, three of Wall Street's largest investment banks announced that they had adopted climate change guidelines for lenders. The guidelines require the evaluation of carbon risks in the financing of electric power generation plants which may make it more difficult for utilities to obtain financing for coal-fired plants.

If comprehensive legislation or regulation focusing on GHGs emission reductions is adopted for the United States or other countries where we sell coal, or if utilities were to have difficulty obtaining financing in connection with coal-fired plants, it may make it more costly to operate fossil fuel fired (especially coal-fired) electric power generation plants and make fossil fuels less attractive for electric utility power plants in the future. Depending on the nature of the regulation or legislation, natural gas-fueled power generation could become more economically attractive than coal-fueled power generation, substantially increasing the demand for natural gas. Apart from actual regulation, uncertainty over the regulation of GHG emissions may inhibit utilities from investing in the building of new coal-fired plants to replace older plants or investing in the upgrading of existing coal-fired plants. Any reduction in the amount of coal or possibly natural gas consumed by domestic electric power generators as a result of actual or potential regulation of greenhouse gas emissions could decrease demand for our fossil fuels, thereby reducing our revenues and materially and adversely affecting our business and results of operations. We or our customers may also have to invest in carbon dioxide capture and storage technologies in order to burn coal or natural gas and comply with future GHG emission standards.

In addition, coalbed methane must be expelled from our underground coal mines for mining safety reasons. Coalbed methane has a greater GHG effect than carbon dioxide. Our gas operations capture coalbed methane from our underground coal mines, although some coalbed methane is vented into the atmosphere when the coal is mined. If regulation of GHG emissions does not exempt the release of coalbed methane, we may have to further reduce our methane emissions, pay higher taxes, incur costs to purchase credits that permit us to continue operations as they now exist at our underground coal mines or perhaps curtail coal production. The amount of coalbed methane we emit is reported annually to the federal and state regulatory agencies, as well as in our annual Corporate Responsibility Report. We have recorded the amounts we have captured since the early 1990's.

Foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We compete in international markets against coal produced in other countries. Coal is sold internationally in U.S. dollars. As a result, mining costs in competing producing countries may be reduced in U.S. dollar terms based on currency exchange rates, providing an advantage to foreign coal producers. Currency fluctuations among countries purchasing and selling coal could adversely affect the competitiveness of our coal in international markets.

Our coal mining and natural gas operations are subject to operating risks, which could increase our operating expenses and decrease our production levels which could adversely affect our results of operations. Our coal and gas operations are also subject to hazards and any losses or liabilities we suffer from hazards which occur in our operations may not be fully covered by our insurance policies.

Our coal mining operations are predominantly underground mines. These mines are subject to a number of operating risks that could disrupt operations, decrease production and increase the cost of mining at particular mines for varying lengths of time thereby adversely affecting our operating results. In addition, if coal production declines, we may not be able to produce sufficient amounts of coal to deliver under our long-term coal contracts. CONSOL Energy's inability to satisfy contractual obligations could result in our customers initiating claims against us. The operating risks that may have a significant impact on our coal operations include:

- variations in thickness of the layer, or seam, of coal;
- amounts of rock and other natural materials intruding into the coal seam and other geological conditions that could affect the stability of the roof and the side walls of the mine;
- equipment failures or repairs;
- fires, explosions or other accidents;
- weather conditions; and
- security breaches or terroristic acts.

Our exploration for and production of natural gas also involves numerous operating risks. The cost of drilling, completing and operating our shale gas wells, shallow oil and gas wells and coalbed methane (CBM) wells is often uncertain, and a number of factors can delay or prevent drilling operations, decrease production and/or increase the cost of our gas operations at particular sites for varying lengths of time thereby adversely affecting our operating results. The operating risks that may have a significant impact on our gas operations include:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires, explosions or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;

- security breaches or terroristic acts;
- pipeline ruptures;
- lack of adequate capacity for treatment or disposal of waste water generated in drilling, completion and production operations;
- environmental contamination from surface spillage of fluids used in well drilling, completion or operation including fracturing fluids used in hydraulic fracturing of wells, or other contamination of groundwater or the environment resulting from our use of such fluids; and
- unavailability or high cost of drilling rigs, other field services and equipment.

Although we maintain insurance for a number of hazards, we may not be insured or fully insured against the losses or liabilities that could arise from a significant accident in our coal or gas operations.
A decrease in the availability or increase in the costs of commodities or capital equipment used in mining operations could decrease our coal production, impact our cost of coal production and decrease our anticipated profitability.

Coal mining consumes large quantities of commodities including steel, copper, rubber products and liquid fuels and requires the use of capital equipment. Some commodities, such as steel, are needed to comply with roof control plans required by regulation. The prices we pay for commodities and capital equipment are strongly impacted by the global market. A rapid or significant increase in the costs of commodities or capital equipment we use in our operations could impact our mining operations costs because we may have a limited ability to negotiate lower prices, and, in some cases, may not have a ready substitute.

We rely upon third party contractors to provide various field services to our coal and gas operations. A decrease in the availability of or 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 decrease our production, increase our costs of production, and decrease our anticipated profitability.

We rely upon third party contractors to provide key services to our gas operations. We contract with third parties for well services, related equipment, and qualified experienced field personnel to drill wells and conduct field operations. The demand for these field services in the natural gas and oil industry can fluctuate significantly. Higher oil and natural gas prices generally stimulate increased demand causing periodic shortages. These shortages may lead to escalating prices for drilling equipment, crews and associated supplies, equipment and services. Shortages may lead to poor service and inefficient drilling operations and increase the possibility of accidents due to the hiring of inexperienced personnel and overuse of equipment by contractors. In addition, the costs and delivery times of equipment and supplies are substantially greater in periods of peak demand. Accordingly, we cannot assure that we will be able to obtain necessary drilling equipment and supplies in a timely manner or on satisfactory terms, and we may experience shortages of, or increases in the costs of, drilling equipment, crews and associated supplies, equipment and field services in the future. We also use third party contractors to provide construction and specialized services to our mining operations. A decrease in the availability of field services or equipment and supplies, an increase in the prices charged for field services, equipment and supplies, or the failure of third party contractors to provide quality field services to us, could decrease our coal and gas production, increase our costs of coal and gas production, and decrease our anticipated profitability.

We attempt to mitigate the risks involved with increased industrial activity by entering into “take or pay” contracts with well service providers which commit them to provide field services to us at specified levels and commit us to pay for field services at specified levels even if we do not use those services. However, these contracts expose us to economic risk. For example, if the price of natural gas declines and it is not economical to drill and produce additional natural gas, we may have to pay for field services that we did not use. This would decrease our cash flow and raise our costs of production.

For mining and drilling operations, CONSOL Energy must obtain, maintain, and renew governmental permits and approvals which if we cannot obtain in a timely manner would reduce our production, cash flow and results of operations.

Most coal producers in the eastern U.S. are being impacted by government regulations and enforcement to a much greater extent than a few years ago, particularly in light of the renewed focus by environmental agencies and the government generally on the mining industry, including more stringent enforcement and interpretation of the laws that regulate mining. The pace with which the government issues permits needed for new operations and for on-going operations to continue mining has negatively impacted expected production, especially in Central Appalachia. Environmental groups in Southern West Virginia and Kentucky have challenged state and U.S. Army Corps of Engineers permits for mountaintop and types of surface mining operations on various grounds. The most recent challenges have focused on the adequacy of the U.S Army Corps of Engineers analysis of impacts to streams and the adequacy of mitigation plans to compensate for stream impacts resulting from valley fill permits required for mountaintop mining. These challenges have also enhanced the EPA's oversight and involvement in the review of permits by state regulatory authorities. In 2007, the U.S. District Court for the Southern District of West Virginia found other operators' permits for mining in these areas to be deficient. In February 2009, the U.S. Court of Appeals for the Fourth Circuit reversed that decision, finding that the permits were adequate. The EPA's objections and an enhanced review process that was being implemented under a federal multi-agency memorandum of understanding effectively held up the issuance of permits for all types of mining operations that require Clean Water Act Section 402 discharge permits and Section 404 dredge and fill permits, including surface facilities for underground mines. The EPA's enhanced review process was invalidated in October 2011, in part because the EPA failed to follow public notice and rulemaking requirements, and on July 31, 2012, the federal District Court for the District of Columbia struck down EPA's “guidance memorandum” for coal-related water permitting actions in which EPA recommended permits include limits on specific conductivity which currently neither EPA nor the states have a standard. However, normal permitting has not yet resumed. Also, the EPA may elect to seek to adopt regulations to codify its enhanced review process. CONSOL Energy's surface and underground operations have been impacted to a limited extent to date, but a permit for a new mine was impacted which resulted in the issuance of a Worker Adjustment and Retraining Notification (WARN) which affected some 145 employees on October 30, 2012. CONSOL Energy was able, in this instance, to redeploy these employees to work at another adjacent coal mine property for which a permit was already issued. However, there is no assurance that the permit for the new coal mine will be issued, or that CONSOL Energy would be able to re-deploy its employees under future similar circumstances. In addition, the length of time needed to bring a new mine into production has increased by several years because of the increased time required to obtain necessary permits. These delays or denials of mining permits could reduce our production, cash flow and results of operations.

Existing and future government laws, regulations and other legal requirements relating to protection of the environment, and others that govern our business may increase our costs of doing business for coal and may restrict our coal operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local, as well as foreign authorities relating to protection of the environment. These include those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and wastes, the cleanup of contaminated sites, groundwater quality and availability, threatened and endangered plant and wildlife protection, reclamation and restoration of mining or drilling properties after mining or drilling is completed, the installation of various safety equipment in our mines, remediation of impacts of surface subsidence from underground mining, and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant affect on our costs of operations and competitive position. For example, we have agreed to commence operation by May 30, 2013, of a new advanced waste water treatment plant to treat the discharge of mine water from our Blacksville #2, Loveridge and Robinson Run mines at a total estimated cost of approximately $200 million. In addition, there is the possibility that we could incur substantial costs as a result of violations under environmental laws. Any additional laws, regulations and other legal requirements enacted or adopted by federal, state and local, as well as foreign authorities or new interpretations of existing legal requirements by regulatory bodies relating to the protection of the environment matters could further affect our costs of operations and competitive position. The Clean Water Act is being used by opponents of mountain top removal mining as a means to challenge permits. In addition, CONSOL Energy incurs and will continue to incur costs associated with the investigation and remediation of environmental contamination under the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) and similar state statutes and has been named as a potentially responsible party at Superfund sites in the past.

Existing and future government laws, regulations and other legal requirements relating to protection of the environment, and others that govern our business may increase our costs of doing business for natural gas, and may restrict both our gas operations.

State and local authorities regulate various aspects of gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, market sharing and well site restoration.

Additionally, regulations applicable to the gas industry are under constant review for amendment or expansion at the federal and state level. Any future changes may affect, among other things, the pricing or marketing of gas production. For example, hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as Marcellus Shale. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. Hydraulic fracturing is currently exempt from regulation under the federal Safe

Drinking Water Act, except for hydraulic fracturing using diesel fuel. The disposal of produced water, drilling fluids and other wastes in underground injection disposal wells is regulated by the EPA under the federal Safe Drinking Water Act or by the states under counterpart state laws and regulations. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing operations or to dispose of waste resulting from such operations. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities with a final report to be issued in 2014. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy (DOE), the U.S. Government Accountability Office and the Department of the Interior. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances. If hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs.

Additionally, some states have begun to adopt more stringent regulation and oversight of natural gas gathering lines than is currently required by federal standards. Pennsylvania, under Act 127, authorized the Public Utility Commission oversight of Class I gathering lines, as well as requiring standards and fees associated with Class II and Class III pipelines. The state of Ohio also moved to regulate natural gas gathering lines in a similar manner pursuant to Ohio Senate Bill 315 (SB315). SB315 expanded the PUC's authority over rural natural gas gathering lines. These changes in interpretation and regulation affect CONSOL Energy's midstream activities, requiring changes in reporting as well as increased costs.

Further, some state and local governments in the Marcellus Shale region in Pennsylvania and New York have considered or imposed a temporary moratorium on drilling operations using hydraulic fracturing until further study of the potential for environmental and human health impacts by the EPA or the relevant agencies are completed. No assurance can be given as to whether or not similar measures might be considered or implemented in other jurisdictions in which our gas properties are located. If new laws or regulations that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in states in which we operate, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. New laws or regulations could also cause delays or interruptions or terminations of operations, the extent of which cannot be predicted, and could reduce the amount of oil and natural gas that we ultimately are able to produce in commercially paying quantities from our gas properties, all of which could have a material adverse affect on our results of operation and financial condition.

Our shale gas drilling and production operations require both adequate sources of water to use in the fracturing process as well as the ability to dispose of water and other wastes after hydraulic fracturing. Our CBM gas drilling and production operations also require the removal and disposal of water from the coal seams from which we produce gas. If we cannot find adequate sources of water for our use or are unable to dispose of the water we use or remove it from the strata at a reasonable cost and within applicable environmental rules, our ability to produce gas economically and in commercial quantities could be impaired.

As part of our drilling and production in the Marcellus Shale, we use hydraulic fracturing processes. Thus, we need access to adequate sources of water to use in our Marcellus Shale operations. Further, we must remove and dispose of the portion of the water that we use to fracture our shale gas wells that flows back to the well-bore as well as drilling fluids and other wastes associated with the exploration, development or production of natural gas. In addition, in our CBM drilling and production, coal seams frequently contain water that must be removed and disposed of in order for the gas to detach from the coal and flow to the well bore. Our inability to locate sufficient amounts of water with respect to our Marcellus Shale operations, or the inability to dispose of or recycle water and other wastes used in our Marcellus Shale and our CBM operations, could adversely impact our operations. For example, in Ohio, injection of gas well production fluids was temporarily suspended for underground injection disposal wells near Youngstown while regulatory authorities investigated whether injection of wastewater into the wells was causing low category earthquakes in the area.

Our mines are subject to stringent federal and state safety regulations that increase our cost of doing business at active operations and may place restrictions on our methods of operation. In addition, government inspectors under certain circumstances, have the ability to order our operations to be shut down based on safety considerations. A mine could be shut down for an extended period of time if a disaster were to occur at it.

Stringent health and safety standards were imposed by federal legislation when the Federal Coal Mine Health and Safety Act of 1969 was adopted. The Federal Coal Mine Safety and Health Act of 1977 expanded the enforcement of safety and health standards of the Coal Mine Health and Safety Act of 1969 and imposed safety and health standards on all (non-coal as well as coal) mining operations. Regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, the equipment used in mine emergency procedures, mine plans and other matters. The additional requirements of the Mine Improvement and New Emergency Response Act of 2006 (the Miner Act) and implementing federal regulations include, among other things, expanded emergency response plans, providing additional quantities of breathable air for emergencies, installation of refuge chambers in underground coal mines, installation of two-way communications and tracking systems for underground coal mines, new standards for sealing mined out areas of underground coal mines, more available mine rescue teams and enhanced training for emergencies. Most states in which CONSOL Energy operates have programs for mine safety and health regulation and enforcement. We believe that the combination of federal and state safety and health regulations in the coal mining industry is, perhaps, the most comprehensive system for protection of employee safety and health affecting any industry. Most aspects of mine operations, particularly underground mine operations, are subject to extensive regulation. The various requirements mandated by law or regulation can place restrictions on our methods of operations, creating a significant effect on operating costs and productivity. In addition, government inspectors under certain circumstances, have the ability to order our operation to be shut down based on safety considerations. If a disaster were to occur at one of our mines, it could be shut down for an extended period of time and our reputation with our customers could be materially damaged.

Our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in liabilities to us.

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as “acid mine drainage.” We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or for the entire share.

We maintain extensive coal refuse areas and slurry impoundments at a number of our mining complexes. Such areas and impoundments are subject to extensive regulation. Our coal refuse areas and slurry impoundments are designed, constructed, and inspected by our company and by regulatory authorities according to stringent environmental and safety standards. Structural failure of a slurry impoundment or coal refuse area could result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages, and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure. If one of our impoundments were to fail, we could be subject to claims for the resulting environmental contamination and associated liability, as well as for fines and penalties.

In West Virginia there are areas where drainage from coal mining operations contains concentrations of selenium that without treatment would result in violations of state water quality standards that are set to protect fish and other aquatic life. CONSOL Energy has two operations with selenium discharges. CONSOL Energy and other coal companies are working to expeditiously develop cost effective means to remove selenium from mine water. If such technology or processes are not developed promptly, the only available effective treatment technologies are expensive to construct and operate which will increase coal production costs.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could adversely affect us. An example of this is Naturally Occurring Radioactive Material (NORM) or Technologically-Enhanced, Naturally Occurring Radioactive Material (TENORM). NORM or TENORM is produced when activities such as sewage sludge treatment or deep drilling concentrate or expose radioactive materials that occur naturally in ores, soils, water, or other natural materials. State and federal agencies are examining the possibility for worker exposure or associated environmental hazards due to processing and disposal of wastes. CONSOL Energy's operations could be affected if there is a hazard associated with NORM/TENORM or if it were to be regulated in such a way as to require expensive treatment and disposal options.

CONSOL Energy has reclamation, mine closing and gas well plugging obligations. If the assumptions underlying our accruals are inaccurate, we could be required to expend greater amounts than anticipated.

The Surface Mining Control and Reclamation Act establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Also, state laws require us to plug gas wells and reclaim well sites after the useful life of our gas wells has ended. CONSOL Energy accrues for the costs of current mine disturbance, gas well plugging and of final mine closure, including the cost of treating mine water discharge where necessary. Estimates of our total reclamation, mine-closing liabilities and gas well plugging, which are based upon permit requirements and our experience, were approximately $699 million at December 31, 2012. The amounts recorded are dependent upon a number of variables, including the estimated future closure costs, estimated proven reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rates. Furthermore, these obligations are unfunded. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be adversely affected.

Most states where we operate require us to post bonds for the full cost of coal mine reclamation (full cost bonding). West Virginia is not a full cost bonding state. West Virginia has an alternative bond system (ABS) for coal mine reclamation which consists of (i) individual site bonds posted by the permittee that are less than the full estimated reclamation cost plus (ii) a bond pool (Special Reclamation Fund) funded by a per ton fee on coal mined in the State which is used to supplement the site specific bonds if needed in the event of bond forfeiture. The Special Reclamation Fund is currently underfunded, and the adequacy of the fund became subject to a citizen suit before the U.S. District Court in West Virginia. In an effort to settle the issue in 2012, the WV legislature authorized an increase in the per ton fee levied on coal production to make up the shortfall. There remains the possibility that WV may move to full cost bonding in the future which could cause individual mining companies and/or surety companies to exceed bonding capacity and would result in the need to post cash bonds or letters of credit which would reduce operating capital. Pennsylvania has begun to enforce full cost bonding for new capital projects, further increasing the amount of surety bonds CONSOL Energy must seek in order to permit its mining activities.

CONSOL Energy faces uncertainties in estimating our economically recoverable coal and gas reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

There are uncertainties inherent in estimating quantities and values of economically recoverable coal reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Some of the factors and assumptions which impact economically recoverable coal reserve estimates include:

- geological conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- assumptions governing future prices; and
- future operating costs, including the cost of materials.

In addition, we hold substantial coal reserves in areas containing Marcellus Shale and other shales. These areas are currently the subject of substantial exploration for oil and gas, particularly by horizontal drilling. If a well is in the path of our mining for coal, we may not be able to mine through the well unless we purchase it. Although in the past we have purchased vertical wells, the cost of purchasing a producing horizontal well could be substantially greater. Horizontal wells with multiple laterals extending from the well pad may access larger oil and gas reserves than a vertical well which could result in higher costs. In future years, the cost associated with purchasing oil and gas wells which are in the path of our coal mining may make mining through those wells uneconomical thereby effectively causing a loss of significant portions of our coal reserves.

Similarly, natural gas reserves require subjective estimates of underground accumulations of natural gas and assumptions concerning natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved gas reserves and projections of future production rates and the timing of development expenditures may be incorrect. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, testing and production. Also, we make certain assumptions regarding natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our gas reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of gas reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of gas we ultimately recover being different from reserve estimates. The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our proved gas reserves on historical average prices and costs. However, actual future net cash flows from our gas and oil properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;
- the amount and timing of actual production;
- assumptions governing future prices;
- future operating costs; and

• capital costs of drilling new wells.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. In addition, if natural gas prices decline by $0.10 per thousand cubic feet, then the pre-tax present value using a 10% discount rate of our proved gas reserves as of December 31, 2012 would decrease from $1.2 billion to $1.1 billion. The standardized Generally Accepted Accounting Principle measure associated with this decline of $0.10 per thousand cubic feet, would be approximately $650 million.

Each of the factors which impacts reserve estimation may in fact vary considerably from the assumptions used in estimating the reserves. For these reasons, estimates of coal and gas reserves may vary substantially. Actual production, revenues and expenditures with respect to our coal and gas reserves will likely vary from estimates, and these variances may be material. As a result, our estimates may not accurately reflect our actual coal and gas reserves.

Defects may exist in our chain of title for our coal estate and we have not done a thorough chain of title examination of our gas estate. We may incur additional costs and delays to produce coal and gas because we have to acquire additional property rights to perfect our title to coal or gas rights. If we fail to acquire additional property rights to perfect our title to coal or gas rights, we may have to reduce our estimated reserves.

While chain of title for our coal estate generally has been established, there may be defects in it that we do not realize until we have committed to developing those properties or coal reserves. As such, the title to the coal estate that we intend to mine may contain defects. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs perfecting title. If we cannot cure these defects, we may have to reduce our coal reserves.

Substantial amounts of acreage in which we believe we control gas rights are in areas where we have not yet done a thorough chain of title examination of the gas estate. A number of our gas properties were acquired primarily for the coal rights with the focus on the coal estate title, and, in many cases were acquired years ago. In addition, we have acquired gas rights in substantial acreage from third parties who had not performed thorough chain of title work on their gas properties. Our practice, and we believe industry practice, is not to perform a thorough title examination on gas properties until shortly before the commencement of drilling activities at which time we seek to acquire any additional rights needed to perfect our ownership of the gas estate for development and production purposes. When we perform a thorough chain of title examination, we may discover material defects in our title which would require us to acquire additional property rights. We may incur substantial costs to acquire these additional property rights. In addition, the acquisition of the necessary rights may not be feasible in some cases. Our discovering title defects which we are unable to cure may adversely impact our ability to develop those properties and we may have to reduce our estimated gas reserves including our proved undeveloped reserves.

Some states (West Virginia and Virginia) permit us to produce coalbed methane gas without perfected ownership under an administrative process known as “pooling,” which require us to give notice to all potential claimants and pay royalties into escrow until the undetermined rights are resolved. As a result, we may have to pay royalties to produce coalbed methane gas on acreage that we control and these costs may be material. Further, the pooling process is time-consuming and may delay our drilling program in the affected areas.

In confirming title to the gas estate in Pennsylvania, we rely upon long standing Pennsylvania Supreme Court decisions. A recent decision by the intermediate appellate court in Pennsylvania in a case captioned Butler v. Powers (Pa. Superior Ct., No. 1795 MDA 2010) did not change the law of Pennsylvania, but in remanding the case to the trial court for further proceedings, it called into question the applicability of a long-standing presumption known as the Dunham Rule to gas in the Marcellus Shale. The Dunham Rule is a presumption that a reservation or conveyance of minerals does not transfer the ownership of oil and gas absent an express reference to oil and gas. While we believe that the Pennsylvania courts will ultimately confirm that the Dunham Rule applies to Marcellus Shale gas, if the Pennsylvania courts were to hold otherwise, we could be exposed to lawsuits challenging our rights to Marcellus Shale gas in some of our Pennsylvania properties where our rights derive from persons who did not also own the mineral rights and we may have to incur substantial additional costs to perfect our gas title in those Pennsylvania properties.

Our subsidiaries, primarily Fairmont Supply Company, are co-defendants in various asbestos litigation cases which could result in making payments in the future that are material.

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. Past payments by Fairmont with respect to asbestos cases have not been material, however, it is reasonably possible that payments in the future with respect to pending or future asbestos cases may be material to the financial position, results of operations or cash flows of CONSOL Energy.
CONSOL Energy and its subsidiaries are subject to various legal proceedings, which may have an adverse effect on our business.

We are party to a number of legal proceedings in the normal course of business activities. Defending these actions, especially purported class actions, can be costly, and can distract management. For example, we are a defendant in five pending purported class action lawsuits dealing with such diverse matters as the propriety of our acquisition of the noncontrolling interest of CNX Gas, our right to natural gas production in some areas, and asserting that we are responsible for Hurricane Katrina and the damage it caused. There is the potential that the costs of defending litigation in an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position. See Note 23-Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion of pending legal proceedings.

CONSOL Energy has obligations for long-term employee benefits for which we accrue based upon assumptions which, if inaccurate, could result in CONSOL Energy being required to expense greater amounts than anticipated.

CONSOL Energy provides various long-term employee benefits to inactive and retired employees. We accrue amounts for these obligations. At December 31, 2012, the current and non-current portions of these obligations included:

- postretirement medical and life insurance ($3.0 billion);
- coal workers' black lung benefits ($184.1 million);
- salaried retirement benefits ($224.9 million); and
- workers' compensation ($179.6 million).

However, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. Salary retirement benefits are funded in accordance with Employer Retirement Income Security Act of 1974 (ERISA) regulations. The other obligations are unfunded. In addition, the federal government and several states in which we operate consider changes in workers' compensation and black lung laws from time to time. Such changes, if enacted, could increase our benefit expense.

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.

Certain of our subsidiaries have been contributing to a multi-employer defined benefit pension plan (1974 Pension Trust) for United Mine Workers of America (UMWA) retirees under the terms of various National Bituminous Coal

Wage Agreements (NBCWA) which those subsidiaries have entered into over the years with the UMWA. The current NBCWA with the UMWA became effective July 1, 2011 and expires on December 31, 2016. All assets contributed to the 1974 Pension Trust are pooled and available to provide benefits for all participants and beneficiaries. As a result, contributions made by our signatory subsidiaries benefit employees of CONSOL Energy and of other employers. For the plan year ended June 30, 2012, approximately 18% of retirees and surviving spouses receiving benefits from the 1974 Pension Trust last worked at signatory subsidiaries of CONSOL Energy. The 1974 Pension Trust is overseen by a board of trustees, consisting of two union-appointed trustees and two employer-appointed trustees. The trustees' responsibilities include selection of the plan's investment policy, asset allocation, individual investment of plan assets and the administration of the plan. The benefits provided by the 1974 Pension Trust to the participating employees are determined based on age and years of service at retirement. The current NBCWA calls for contribution amounts to be paid to the 1974 Pension Trust by our signatory subsidiaries during the term of the NBCWA based principally on hours worked by our UMWA-represented employees at a contribution rate of $5.50 per hour.

As of June 30, 2012, the most recent date for which information is available, the 1974 Pension Trust was underfunded. This determination was made in accordance with Employer Retirement Income Security Act of 1974 (ERISA) calculations, with a total actuarial asset value of $4.7 billion and a total actuarial accrued liability of $6.4 billion. Under the Pension Protection Act of 2006 (Pension Protection Act), a funded percentage of 80% should be maintained for this multi-employer pension plan, and if the plan is determined to have a funded percentage of less than 80% it will be deemed to be “endangered” or “seriously endangered” if the number of years to reach a projected funding deficiency equals seven or less, and if less than 65%, it will be deemed to be in “critical” status. The funded percentage certified by the actuary for the 1974 Pension Trust was determined to be approximately 72.6% under the Pension Act. On October 26, 2012, the signatory subsidiaries of CONSOL Energy received notice from the trustees of the 1974 Pension Trust stating that the 1974 Pension Plan is considered to be in “seriously endangered” status for the plan year beginning July 1, 2012 due to the funded percentage and projected funding deficiency. As required by the Pension Protection Act, the 1974 Pension Trust adopted a funding improvement plan on May 25, 2012. Because the 2011 NBCWA established our signatory subsidiaries contribution obligations through December 31, 2016, our signatory subsidiaries' contributions to the 1974 Pension Trust should not increase during the term of the NBCWA as a consequence of any funding improvement plan adopted by the 1974 Pension Trust to address the plan's seriously endangered status.

Upon expiration of the 2011 NBCWA, our signatory subsidiaries could be required to increase contributions to the 1974 Pension Trust in amounts that could be material to our financial position and results of operations or cash flows. In the event our subsidiaries were to withdraw from the 1974 Pension Trust, CONSOL Energy and its subsidiaries would be liable for a proportionate share of such pension plan's unfunded vested benefits, as determined by the plan's actuary. Based on the information available from the 1974 Pension Trust's administrators, we believe that our portion of the contingent liability represented by the plan's unfunded vested benefits, in the case of the withdrawal of our signatory subsidiaries from the plan or in the case of the termination of the plan, would be material to our financial position and results of operations. As of June 30, 2012 in the event certain of our subsidiaries were to withdraw from the 1974 Pension Trust they would have the option to pay the amount of any withdrawal liability assessed by the 1974 Pension Trust in collective annual installments of approximately $35 to $40 million per year. In the event that any other contributing employer withdraws from the 1974 Pension Trust and such employer (or any member in its controlled group) cannot satisfy their obligations under the plan at the time of withdrawal, then we, along with the other remaining contributing employers, would be liable for an increase in our proportionate share of the 1974 Pension Trust's unfunded vested benefits at the time of the withdrawal from the plan or its termination.

If lump sum payments made to retiring salaried employees pursuant to CONSOL Energy's defined benefit pension plan exceed the total of the service cost and the interest cost in a plan year, CONSOL Energy would need to make an adjustment to operating results equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum payment in that year, which may result in an adjustment that could reduce operating results.

CONSOL Energy's defined benefit pension plan for salaried employees allows such employees to receive a lump-sum distribution for benefits earned up through December 31, 2005 in lieu of annual payments when they retire from CONSOL Energy. Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans for Terminations Benefits requires that if the lump-sum distributions made for a plan year exceed the total of the service cost and interest cost for the plan year, CONSOL Energy would need to recognize for that year's results of operations an adjustment equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum in that year. This type of adjustment may result in a reduction in operating results.

Acquisitions that we have completed, acquisitions that we may undertake in the future, as well as expanding existing company mines, involve a number of risks, any of which could cause us not to realize the anticipated benefits and to the extent we plan to engage in joint ventures and divestitures, we do not control the timing of these and they may not provide anticipated benefits.

We have completed several acquisitions and investments in the past including the approximately $3.5 billion Dominion Acquisition, which closed on April 30, 2010. We also continually seek to grow our business by adding and developing coal and gas reserves through acquisitions and by expanding the production at existing mines and existing gas operations. If we are unable to successfully integrate the companies, businesses or properties we acquire, we may fail to realize the expected benefits of the acquisition and our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Acquisitions, mine expansion and gas operation expansion involve various inherent risks, including:

- uncertainties in assessing the value, strengths, and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental liabilities) of expansion and acquisition opportunities;

- the potential loss of key customers, management and employees of an acquired business;
- the ability to achieve identified operating and financial synergies anticipated to result from an expansion or an acquisition opportunity;
- the potential revision of assumptions regarding gas reserves as we acquire more knowledge by operating an acquired gas business;
- problems that could arise from the integration of the acquired business;
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion or the acquisition opportunity; and
- we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions.

From time to time part of our business and financing plans include entering into joint venture arrangements and the divestiture of certain assets. However, we do not control the timing of divestitures or joint venture arrangements and delays in entering into divestitures or joint venture arrangements may reduce the benefits from them. In addition, the terms of divestitures and joint venture arrangements may make a substantial portion of the benefits we anticipate receiving from them to be subject to future matters that we do not control.

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 our joint venture agreements with Noble Energy and Hess, each of them has the right to perform due diligence on the title to the oil and gas interests which we conveyed to them and to assert that title to the acreage is defective. CONSOL Energy then can review and respond to the asserted title defects, or cure them, and ultimately, if the claim is not resolved, either party can submit the defect to an arbitrator for resolution. CONSOL Energy also has the right to require the defected acreage to be reassigned in certain circumstances. We are currently engaged in this title review process with Noble and Hess. If they establish any title defects which are not resolved in favor of CONSOL Energy or if the subject acreage is reassigned to us at our request, then subject to certain deductibles, Noble's and Hess's respective aggregate carried cost obligation under the joint venture agreements will be reduced by the value the parties previously allocated to the affected acreage in the transaction. 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. To date, Noble has asserted formal title defects with respect to approximately 30,171 gross deal acres, which have an aggregate transaction value of $196 million. We believe that we will resolve most of those defects favorably to CONSOL Energy. To date, we have conceded defects to Noble which have an aggregate value equal to less than the applicable deductibles and the impact of these conceded defects on the Company's financial statements has not been material. In the case of our Ohio Utica Shale joint venture with Hess, based on title work performed by Hess, we believe that there are chain of title issues with respect to approximately 36,000 of the joint venture acres, most of which likely cannot be cured. Hess's 50% interest in these 36,000 acres has an allocated transaction value of approximately $146 million and may result in a corresponding reduction of the associated carried interest. The loss of these Utica Shale acres itself will not have a material impact on the Company's financial statements. After accounting for these defective acres, there are approximately 161,000 acres in our Ohio Utica Shale joint venture with Hess.

We may also enter into other joint venture arrangements in the future which could pose risks similar to risks described above.

CONSOL Energy's rights plan may have anti-takeover effects that may discourage a change of control even if doing so might be beneficial to our stockholders.

On December 19, 2003, CONSOL Energy adopted a rights plan which, in certain circumstances, including a person or group acquiring, or the commencement of a tender or exchange offer that would result in a person or group acquiring, beneficial ownership of more than 15% of the outstanding shares of CONSOL Energy common stock, would entitle each right holder to receive, upon exercise of the right, shares of CONSOL Energy common stock having a value equal to twice the right exercise price. For example, at an exercise price of $80 per right, each right not otherwise voided would entitle its holders to purchase $160 worth of shares of CONSOL Energy common stock for $80. Assuming that shares of CONSOL Energy common stock had a per share value of $16 at such time, the holder of each right would be entitled to purchase ten shares of CONSOL Energy common stock for $80, or a price of $8 per share, one half of its then market price. This and other provisions of CONSOL Energy's rights plan could make it more difficult for a third party to acquire CONSOL Energy, which could hinder stockholders' ability to receive a premium for CONSOL Energy stock over the prevailing market prices. The rights plan will expire on December 22, 2013.

The provisions of our debt agreements and the risks associated with our debt could adversely affect our business, financial condition and results of operations.

As of December 31, 2012, our total indebtedness was approximately $3.251 billion of which approximately $1.5 billion was under our 8.00% senior unsecured notes due April 2017, $1.25 billion was under our 8.25% senior unsecured notes due April 2020, $250 million was under our 6.375% senior notes due 2021, $103 million was under our Maryland Economic Development Corporation Port Facilities Refunding Revenue Bonds (MEDCO) 5.75% revenue bonds due September 2025, $59 million of capitalized leases due through 2021, $51 million of miscellaneous debt and $38 million due under the accounts receivable securitization facility. The degree to which we are leveraged could have important consequences, including, but not limited to:

- increasing our vulnerability to general adverse economic and industry conditions;

- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions, development of our coal and gas reserves or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal and gas industries; and
- placing us at a competitive disadvantage compared to less leveraged competitors.

Our senior secured credit facility and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes limit the incurrence of additional indebtedness unless specified tests or exceptions are met. In addition, our senior secured credit agreement and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes subject us to financial and/or other restrictive covenants. Under our senior secured credit agreement, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio, a maximum leverage ratio, and a maximum senior secured leverage ratio, as defined. Our senior secured credit agreement and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes impose a number of restrictions upon us, such as restrictions on granting liens on our assets, making investments, paying dividends, selling assets and engaging in acquisitions. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have an adverse effect on us.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our senior secured credit agreement and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes restrict our ability to sell assets and use the proceeds from the sales. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

Unless we replace our gas reserves, our gas reserves and production will decline, which would adversely affect our business, financial condition, results of operations and cash flows.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2012, production is expected to decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To manage our exposure to fluctuations in the price of natural gas, we enter into hedging arrangements with respect to a portion of our expected production. As of December 31, 2012, we had hedges on approximately 69.1 billion cubic feet of our 2013 natural gas production, 58.8 billion cubic feet of our 2014 natural gas production, and 40.6 billion cubic feet of our 2015 natural gas production. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges. If we choose not to engage in, or reduce our use of hedging arrangements in the future, we may be more adversely affected by changes in natural gas prices than our competitors who engage in hedging arrangements to a greater extent than we do.

In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our contracts fail to perform the contracts; or
- the creditworthiness of our counterparties or their guarantors is substantially impaired.

If our gas hedges would no longer qualify for hedge accounting, we will be required to mark them to market and recognize the adjustments through current year earnings. This may result in more volatility in our income in future periods.

Changes in federal or state income tax laws, particularly in the area of percentage depletion and intangible drilling costs, could cause our financial position and profitability to deteriorate.

The federal government has been reviewing the income tax laws relating to the coal and oil and gas industries regarding among other matters eliminating or changing certain U.S. federal income tax benefits currently available to coal mining and oil and gas exploration and development companies. Among the possible changes are eliminating the percentage depletion allowance and the intangible drilling costs deduction. It is unclear whether any such changes will be enacted or how soon such changes could be effective. If the percentage depletion allowance or the intangible drilling cost deduction were reduced or eliminated, any such change could negatively affect our financial condition and results of operations.

In February 2012, the state legislature of Pennsylvania passed a new natural gas impact fee in Pennsylvania, where a substantial portion of our acreage in the Marcellus Shale is located. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. The fee is on a sliding scale set by the Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average New York Mercantile Exchange's natural gas prices from the last day of each month. The estimated total fees per well based on today's current natural gas price is $310 thousand over the 15 year period. The passage of this legislation increases the financial burden on our operations in the Marcellus Shale.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

See “Coal Operations” and “Gas Operations” in Item 1 of this 10-K for a description of CONSOL Energy's properties.

ITEM 3. Legal Proceedings

The first through the nineteenth paragraphs of Note 23–Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K are incorporated herein by reference.

ITEM 4. Mine Safety and Health Administration Safety Data

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 is included in Exhibit 95 to this annual report.

PART II

ITEM 5. Market for Registrant's Common Equity and Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange under the symbol CNX. The following table sets forth for the periods indicated the range of high and low sales prices per share of our common stock as reported on the New York Stock Exchange and the cash dividends declared on the common stock for the periods indicated:

	High	Low	Dividends
Year Period Ended December 31, 2012			
Quarter Ended March 31, 2012	$39.37	$31.72	$0.125
Quarter Ended June 30, 2012	$35.15	$26.80	$0.125
Quarter Ended September 30, 2012	$33.79	$27.83	$0.125

Quarter Ended December 31, 2012	$36.60	$29.71	$0.250
Year Period Ended December 31, 2011			
Quarter Ended March 31, 2011	$55.49	$45.49	$0.100
Quarter Ended June 30, 2011	$54.17	$45.86	$0.100
Quarter Ended September 30, 2011	$54.82	$33.93	$0.100
Quarter Ended December 31, 2011	$46.75	$31.70	$0.125

As of December 31, 2012, there were 165 holders of record of our common stock.
The following performance graph compares the yearly percentage change in the cumulative total shareholder return on the common stock of CONSOL Energy to the cumulative shareholder return for the same period of a peer group and the Standard & Poor's 500 Stock Index. The peer group is comprised of CONSOL Energy, Alpha Natural Resources Inc., Anadarko Petroleum Corp., Apache Corp., Arch Coal Inc., Chesapeake Energy Corp., Devon Energy Corp., EOG Resources Inc., Newfield Exploration Co., Noble Energy Inc., Peabody Energy Corp., Plains Exploration & Production Company, Southwestern Energy, Co., QEP Resource Inc., and WPX Energy Inc. The graph assumes that the value of the investment in CONSOL Energy common stock and each index was $100 at December 31, 2007. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2012.

	2007	2008	2009	2010	2011	2012
CONSOL Energy Inc.	100.0	40.5	71.1	70.2	53.5	47.7
Peer Group	100.0	60.3	89.5	101.9	85.3	80.1
S&P 500 Stock Index	100.0	63.4	79.8	91.7	91.7	104.0

Cumulative Total Shareholder Return Among CONSOL Energy Inc., Peer Group and S&P 500 Stock Index
The above information is being furnished pursuant to Regulation S-K, Item 201 (e) (Performance Graph).
On December 10, 2012, CONSOL Energy's board of directors accelerated the declaration and payment of the regular quarterly dividend of $0.125 per share, payable on December 28, 2012, to shareholders of record on December 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 $0.40 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 2.50 to 1.00 and our availability was approximately $1.4 billion at December 31, 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 $0.40 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 year ended December 31, 2012 or restrictive conditions as stated in the various indentures thereby permitting dividends in excess of $0.40 per share annually to be paid in 2012.

See Part III, Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” for information relating to CONSOL Energy's equity compensation plans.

ITEM 6. Selected Financial Data

The following table presents our selected consolidated financial and operating data for, and as of the end of, each of the periods indicated. The selected consolidated financial data for, and as of the end of, each of the years ended December 31, 2012, 2011, 2010, 2009 and 2008 are derived from our audited Consolidated Financial Statements. Certain reclassifications of prior year data have been made to conform to the year ended December 31, 2012 presentation. The selected consolidated financial and operating data are not necessarily indicative of the results that may be expected for any future period. The selected consolidated financial and operating data should be read in conjunction with “Management's Discussion and Analysis of Financial Condition and Results of Operations” and the financial statements and related notes included in this Annual Report.

STATEMENT OF INCOME DATA
(In thousands except per share data)

	For the Years Ended December 31,				
	2012	2011	2010	2009	2008
Sales–Outside(A)	$4,825,946	$5,660,813	$4,938,703	$4,311,791	$4,181,569
Sales–Gas Royalty Interest(A)	49,405	66,929	62,869	40,951	79,302
Sales–Purchased Gas(A)	3,316	4,344	11,227	7,040	8,464
Freight–Outside(A)	141,936	231,536	125,715	148,907	216,968
Other Income	409,704	153,620	97,507	113,186	166,142
Total Revenue and Other Income	5,430,307	6,117,242	5,236,021	4,621,875	4,652,445
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	3,421,953	3,501,298	3,262,327	2,757,052	2,843,203
Gas Royalty Interests' Costs	38,867	59,331	53,775	32,376	73,962
Purchased Gas Costs	2,711	3,831	9,736	6,442	8,175
Freight Expense	141,936	231,347	125,544	148,907	216,968
Selling, General and Administrative Expenses	148,071	175,467	150,210	130,704	124,543
Depreciation, Depletion and Amortization	622,780	618,397	567,663	437,417	389,621
Interest Expense	220,060	248,344	205,032	31,419	36,183
Taxes Other Than Income	336,655	344,460	328,458	289,941	289,990
Abandonment of Long-Lived Assets	—	115,817	—	—	—
Loss on Debt Extinguishment	—	16,090	—	—	—
Transaction and Financing Fees	—	14,907	65,363	—	—
Black Lung Excise Tax Refund	—	—	—	(728)	(55,795)
Total Costs	4,933,033	5,329,289	4,768,108	3,833,530	3,926,850
Earnings Before Income Taxes	497,274	787,953	467,913	788,345	725,595
Income Taxes	109,201	155,456	109,287	221,203	239,934
Net Income	388,073	632,497	358,626	567,142	485,661
Less: Net Loss (Income) Attributable to Noncontrolling Interest	397	—	(11,845)	(27,425)	(43,191)
Net Income Attributable to CONSOL Energy Inc. Shareholders	$388,470	$632,497	$346,781	$539,717	$442,470
Earnings Per Share:					
Basic(B)	$1.71	$2.79	$1.61	$2.99	$2.43
Dilutive(B)	$1.70	$2.76	$1.60	$2.95	$2.40
Weighted Average Number of Common Shares Outstanding:					
Basic	227,593,524	226,680,369	214,920,561	180,693,243	182,386,011
Dilutive	229,141,767	229,003,599	217,037,804	182,821,136	184,679,592
Dividends Paid Per Share	$0.625	$0.425	$0.400	$0.400	$0.400

BALANCE SHEET DATA
(In thousands)

	December 31, 2012	2011	2010	2009	2008
Working capital (deficiency)	$151,995	$509,580	$(549,779)	$(487,550)	$(527,926)
Total assets	$12,670,909	$12,525,700	$12,070,610	$7,775,401	$7,535,458
Short-term debt	$62,919	$—	$484,000	$522,850	$722,700
Long-term debt (including current portion)	$3,188,071	$3,198,114	$3,210,921	$468,302	$490,752
Total deferred credits and other liabilities	$4,155,479	$4,348,995	$4,283,674	$3,849,428	$3,716,021
CONSOL Energy Inc. Stockholders' equity	$3,953,792	$3,610,885	$2,944,477	$1,785,548	$1,462,187

OTHER OPERATING DATA
(unaudited)

	Years Ended December 31, 2012	2011	2010	2009	2008
Coal:					
Tons sold (in thousands)(C)	56,909	63,278	63,297	57,771	66,017
Tons produced (in thousands)	55,987	62,048	61,733	59,038	64,858
Average sales price of tons produced ($ per ton produced)	$67.11	$72.25	$61.33	$58.70	$47.59
Average Cost of Goods Sold ($ per ton produced)	$52.42	$50.82	$45.49	$43.36	$39.89
Recoverable coal reserves (tons in millions)(D)	4,270	4,459	4,401	4,520	4,543
Number of active mining complexes (at end of period)	11	12	12	11	17
Gas:					
Net sales volumes produced (in billion cubic feet)	156.3	153.5	127.9	94.4	76.6
Average sales price ($ per mcf)(E)	$4.22	$4.90	$5.83	$6.68	$8.99
Average cost ($ per mcf)	$3.37	$3.53	$3.54	$3.15	$3.25
Proved reserves (in billion cubic feet)(F)	3,993	3,480	3,732	1,911	1,422

CASH FLOW STATEMENT DATA
(In thousands)

	For the Years Ended December 31, 2012	2011	2010	2009	2008
Net cash provided by operating activities	$728,129	$1,527,606	$1,131,312	$1,060,451	$989,864
Net cash used in investing activities(G)	$(1,000,410)	$(578,524)	$(5,543,974)	$(845,341)	$(1,098,856)
Net cash provided by (used in) financing activities	$(81,577)	$(606,140)	$4,379,849	$(288,015)	$205,853

OTHER FINANCIAL DATA
(Unaudited)
(In thousands)

	For the Years Ended December 31,				
	2012	2011	2010	2009	2008
Capital expenditures	$1,575,230	$1,382,371	$1,154,024	$920,080	$1,061,669
Adjusted EBIT(H)	$688,794	$1,159,285	$653,458	$786,520	$685,574
Adjusted EBITDA(H)	$1,311,574	$1,777,682	$1,221,121	$1,223,937	$1,075,195
Ratio of earnings to fixed charges(I)	2.58	3.53	2.74	11.76	10.67

(A) See Note 24–Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for sales and freight by operating segment.

(B) Basic earnings per share are computed using weighted average shares outstanding. Differences in the weighted average number of shares outstanding for purposes of computing dilutive earnings per share are due to the inclusion of the weighted average dilutive effect of employee and non-employee share-based compensation granted, totaling 1,548,243 shares, 2,323,230 shares, 2,117,243 shares, 2,127,893 shares, and 2,293,581 shares for the year ended December 31, 2012, 2011, 2010, 2009, and 2008, respectively.

(C) Includes sales of coal produced by CONSOL Energy and purchased from third parties. Of the tons sold, CONSOL Energy purchased the following amount from third parties: 0.5 million tons, 0.6 million tons, 0.3 million tons, 0.3 million tons, and 1.7 million tons for the years ended December 31, 2012, 2011, 2010, 2009 and 2008, respectively.

(D) Represents proven and probable coal reserves at period end.

(E) Represents average net sales price including the effect of derivative transactions.

(F) Represents proved developed and undeveloped gas reserves at period end.

(G) Net cash used in investing activities includes $327,964 for collection of Noble Note Receivable related to the 2011 agreement, $169,500 related to the disposition of the Northern Powder River Basin assets, $51,869 related to the disposition of the Ram River & Scurry Ram assets, $26,000 related to the disposition of the Elk Creek property, and $13,023 related to the disposition of the Burning Star No. 4 property in the year ended December 31, 2012. The year ended December 31, 2011 includes $485,464 related to the Noble transaction, $190,381 related to the Antero Transaction, and $54,099 related to the Hess Transaction. The year ended December 31, 2010 includes $3,470,212 and $991,034 related to the Dominion Acquisition and the purchase of CNX Gas Non-Controlling Interest, respectively.

(H) Adjusted EBIT is defined as earnings before deducting net interest expense (interest expense less interest income), income taxes, loss on debt extinguishment, and abandonment of long-lived assets. Adjusted EBITDA is defined as earnings before deducting net interest expense (interest expense less interest income), income taxes and depreciation, depletion and amortization. Although adjusted EBIT and adjusted EBITDA are not measures of performance calculated in accordance with generally accepted accounting principles, management believes that they are useful to an investor in evaluating CONSOL Energy because they are widely used in the coal industry as measures to evaluate a company's operating performance before debt expense and cash flow. Financial covenants in our credit facility include ratios based on adjusted EBITDA. Adjusted EBIT and adjusted EBITDA do not purport to represent cash generated by operating activities and should not be considered in isolation or as a substitute for measures of performance in accordance with generally accepted accounting principles. In addition, because adjusted EBIT and adjusted EBITDA are not calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. Management's discretionary use of funds depicted by adjusted EBIT and adjusted EBITDA may be limited by working capital, debt service and capital expenditure requirements, and by restrictions related to legal requirements, commitments and uncertainties. A reconcilement of adjusted EBIT and adjusted EBITDA to financial net income is as follows:

	For the Years Ended December 31,				
	2012	2011	2010	2009	2008
Net Income	$388,470	$632,497	$346,781	$539,717	$442,470
Add: Interest expense	220,060	248,344	205,032	31,419	36,183
Less: Interest income	(28,937)	(8,919)	(7,642)	(5,052)	(2,363)
Less: Interest income included in black lung excise tax refund	—	—	—	(767)	(30,650)
Add: Income tax expense	109,201	155,456	109,287	221,203	239,934
Add: Loss on Debt Extinguishment	—	16,090	—	—	—
Add: Abandonment of Long-Lived Assets	—	115,817	—	—	—
Adjusted Earnings before interest and taxes (Adjusted EBIT)	688,794	1,159,285	653,458	786,520	685,574
Add: Depreciation, depletion and amortization	622,780	618,397	567,663	437,417	389,621
Adjusted Earnings before interest, taxes and depreciation, depletion and amortization (Adjusted EBITDA)	$1,311,574	$1,777,682	$1,221,121	$1,223,937	$1,075,195

(I) For purposes of computing the ratio of earnings to fixed charges, earnings represent income before income taxes plus fixed charges. Fixed charges include (a) interest on indebtedness (whether expensed or capitalized), (b) amortization of debt discounts and premiums and capitalized expenses related to indebtedness and (c) the portion of rent expense we believe to be representative of interest.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

Overall demand for thermal coal decreased in 2012 versus 2011 levels from a sharp decrease in natural gas prices in early 2012 and a corresponding shift towards gas-fired generation, warm winter weather, as well as a modest decline in electric generation output. Over the course of 2012, coal-fired generation, however, regained domestic share of the power market from rising natural gas prices throughout 2012 which increased above the fuel switching breakeven point. Domestically, coal inventories at electric generators were elevated versus historical averages for much of the year. The hotter than normal summer, declining coal production, and rising thermal exports, all helped to reduce coal inventories in the latter part of the year. U.S. electric demand during the fourth quarter of 2012 is estimated to be slightly higher than 2011 levels, as weather returned to more normal patterns.

However, U.S. thermal coal exports enjoyed solid international demand in the first three quarters of 2012 but slowed slightly during the fourth quarter. Total 2012 thermal coal exports were up 50% from last year as producers sought demand abroad to offset weaker domestic demand noted above. Atlantic market spot coal prices fell throughout the year with an oversupply of U.S. coal hitting the European market. Spot prices began to flatten in the fourth quarter as supply moderated and winter season approached. Longer-term fundamentals for U.S. thermal coal exports remain favorable as subsidized mining in Europe is phased out, nuclear growth plans are curtailed, and coal continues to maintain a cost advantage over other more expensive oil-linked fuels.

Global steel demand has been under pressure and as a consequence, metallurgical coal used to make steel is in less demand. For 2012, metallurgical coal demand slowed as world blast furnace output grew by approximately 1%. Production grew, but demand was below the historical 6-8% growth rate recorded this past decade. In particular, Asian, European, and South American demand growth all slowed. We expect global infrastructure development will continue to drive future metallurgical and steel demand growth. Consistent with last year, China continues to provide the bulk of the world's blast furnace output with approximately 60% of world production. While demand growth was slowing, global metallurgical coal production growth remained strong. Global metallurgical coal supply grew in 2012, particularly from rising exports in Australia. International settlement prices declined throughout the year to levels much lower than 2011 highs, further underscoring an oversupplied market.

In response to the weak market conditions, CONSOL Energy idled its Buchanan Mine and its Amonate Complex in early September 2012. The Buchanan Mine resumed production the week of November 5 with a five-day work week schedule, while Amonate remained idled for the remainder of 2012. Buchanan typically produces about 400 thousand tons per month. Amonate was expected to produce about 35 thousand tons per month. Also in response to metallurgical and thermal market conditions, Buchanan and Blacksville No. 2 were both idled in March and April 2012. Our focus for 2013 will be to increase our target markets and customer base.

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. On December 14, 2012, CONSOL Energy issued another WARN of its intent to complete the idling of its Fola operations. The layoff is expected to occur during a 14-day period beginning on February 14, 2013. Layoffs are expected to affect 131 surface and office employees and 16 employees at the company's Little Eagle Deep Mine.

There was an over-supply of natural gas early in 2012 with the warm winter and modest economic environment. One bright spot for demand was record power generation output, as utilities capitalized on the sharp decline in natural gas prices early in the year. After several years of rising supply, natural gas production growth moderated with the decline in prices. The supply and demand imbalance narrowed as the year progressed as power generation rose, supply moderated, and imports of liquefied natural gas (LNG) and Western Canadian gas declined. Additionally, U.S. exports to eastern Canada and Mexico have increased to further balance the market. More normal weather, and a warmer than average July, put upward pressure on natural gas prices. During the fourth quarter in particular, prices rose on expectations of higher demand before moderating amid mild December temperatures.

Longer-term rebalancing will be aided by declining conventional production and the large shift in drilling focus for oil and “liquids rich” gas plays. As natural-gas-targeted rigs have fallen throughout the year, oil-targeted rigs have sharply increased. The widespread perception that shale gas production will yield lower and less volatile natural gas prices could spur additional demand as electric generators choose to build additional high-efficiency baseload gas power plants. Additional demand will come from the petrochemical industry and developing sources of demand such as increased wide-scale use of natural gas vehicles. The prospect of U.S. natural gas exports through LNG facilities is also under consideration. CONSOL Energy continues to believe that its natural gas assets will bring balance to CONSOL Energy's portfolio of long-lived energy resources.

A failure to return to normal weather patterns could have a negative short-term impact on CONSOL Energy's natural gas and domestic thermal coal demand. For much of 2012, the coal and natural gas industries worked through the effects of last year's mild winter temperatures. A repeat in 2013 could exacerbate existing strain. Additionally, uncertainty in the short term economic outlook could lead to a slowing of global economic expansion. Economic uncertainty is currently driven by the European sovereign debt crisis, lingering budget and political uncertainty in the U.S., increasing retirements of U.S. nuclear units, instability in the Middle East oil-producing region, and economic and political transitions in Asia. The fundamental long-term drivers of CONSOL Energy's business remain unchanged as the global demand for low-cost, reliable sources of energy and metallurgical coal remain strong in both the developed and developing world.

CONSOL Energy engaged in several asset sale transactions in the year ended December 31, 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.
- 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 and mid-vol forecasted coal production to increase from 150,000 tons in 2012 to 900,000 tons in 2015.
- In December 2012, CONSOL Energy sold non-producing western Canadian coal assets for $103 million. Ram River Coal Corp., a private Ontario company created by Forbes & Manhattan Inc. (F&M) (a private merchant bank headquartered in Toronto, Canada) acquired 100% of CONSOL Energy's Ram River and Scurry Ram coal properties for aggregate consideration of $105 million ($102.5 million payable to CONSOL Energy). On closing, Ram River Coal Corp. made an aggregate cash payment of $55.0 million ($52.5 million payable to CONSOL Energy) and under the terms of the asset purchase agreement provides for additional payments to CONSOL Energy of $25.5 million on or before June 21, 2013 and $24.5 million on or before June 21, 2014. The transaction resulted in an after-tax gain of $60.7 million.
- In December 2012, CONSOL Energy agreed to sell its interest in other coal assets, subject to certain conditions, in Alberta, for $24 million. The buyer is Riversdale Resources, headquartered in Sydney, Australia. The primary asset is Grassy Mountain Surface Mine. The sale is anticipated to close during the second quarter of 2013, and as such, no gain has been recognized as of December 31, 2012.
- CONSOL Energy continues to explore potential sales of assets.

CONSOL Energy engaged in several other transactions in the year ended December 31, 2012. These transactions include the following:

- In November 2012, CONSOL Energy offered a voluntary severance incentive program (VSIP) to active salaried corporate and operation support employees with 30 years of service, or more. Under this program, eligible employees who accepted the offer will receive a severance payment equal to one year's salary and the 2013 accrued vacation earned as of December 31, 2012. Approximately 100 employees volunteered for the program. Severance and vacation pay was approximately $13.3 million and was recognized in other accrued liabilities at December 31, 2012. These enhanced benefits were paid in January 2013.

- 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 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. CONSOL Energy has received $2.3 million of business interruption insurance proceeds related to this incident, included in its 2012 results of operations. Although CONSOL Energy's insurance claim is higher than the proceeds received to date, there is no guarantee that additional monies will be received.

- 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 served as the site to pilot test this solar powered water purification system. Initial testing of the Epiphany unit demonstrated the efficacy of the approach. Based on results of the pilot test, system improvements and upgrades are being implemented. Additional testing is ongoing and will be used to evaluate system enhancements in the coming months.
- 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 $9.4 million reduction in OPEB expense compared to what was originally expected to be recognized for the year ended December 31, 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.
- On December 10, 2012, CONSOL Energy's board of directors accelerated the declaration and payment of the regular quarterly dividend of $0.125 per share, payable on December 28, 2012, to shareholders of record on December 21, 2012.

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 year from previous years), (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 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.

- Other examples are the Mercury and Air Toxic Standards (MATS) (remanded by the court and reproposed by the EPA in November 2012) and the Utility Maximum Achievable Control Technology (Utility MACTS) rules issued by the EPA. These 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 NO_x. Although the EPA intends to reconsider certain aspects of these new rules, 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 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.
- In May 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 2012, 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 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.
- Under our joint venture agreements with Noble Energy and Hess, each of them has the right to perform due diligence on the title to the oil and gas interests which we conveyed to them and to assert that title to the acreage is defective. If they establish any title defects which are not resolved in favor of CONSOL Energy or if the subject acreage is reassigned to us at our request, then subject to certain deductibles, Noble's and Hess's respective aggregate carried cost obligation under the joint venture agreements will be reduced by the value the parties previously allocated to the affected acreage in the transaction. 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. To date, Noble has asserted formal title defects with respect to approximately 30,171 gross deal acres, which have an aggregate transaction value of $196 million. We believe that we will resolve most of those defects favorably to CONSOL Energy. To date, we have conceded defects to Noble which have an aggregate value equal to less than the applicable deductibles and the impact of these conceded defects on the Company's financial statements has not been material. In the case of our Ohio Utica Shale joint venture with Hess, based on title work performed by Hess, we believe that there are chain of title issues with respect to approximately 36,000 of the joint venture acres, most of which likely cannot be cured. Hess's 50% interest in these 36,000 acres has an allocated transaction value of approximately $146 million and may result in a corresponding reduction of the associated carried interest. The loss of these Utica Shale acres itself will not have a material impact on the Company's financial statements. After accounting for these defective acres, there are approximately 161,000 acres in our Ohio Utica Shale joint venture with Hess.
- A pension settlement charge is reasonably possible to occur in 2013. When lump sum payments from the pension plan exceed the service and interest expense, pension settlement accounting requires unamortized actuarial gains and loss related to the lump sum payouts be amortized immediately. The 2013 threshold for pension settlement recognition is

$55 million. If the threshold for pension settlement is reached, the pension settlement charge could be material to the financial results of CONSOL Energy. Also, pension settlement would require the pension plan to be remeasured using updated assumptions. The updated assumptions would include resetting the discount rate used in the actuarial calculation.

- CONSOL is also in negotiations with the authority that operates the Pittsburgh International Airport for the lease of the oil and gas rights on approximately 8,800 acres surrounding the airport. These are contiguous acres which are in the liquids area of the Marcellus Shale play.

Results of Operations
Year Ended December 31, 2012 Compared with Year Ended December 31, 2011

Net Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $388 million, or $1.70 per diluted share, for the year ended December 31, 2012. Net income attributable to CONSOL Energy shareholders was $632 million, or $2.76 per diluted share, for the year ended December 31, 2011.
The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $656 million of earnings before income tax for the year ended December 31, 2012 compared to $933 million for the year ended December 31, 2011. The total coal division sold 56.5 million tons of coal produced from CONSOL Energy mines, excluding our portion of tons sold from equity affiliates, for the year ended December 31, 2012 compared to 62.7 million tons for the year ended December 31, 2011.
The average sales price and average cost of goods sold per ton for all active coal operations were as follows:

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Average Sales Price per ton sold	$ 67.11	$ 72.25	$ (5.14)	(7.1)%
Average Costs of Goods Sold per ton	52.56	50.69	1.87	3.7 %
Margin	$ 14.55	$ 21.56	$ (7.01)	(32.5)%

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 renegotiations of domestic thermal contracts where pricing took effect January 1, 2012. The coal division priced 10.5 million tons on the export market at an average sales price of $76.33 per ton for the year ended December 31, 2012 compared to 11.7 million tons at an average price of $121.29 per ton for the year ended December 31, 2011. All other tons were sold on the domestic market. The decreased sales tonnage is primarily due to decreased coal demand in both thermal and metallurgical markets and curtailed shipments due to the Bailey Belt incident discussed previously.

Average costs per ton sold increased $1.87 per ton in the period-to-period comparison due primarily to the following:

- 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.
- 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 $2.16 per ton as the fixed costs were allocated over fewer tons.
- Average depreciation, depletion and amortization increased due to additional assets placed into service after the 2011 period.
- Average operating supplies and maintenance costs per ton increased due to additional equipment maintenance, timing of major equipment overhaul costs, increased fuel and lubricants and use of pumpable cribs for roof support.
- Average labor and labor related expenses increased primarily as result of the impact of the UMWA contract wage increases, offset, in part, by lower overtime hours worked.
- Average retirement and disability cost per ton decreased due to the improvement in other postretirement benefits discussed in the long-term liabilities section below.

The total gas division includes coalbed methane (CBM), shallow oil and gas, Marcellus and other gas. The total gas division contributed $39 million of earnings before income tax for the year ended December 31, 2012 compared to $130 million for the year ended December 31, 2011. Total gas production was 156.3 billion net cubic feet for the year ended December 31, 2012 compared to 153.5 billion net cubic feet for the year ended December 31, 2011. Total gas production increased primarily due to the on-going drilling program, partially offset by 10.7 billion net cubic feet of 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 average costs for all active gas operations were as follows:

67

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	$4.22	$4.90	$(0.68)	(13.9)%
Average Costs per thousand cubic feet sold	3.37	3.53	(0.16)	(4.5)%
Margin	$0.85	$1.37	$(0.52)	(38.0)%

Total gas division outside sales revenues were $660 million for the year ended December 31, 2012 compared to $752 million for the year ended December 31, 2011. The decrease was primarily due to the 13.9% reduction in average price per thousand cubic feet sold, offset, in part, by the 2% increase in volumes sold. The decrease in average sales price is the result 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 76.9 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2012 at an average price of $5.25 per thousand cubic feet. These financial hedges represented 84.0 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2011 at an average price of $5.21 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 the 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 as compared with the prior year 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.

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 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 period 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 Years Ended December 31,			
	2012	2011	Variance	Percent Change
Employee wages and related expenses	$60	$68	$(8)	(11.8)%
Consulting and professional services	32	37	(5)	(13.5)%
Contributions	16	15	1	6.7%
Miscellaneous	28	32	(4)	(12.5)%

Total Company General and Administrative Expenses	$136	$152	$(16)	(10.5)%

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

- Employee wages and related expenses decreased $8 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 $5 million in the period-to-period comparison due to a reduction in CONSOL Energy's advertising and promotion campaign.
- Contributions increased $1 million in the period-to-period comparison due to various transactions, none of which were individually material.
- Miscellaneous general and administrative expenses decreased $4 million in the period-to-period comparison due to various transactions throughout both periods, 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 calculated liabilities was $258 million for the year ended December 31, 2012 compared to $332 million for the year ended December 31, 2011. The decrease 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 15—Pension and Other Postretirement Benefit Plans and Note 16—Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details related to total Company expense increases.

TOTAL COAL SEGMENT ANALYSIS for the year ended December 31, 2012 compared to the year ended December 31, 2011:

The coal segment contributed $656 million of earnings before income tax in the year ended December 31, 2012 compared to $933 million in the year ended December 31, 2011.

	For the Year Ended December 31, 2012					Increase (Decrease) from Year Ended December 31, 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	$3,046	$229	$506	$6	$3,787	$(12)	$(139)	$(566)	$(21)	$(738)
Purchased Coal	—	—	—	19	19	—	—	—	(23)	(23)
Total Outside Sales	3,046	229	506	25	3,806	(12)	(139)	(566)	(44)	(761)
Freight Revenue	—	—	—	142	142	—	—	—	(90)	(90)
Other Income	1	6	—	323	330	(5)	(5)	—	261	251
Total Revenue and Other Income	3,047	235	506	490	4,278	(17)	(144)	(566)	127	(600)
Costs and Expenses:										
Beginning inventory costs	89	2	16	—	107	(9)	2	6	—	(1)
Total direct costs	1,539	105	185	172	2,001	(4)	(37)	(34)	20	(55)
Total royalty/production taxes	201	10	31	3	245	(5)	(4)	(36)	(5)	(50)
Total direct services to operations	239	22	21	290	572	(9)	(8)	(1)	39	21
Total retirement and disability	179	12	27	20	238	(53)	(8)	(14)	4	(71)
Depreciation, depletion and amortization	301	24	37	34	396	(1)	(7)	—	(96)	(104)
Ending inventory costs	(58)	—	(21)	—	(79)	32	—	(5)	—	27
Total Costs and Expenses	2,490	175	296	519	3,480	(49)	(62)	(84)	(38)	(233)
Freight Expense	—	—	—	142	142	—	—	—	(90)	(90)
Total Costs of Goods Sold	2,490	175	296	661	3,622	(49)	(62)	(84)	(128)	(323)
Earnings (Loss) Before Income Taxes	$557	$60	$210	$(171)	$656	$32	$(82)	$(482)	$255	$(277)

THERMAL COAL SEGMENT

The thermal coal segment contributed $557 million to total Company earnings before income tax for the year ended December 31, 2012 compared to $525 million for the year ended December 31, 2011. The thermal coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Company Produced Thermal Tons Sold (in millions)	49.1	52.0	(2.9)	(5.6%)
Average Sales Price Per Thermal Ton Sold	$61.99	$58.87	$3.12	5.3%
Beginning Inventory Costs Per Thermal Ton	$58.32	$51.73	$6.59	12.7%
Total Direct Operating Costs Per Thermal Ton Produced	$31.56	$29.86	$1.70	5.7%
Total Royalty/Production Taxes Per Thermal Ton Produced	4.14	4.00	0.14	3.5%
Total Direct Services to Operations Per Thermal Ton Produced	4.90	4.81	0.09	1.9%
Total Retirement and Disability Per Thermal Ton Produced	3.68	4.48	(0.80)	(17.9%)
Total Depreciation, Depletion and Amortization Costs Per Thermal Ton Produced	6.19	5.84	0.35	6.0%
Total Production Costs Per Thermal Ton Produced	$50.47	$48.99	$1.48	3.0%
Ending Inventory Costs Per Thermal Ton	$(50.94)	$(58.32)	$(7.38)	(12.7%)
Total Costs of Goods Sold Per Thermal Ton Sold	$50.68	$48.88	$1.80	3.7%
Average Margin Per Thermal Ton Sold	$11.31	$9.98	$1.33	13.3%

Thermal coal revenue was $3,046 million for the year ended December 31, 2012 compared to $3,058 million for the year ended December 31, 2011. The $12 million decrease was attributable to 2.9 million fewer tons sold in 2012 partially offset by a $3.12 per ton higher average sales price. The higher average thermal coal sales price in the 2012 period was the result of the successful renegotiations of several domestic thermal contracts during 2012. The thermal coal segment was also impacted by 3.6 million tons of thermal coal sold on the high volatile metallurgical coal market for the year ended December 31, 2012, which was 1.1 million tons less than the tons sold in the year ended December 31, 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 costs 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 $2,490 million for the year ended December 31, 2012, or $49 million lower than the $2,539 million for the year ended December 31, 2011. Although total cost of goods sold dollars were improved, total costs per ton sold on a unit basis were impaired. Total cost of goods sold for thermal coal was $50.68 per ton in the year ended December 31, 2012 compared to $48.88 per ton in the year ended December 31, 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 $1.10 per ton. 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 $1,539 million for the year ended December 31, 2012 compared to $1,543 million for the year ended December 31, 2011. Direct operating costs were $31.56 per ton produced in the current year compared to $29.86 per ton produced in the prior year. 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. Thermal mines produced 48.8 million tons in 2012 compared to 51.7 million tons in 2011. 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 months of March and 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 year-to-year 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 serviced in the current year. 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 $5 million to $201 million in the current year. Average cost per thermal ton produced increased $0.14 per ton due to 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 $239 million in the current year compared to $248 million in the prior year. Direct services to the operations were $4.90 per ton in the current year compared to $4.81 per ton in the prior year. 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 year-to-year 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 year-to-year 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 retirement and disability costs attributable to the thermal coal segment were $179 million for the year ended December 31, 2012 compared to $232 million for the year ended December 31, 2011. The decrease in the thermal coal retirement and disability costs was primarily attributable to a change 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 $301 million for the year ended December 31, 2012 compared to $302 million for the year ended December 31, 2011. The decrease was primarily due to lower depletion directly related to lower production volumes. Unit costs per thermal ton produced were higher for the year ended December 31, 2012 compared to the year ended December 31, 2011 due to additional equipment and infrastructure placed into service after the 2011 year that is depreciated on a straight-line basis.
Changes in thermal coal inventory volumes and carrying value, resulted in $31 million of costs of goods sold for the year ended December 31, 2012 compared to $8 million for the year ended December 31, 2011. Thermal coal inventory was 1.1 million tons at December 31, 2012 compared to 1.5 million tons at December 31, 2011.

HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $60 million to total Company earnings before income tax for the year ended December 31, 2012 compared to $142 million for the year ended December 31, 2011. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Years Ended December 31,			
	2012	2011	Increase (Decrease)	Percent Change
Company Produced High Vol Met Tons Sold (in millions)	3.6	4.7	(1.1)	(23.4%)
Average Sales Price Per High Vol Met Ton Sold	$63.76	$78.06	$(14.30)	(18.3%)
Beginning Inventory Costs Per High Vol Met Ton	$63.50	$—	$63.50	—%
Total Direct Operating Costs Per High Vol Met Ton Produced	$29.30	$30.15	$(0.85)	(2.8%)
Total Royalty/Production Taxes Per High Vol Met Ton Produced	2.83	3.01	(0.18)	(6.0%)
Total Direct Services to Operations Per High Vol Met Ton Produced	6.15	6.26	(0.11)	(1.8%)
Total Retirement and Disability Per High Vol Met Ton Produced	3.24	4.28	(1.04)	(24.3%)
Total Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Produced	6.62	6.50	0.12	1.8%
Total Production Costs Per High Vol Met Ton Produced	$48.14	$50.20	$(2.06)	(4.1%)
Ending Inventory Costs Per High Vol Met Ton	$—	$—	$—	—%
Total Costs Per High Vol Met Ton Sold	$48.85	$50.20	$(1.35)	(2.7%)
Margin Per High Vol Met Ton Sold	$14.91	$27.86	$(12.95)	(46.5%)

High volatile metallurgical coal revenue was $229 million for the year ended December 31, 2012 compared to $368 million for the year ended December 31, 2011. Average sales prices for high volatile metallurgical coal decreased $14.30 per ton in the year-to-year comparison due to a weakening in global metallurgical coal demand. CONSOL Energy priced 3.1 million tons of high volatile metallurgical coal in the export market at an average sales price of $60.87 per ton for the year ended December 31, 2012 compared to 4.3 million tons at an average price of $77.48 per ton for the year ended December 31, 2011. The remaining tons sold in the year-to-year comparison were sold in the domestic market.

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

Total cost of goods sold are comprised of changes in high volatile metallurgical coal inventory and costs of tons produced in the period. Total cost of goods sold for high volatile metallurgical coal was $175 million for the year ended December 31, 2012, or $62 million lower than the $237 million for the year ended December 31, 2011. Total cost of goods sold for high volatile metallurgical coal was $48.85 per ton in the year ended December 31, 2012 compared to $50.20 per ton in the year ended December 31, 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 $105 million in the year ended December 31, 2012 compared to $142 million in the year ended December 31, 2011. Direct operating costs dollars are improved due to lower tons produced in the year-to-year comparison and due to cost control measures that were implemented. Direct operating costs were $29.30 per ton produced in the current year compared to $30.15 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:

- 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.

- Mine maintenance and supplies per ton produced decreased due to the mix of mines producing tons that were shipped as high volatile metallurgical coal. Mines with lower cost structures produced a larger portion of the high volatile metallurgical coal shipped in the current year compared to the prior year.
- Various other unit costs including power and miscellaneous costs did not change significantly individually or in total.

Royalties and production taxes improved $4 million to $10 million in the current year compared to $14 million in the prior year. The improvement was due to lower volumes and by lower higher average sales prices. High volatile metallurgical coal royalties and production taxes were $2.83 per ton in the current year compared to $3.01 per ton in the prior year. Average cost per high volatile metallurgical ton produced decreased due to a change in the mix of coal produced both geographically and in ownership, which changed the production tax and royalty rates, respectively.
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 $22 million in the current year compared to $30 million in the prior year. 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 $6.15 per ton in the current year compared to $6.26 per ton in the prior year. Changes in the average direct service to operations cost per ton for high volatile metallurgical coal produced were primarily related to a reduction of commission rates due to a decrease in the average sales price.
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 $12 million for the year ended December 31, 2012 compared to $20 million for the year ended December 31, 2011. The decrease in the high volatile metallurgical coal retirement and disability costs was primarily attributable to a change 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 $24 million for the year ended December 31, 2012 compared to $31 million for the year ended December 31, 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 year ended December 31, 2012 compared to the year ended December 31, 2011 due to additional equipment and infrastructure placed into service after the 2011 year that is depreciated on a straight-line basis.
Changes in high volatile metallurgical coal inventory resulted in $2 million of cost of goods sold in the year ended December 31, 2012. There was no high volatile metallurgical coal inventory at December 31, 2012.

LOW VOL METALLURGICAL COAL SEGMENT

The low volatile metallurgical coal segment contributed $210 million to total Company earnings before income tax in the year ended December 31, 2012 compared to $692 million in the year ended December 31, 2011. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Company Produced Low Vol Met Tons Sold (in millions)	3.7	5.6	(1.9)	(33.9%)
Average Sales Price Per Low Vol Met Ton Sold	$140.11	$191.81	$(51.70)	(27.0%)
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	$50.98	$38.71	$12.27	31.7%
Total Royalty/Production Taxes Per Low Vol Met Ton Produced	8.32	11.74	(3.42)	(29.1%)
Total Direct Services to Operations Per Low Vol Met Ton Produced	5.93	3.77	2.16	57.3%
Total Retirement and Disability Per Low Vol Met Ton Produced	7.63	7.28	0.35	4.8%
Total Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Produced	10.23	6.54	3.69	56.4%
Total Production Costs Per Low Vol Met Ton Produced	$83.09	$68.04	$15.05	22.1%
Ending Inventory Costs Per Low Vol Met Ton	$(86.38)	$(67.60)	$18.78	27.8%
Total Costs Per Low Vol Met Ton Sold	$81.89	$67.90	$13.99	20.6%
Margin Per Low Vol Met Ton Sold	$58.22	$123.91	$(65.69)	(53.0%)

Low volatile metallurgical coal revenue was $506 million for the year ended December 31, 2012 compared to $1,072 million for the year ended December 31, 2011. The $566 million decrease was attributable to a $51.70 per ton lower average sales price and nearly two million tons in volumes. Average sales prices for low volatile metallurgical coal decreased in the year-to-year comparison due to the weakening in global metallurgical coal demand. For the year ended December 31, 2012, 2.6 million tons of low volatile metallurgical coal was priced on the export market at an average price of $125.73 per ton compared to 4.6 million tons at an average price of $196.46 per ton for the 2011 year. The remaining tons sold in the year-to-year comparison were sold on the domestic market.

Total cost of goods sold are comprised of changes in low volatile metallurgical coal inventory and costs of tons produced in the period. Total cost of goods sold for low volatile metallurgical coal was $296 million for the year ended December 31, 2012, or $84 million lower than the $380 million for the year ended December 31, 2011. Total cost of goods sold for low volatile metallurgical coal was $81.89 per ton for the year ended December 31, 2012 compared to $67.90 per ton for the year ended December 31, 2011. The increase in cost 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 $185 million for the year ended December 31, 2012 compared to $219 million for the year ended December 31, 2011. Direct operating costs dollars are improved $34 million due to lower tons produced in the year-to-year comparison and cost control measures implemented, however, the cost improvements did not offset the impact of reduced production on unit costs. Direct operating costs were $50.98 per ton produced in the current year compared to $38.71 per ton produced in the prior year. 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 $18.53 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 3.7 million tons for the year ended December 31, 2012 compared to 5.7 million tons for the year ended December 31, 2011. Production was significantly lower in the year-to-year 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. Production resumed in early November 2012 with a five day work week instead of the normal seven day work week. Fixed costs were then spread over fewer tons produced which increased all costs on a per unit basis. Buchanan Mine was also idled in March and April 2012 which impacted production.

Royalties and production taxes improved $36 million to $31 million in the current year-to-date period compared to $67 million in the prior year-to-date period. Unit costs also improved $3.42 per low volatile metallurgical ton produced to $8.32 per ton in the current year-to-date period compared to $11.74 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 $21 million in the current year compared to $22 million in the prior year. Direct services to the operations for low volatile metallurgical coal were $5.93 per ton in the current year compared to $3.77 per ton in the prior year. 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 retirement and disability costs attributable to the low volatile metallurgical coal segment were $27 million for the year ended December 31, 2012 compared to $41 million for the year ended December 31, 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 $37 million for both the years ended December 31, 2012 and 2011. Unit costs per low volatile metallurgical ton produced were higher in the year ended December 31, 2012 compared to the year ended December 31, 2011 due to lower volumes produced.

Changes in low volatile metallurgical coal inventory volumes and carrying value resulted in $5 million of cost of goods sold in the year ended December 31, 2012 compared to $6 million of cost of goods sold in the year ended December 31, 2011. Produced low volatile metallurgical coal inventory was 0.2 million tons at December 31, 2012 and December 31, 2011.

OTHER COAL SEGMENT

The other coal segment had a loss before income tax of $171 million for the year ended December 31, 2012 compared to a loss before income tax of $426 million for the year ended December 31, 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.

The 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 year ended December 31, 2012 compared to 0.4 million tons for the year ended December 31, 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 $19 million for the year ended December 31, 2012 compared to $42 million for the year ended December 31, 2011. The decrease was primarily due to increased volumes sold partially offset by a decrease in the average sales price.

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 almost completely offset in freight expense. Freight revenue was $142 million for the year ended December 31, 2012 compared to $232 million for the year ended December 31, 2011. The $90 million decrease in freight revenue was due to decreased shipments where CONSOL Energy contractually provides transportation services.
Miscellaneous other income was $323 million for the year ended December 31, 2012 compared to $62 million for the year ended December 31, 2011. The $261 million increase is due to the following items:

- Gain on sale of assets attributable to the Other Coal segment were $271 million for the year ended December 31, 2012 compared to $5 million for the year ended December 31, 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 Western Canada, Illinois and West Virginia that resulted in income of $112 million. See Note 2—Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional detail of these sales. The remaining $3 million change was related to various transactions that occurred throughout both periods, none of which were individually material.
- For the year ended December 31, 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 December 31, 2011.
- Gain on issuances of pipeline right-of-ways to third parties decreased $8 million in the year-to-year comparison, primarily due to a $10 million pipeline right-of-way to a third party issued in the year ended December 31, 2011.
- The remaining $9 million decrease in a year-to-year comparison is due to several transactions, none of which are individually material.

Other coal segment total costs were $661 million for the year ended December 31, 2012 compared to $789 million for the year ended December 31, 2011. The decrease of $128 million was due to the following items:

	For the Years Ended December 31,			
	2012	2011	Variance	
Abandonment of long-lived assets	$—	$116	$(116	)
Freight expense	142	231	(89	)
Purchased Coal	47	71	(24	)
General and Administrative Expense	91	98	(7	)
Litigation Contingencies	18	8	10	
Voluntary Incentive Separation Program	13	—	13	
Bailey Belt Incident	41	—	41	
Closed and idle mines	153	107	46	
Other	156	158	(2	)
Total other coal segment costs	$661	$789	$(128	)

- Abandonment of long-lived assets was $116 million for the year ended December 31, 2011 as a result of permanently idling 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 almost completely offset in freight revenue. The $89 million decrease in freight revenue was due to decreased shipments which CONSOL Energy contractually provides transportation services.
- Purchased coal costs decreased approximately $24 million in the year-to-year comparison primarily due to differences in the quality of coal purchased, decreases in the market price of coal purchased, and an increase in the volumes of coal purchased in the period-to-period comparison.
-

General and Administrative Expense related to the other coal segment decreased by $7 million primarily due to a reduction of wages and related expenses.

- Litigation contingencies increased $10 million in the year-to-year comparison due to various items. See Note 23-Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details related to total Company expense.

- In November 2012, CONSOL Energy offered a voluntary severance incentive program (VSIP) to active salaried corporate and operation support employees with 30 years of service, or more. Under this program, eligible employees who accepted the offer will receive a severance payment equal to one year's salary and the 2013 accrued vacation earned as of December 31, 2012. Approximately 100 employees volunteered for the program. Severance and vacation pay was approximately $13 million and was recognized for the year ended December 31, 2012. This was paid in January 2013.
- Bailey Belt incident costs represents expenses related to continued advancement of the mines and on-going projects at the mines that took place during the idled phase when belt reconstruction was occurring.
- Closed and idle mine costs increased approximately $46 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. The increase was the result of $30 million additional costs related to reclamation liabilities and on-going idling costs incurred at the Fola Complex for the year ended December 31, 2012. Closed and idle mine costs increased $20 million as the result of a 2012 decision to temporarily idle Buchanan Mine in 2012. Closed and idle mine costs decreased $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.
- Other costs related to the coal segment decreased $2 million due to various other transactions that occurred throughout both periods, none of which are individually material.

TOTAL GAS SEGMENT ANALYSIS for the year ended December 31, 2012 compared to the year ended December 31, 2011:
The gas segment contributed $39 million to earnings before income tax for the year ended December 31, 2012 compared to $130 million for the year ended December 31, 2011.

	For the Year Ended December 31, 2012					Difference to Year Ended December 31, 2011				
	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$379	$135	$134	$10	$658	$(82)	$(20)	$15	$(2)	$(89)
Related Party	2	—	—	—	2	(3)	—	—	—	(3)
Total Outside Sales	381	135	134	10	660	(85)	(20)	15	(2)	(92)
Gas Royalty Interest	—	—	—	50	50	—	—	—	(17)	(17)
Purchased Gas	—	—	—	3	3	—	—	—	(1)	(1)
Other Income	—	—	—	57	57	—	—	—	(2)	(2)
Total Revenue and Other Income	381	135	134	120	770	(85)	(20)	15	(22)	(112)
Lifting	37	40	12	2	91	(3)	(9)	(3)	1	(14)
Ad Valorem, Severance, and Other Taxes	10	10	4	2	26	(2)	(2)	3	1	—
Gathering	106	26	24	5	161	8	(1)	9	3	19
Gas Direct Administrative, Selling & Other	14	13	17	3	47	(15)	(8)	6	3	(14)
Depreciation, Depletion and Amortization	88	59	47	9	203	(13)	(2)	12	(1)	(4)
General & Administration	—	—	—	40	40	—	—	—	(11)	(11)
Gas Royalty Interest	—	—	—	39	39	—	—	—	(20)	(20)
Purchased Gas	—	—	—	3	3	—	—	—	(1)	(1)
Exploration and Other Costs	—	—	—	39	39	—	—	—	21	21
Other Corporate Expenses	—	—	—	77	77	—	—	—	12	12
Interest Expense	—	—	—	5	5	—	—	—	(5)	(5)
Total Cost	255	148	104	224	731	(25)	(22)	27	3	(17)
Earnings Before Noncontrolling Interest and Income Tax	126	(13)	30	(104)	39	(60)	2	(12)	(25)	(95)
Noncontrolling Interest	—	—	—	—	—	—	—	—	(4)	(4)
Earnings Before Income Tax	$126	$(13)	$30	$(104)	$39	$(60)	$2	$(12)	$(21)	$(91)

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $126 million to the total Company earnings before income tax for the year ended December 31, 2012 compared to $186 million for the year ended December 31, 2011.

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Produced gas CBM sales volumes (in billion cubic feet)	88.2	92.4	(4.2)	(4.5)%
Average CBM sales price per thousand cubic feet sold	$4.32	$5.05	$(0.73)	(14.5)%
Average CBM lifting costs per thousand cubic feet sold	$0.42	$0.43	$(0.01)	(2.3)%
Average CBM ad valorem, severance, and other taxes per thousand cubic feet sold	$0.12	$0.13	$(0.01)	(7.7)%
Average CBM gathering costs per thousand cubic feet sold	$1.21	$1.06	$0.15	14.2%
Average CBM direct administrative, selling & other costs per thousand cubic feet sold	$0.16	$0.31	$(0.15)	(48.4)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	$0.98	$1.10	$(0.12)	(10.9)%
Total Average CBM costs per thousand cubic feet sold	$2.89	$3.03	$(0.14)	(4.6)%
Average Margin for CBM	$1.43	$2.02	$(0.59)	(29.2)%

CBM sales revenues were $381 million for the year ended December 31, 2012 compared to $466 million for the year ended December 31, 2011. The $85 million decrease was primarily due to a 14.5% decrease in average sales price per thousand cubic feet sold, coupled with a 4.5% decrease in average volumes sold. The decrease in CBM average sales price is the result of various gas swap transactions that matured in each period and lower average market prices. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 45.8 billion cubic feet of our produced CBM gas sales volumes for the year ended December 31, 2012 at an average price of $5.34 per thousand cubic feet. For the year ended December 31, 2011, these financial hedges represented 61.8 billion cubic feet at an average price of $5.36 per thousand cubic feet. CBM sales volumes decreased 4.2 billion cubic feet primarily due to normal well declines without corresponding increase in wells drilled and the impact on gas production from the idling of Buchanan Mine during the 2012 period. Currently, the focus of the gas division is to develop its Marcellus and Utica acreage.

Total costs for the CBM segment were $255 million for the year ended December 31, 2012 compared to $280 million for the year ended December 31, 2011. Lower costs in the period-to-period comparison are discussed below.

CBM lifting costs were $37 million for the year ended December 31, 2012 compared to $40 million for the year ended December 31, 2011. The $3 million decrease is primarily due to idle rig costs incurred during the 2011 period, reduced road maintenance costs, offset, in part, by increased slip repairs.

CBM ad valorem, severance, and other taxes were $10 million for the year ended December 31, 2012 compared to $12 million for the year ended December 31, 2011. The decrease in total dollars was primarily due to reduced severance tax expense caused by lower average gas sales price during 2012. These changes resulted a $0.01 reduction to average unit costs.

CBM gathering costs were $106 million for the year ended December 31, 2012 compared to $98 million for the year ended December 31, 2011. Higher average CBM gathering unit costs are related to increased compressor maintenance, additional equipment lease rentals and lower volumes sold in the period-to-period comparison.

CBM direct administrative, selling & other costs for the CBM segment were $14 million for the year ended December 31, 2012 compared to $29 million for the year ended December 31, 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 $88 million for the year ended December 31, 2012 compared to $101 million for the year ended December 31, 2011. There was approximately $60 million, or $0.67 per unit-of-production, of depreciation, depletion and amortization related to CBM gas and related well equipment that was reflected on a units-of-production method of depreciation in the year ended December 31, 2012. The production portion of depreciation, depletion and amortization was $72 million, or $0.78 per unit-of-production in the year ended December 31, 2011. The CBM unit-of-production rate decreased due to revised rates which are generally calculated using the net book value of assets divided by either proved or proved developed reserve additions. There was approximately $28 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 year ended December 31, 2012. The non-production related depreciation, depletion and amortization was $29 million, or $0.32 per thousand cubic feet for the year ended December 31, 2011.

SHALLOW OIL AND GAS SEGMENT

The shallow oil and gas segment had a loss before income tax of $13 million for the year ended December 31, 2012 compared to a loss before income tax of $15 million for the year ended December 31, 2011.

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Produced gas Shallow Oil and Gas sales volumes (in billion cubic feet)	29.2	32.2	(3.0)	(9.3)%
Average Shallow Oil and Gas sales price per thousand cubic feet sold	$4.64	$4.83	$(0.19)	(3.9)%
Average Shallow Oil and Gas lifting costs per thousand cubic feet sold	$1.37	$1.52	$(0.15)	(9.9)%
Average Shallow Oil and Gas ad valorem, Severance, and other taxes per thousand cubic feet sold	$0.35	$0.37	$(0.02)	(5.4)%
Average Shallow Oil and Gas gathering costs per thousand cubic feet sold	$0.92	$0.83	$0.09	10.8%
Average Shallow Oil and Gas direct administrative, selling & other costs per thousand cubic feet sold	$0.45	$0.67	$(0.22)	(32.8)%
Average Shallow Oil and Gas depreciation, depletion and amortization costs per thousand cubic feet sold	$2.02	$1.90	$0.12	6.3%
Total Average Shallow Oil and Gas costs per thousand cubic feet sold	$5.11	$5.29	$(0.18)	(3.4)%
Average Margin for Shallow Oil and Gas	$(0.47)	$(0.46)	$(0.01)	2.2%

Shallow oil and gas sales revenues were $135 million for the year ended December 31, 2012 compared to $155 million for the year ended December 31, 2011. The $20 million decrease was primarily due to the 9.3% decrease in volumes sold as well as the 3.9% decrease in average sales price. The decrease in shallow oil and gas average sales price is the result of lower average 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 approximately18.5 billion cubic feet of our produced shallow oil and gas sales volumes for the year ended December 31, 2012 at an average price of $5.23 per thousand cubic feet. For the year ended December 31, 2011, these financial hedges represented 11.5 billion cubic feet at an average price of $4.97 per thousand cubic feet. Shallow oil and gas sales volumes decreased 3.0 billion cubic feet primarily due to normal well declines without corresponding increase in wells drilled.

Total costs for the shallow oil and gas segment were $148 million for the year ended December 31, 2012 compared to $170 million for the year ended December 31, 2011. Lower costs in the period-to-period comparison are discussed below.

Shallow oil and gas lifting costs were $40 million for the year ended December 31, 2012 compared to $49 million for the year ended December 31, 2011. Lifting costs per unit decreased $0.15 per thousand cubic feet sold primarily due to lower road maintenance, decreased well tending expenses and decreased swabbing and fishing expenses in the period-to-period comparison.

Shallow oil and gas ad valorem, severance and other taxes were $10 million for the year ended December 31, 2012 compared to $12 million for the year ended December 31, 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 2012.

Shallow oil and gas gathering costs were $26 million for the year ended December 31, 2012 compared to $27 million for the year ended December 31, 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 was offset by lower sales volumes.

Shallow oil and gas direct administrative, selling & other costs were $13 million for the year ended December 31, 2012 compared to $21 million for the year ended December 31, 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 $8 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 $59 million for the year ended December 31, 2012 compared to $61 million for the year ended December 31, 2011. There was approximately $51 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 in the year ended December 31, 2012. There was approximately $54 million, or $1.67 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 year ended December 31, 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 $8 million, or $0.27 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 year ended December 31, 2012. There was $7 million, or $0.23 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the year ended December 31, 2011. The increase was related to additional infrastructure and equipment placed in the 2012 period.

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $30 million to the total Company earnings before income tax for the year ended December 31, 2012 compared to $42 million for the year ended December 31, 2011.

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Produced gas Marcellus sales volumes (in billion cubic feet)	36.5	26.9	9.6	35.7 %
Average Marcellus sales price per thousand cubic feet sold	$3.68	$4.43	$(0.75)	(16.9)%
Average Marcellus lifting costs per thousand cubic feet sold	$0.34	$0.56	$(0.22)	(39.3)%
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	$0.67	$0.54	$0.13	24.1 %
Average Marcellus direct administrative, selling & costs per thousand cubic feet sold	$0.46	$0.41	$0.05	12.2 %
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	$1.30	$1.33	$(0.03)	(2.3)%
Total Average Marcellus costs per thousand cubic feet sold	$2.89	$2.89	$—	— %
Average Margin for Marcellus	$0.79	$1.54	$(0.75)	(48.7)%

The Marcellus segment sales revenues were $134 million for the year ended December 31, 2012 compared to $119 million for the year ended December 31, 2011. The $15 million increase was primarily due to a 35.7% increase in volumes sold, offset, in part, by a 16.9% decrease in average sales price per thousand cubic feet sold. The decrease in Marcellus average sales price was the result of the decline in general market prices; offset, in part, by various gas swap transactions that matured in the year ended December 31, 2012. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These hedges represented approximately 12.4 billion cubic feet of our produced Marcellus gas sales volumes for the year ended December 31, 2012 at an average price of $4.99 per thousand cubic feet. For the year ended December 31, 2011, these financial hedges represented 10.6 billion cubic feet at an average price of $4.64 per thousand cubic feet. Marcellus sales volumes increased 9.6 billion cubic feet due to our on-going drilling program.

Total costs for the Marcellus Segment were $104 million for the year ended December 31, 2012 compared to $77 million for the year ended December 31, 2011. The average costs in the period-to-period comparison are discussed below.

Marcellus lifting costs were $12 million for the year ended December 31, 2012 compared to $15 million for the year ended December 31, 2011. Lifting costs decreased primarily due to lower well servicing costs, well tending costs and additional sales volumes during the 2012 year-to-date period. These improvements, along with additional sales volumes resulted in a $0.22 improvement to average unit costs.

Marcellus ad valorem, severance and other taxes were $4 million for the year ended December 31, 2012 compared to $1 million for the year ended December 31, 2011. The increase of $0.07 per thousand cubic feet sold 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 $24 million for the year ended December 31, 2012 compared to $15 million for the year ended December 31, 2011. Average gathering costs increased $0.13 per unit primarily due to increased firm transportation usage and the formation of CONE Gathering LLC (CONE), a 50% owned affiliate. CONE began charging CONSOL Energy a fixed gathering rate of $0.46 per MMBTU on Marcellus production volumes during the 4th quarter of 2011.

Marcellus direct administrative, selling & other costs were $17 million for the year ended December 31, 2012 compared to $11 million for the year ended December 31, 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 increase in the period-to-period comparison is due to increased direct administrative labor and Marcellus volumes representing a larger proportion of total natural gas volumes.

Depreciation, depletion and amortization costs were $47 million for the year ended December 31, 2012 compared to $35 million for the year ended December 31, 2011. There was approximately $44 million, or $1.24 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 year ended December 31, 2012. There was approximately $27 million, or $1.04 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 year ended December 31, 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 $3 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 for the year ended December, 31 2012. There was $8 million, or $0.29 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 year ended December 31, 2011. The decrease in Marcellus gathering and other equipment depreciation, depletion and amortization related 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 Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information.

OTHER GAS SEGMENT

The other gas segment includes activity not assigned to the CBM, Shallow oil & 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 this operation was approximately $10 million for the year ended December 31, 2012 and $12 million for the year ended December 31, 2011. Total costs related to these other sales were $20 million for the 2012 period and were $14 million for the 2011 period. The increase in costs in the period-to-period comparison were primarily attributable to increased gathering and direct administrative, selling & other costs 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 division. Royalty interest gas sales revenue was $50 million for the year ended December 31, 2012 compared to $67 million for the year ended December 31, 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 Years Ended December 31,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	18.0	16.4	1.6	9.8 %
Average Sales Price Per thousand cubic feet	$ 2.74	$ 4.07	$ (1.33)	(32.7)%

83

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $3 million for the year ended December 31, 2012 compared to $4 million for the year ended December 31, 2011.

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	1.1	1.0	0.1	10.0 %
Average Sales Price Per thousand cubic feet	$ 3.03	$ 4.28	$ (1.25)	(29.2)%

Other income was $57 million for the year ended December 31, 2012 compared to $59 million for the year ended December 31, 2011. The $2 million decrease was primarily due to the following items:

- Gain on sale of assets decreased $30 million due to gains on the Hess transaction and Antero overriding royalty interest of $53 million and $41 million respectively, both of which occurred in 2011. Additionally, CONSOL Energy incurred a $64 million loss on the Noble transaction during 2011.
- Interest Income increased $20 million due to the notes receivable which were part of the Noble joint venture transaction. See Note 2 - Acquisitions and Dispositions, in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- Revenue from equity affiliates increased $5 million due to the formation of CONE, a 50% affiliate. CONE was formed in relation to the Noble joint venture transaction. See Note 2 - Acquisitions and Dispositions, in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- The remaining $3 million increase relates to various transactions that occurred throughout both periods, none of which were individually material.

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 $39 million for the year ended December 31, 2012 compared to $59 million for the year ended December 31, 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 Years Ended December 31,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	18.0	16.4	1.6	9.8 %
Average Cost Per thousand cubic feet sold	$ 2.16	$ 3.61	$ (1.45)	(40.2)%

Purchased gas volumes represent volumes of gas purchased from third-party producers that are subsequently sold to customers. 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 $3 million for the year ended December 31, 2012 compared to $4 million for the year ended December 31, 2011.

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	1.1	1.2	(0.1)	(8.3)%
Average Cost Per thousand cubic feet sold	$ 2.44	$ 3.07	$ (0.63)	(20.5)%

Exploration and other costs were $39 million for the year ended December 31, 2012 compared to $18 million for the year ended December 31, 2011. The $21 million increase in costs is primarily related to the following items:

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Lease expiration costs	$18	$6	$12	200.0 %
Exploration	18	7	11	157.1 %
Dry Hole Costs	3	5	(2)	(40.0)%
Total Exploration and Other Costs	$39	$18	$21	116.7 %

- Lease Expiration costs increased $12 million primarily due to lease expirations relating to locations where CONSOL Energy allowed primary lease terms to expire. Additionally, the increase also relates to various title defect issues identified as part of the Noble transaction. See Note 2 - Acquisitions and Dispositions, in the Notes to the Audited Consolidated Financial Statements in Item 8 of this form 10-K for additional information.
- Exploration expenses increased $11 million due to increased exploratory expenses associated with the Utica operating area and various other transaction that occurred throughout both periods, none of which were individually material.
- Dry Hole Costs decreased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.

Other corporate expenses were $77 million for the year ended December 31, 2012 compared to $65 million for the year ended December 31, 2012. The $12 million increase in the period-to-period comparison was made up of the following items:

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Legal Fees	$5	$—	$5	100.0 %
PA Impact Fees	4	—	4	100.0 %
Unused FT Commitments	16	14	2	14.3 %
Short-Term Incentive Compensation	26	25	1	4.0 %
Stock Based Compensation	18	18	—	— %
Other	8	8	—	— %
Total Other Corporate Expenses	$77	$65	$12	18.5 %

- Legal fees were related to CNX Gas royalty litigation and title defect work. See Note 23 - Commitments and Contingencies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this form 10-K for additional information.
- 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.
- Unutilized firm transportation represents pipeline transportation capacity that the gas segment has obtained to enable gas production to flow uninterrupted as the gas operations continue to increase sales volumes.
- The short-term incentive compensation program is designed to increase compensation to eligible employees when CNX Gas reaches predetermined targets for safety compliance, production and unit costs. Short-term incentive compensation increased in the period-to-period comparison as the result of exceeding the targets in the 2012 period and an increased allocation of expense from CONSOL Energy as the result of exceeding corporate targets.
- Stock-based compensation remained consistent in the period-to-period comparison. Stock-based compensation costs are allocated to the gas segment based on revenue and capital expenditure projections between coal and gas.
- Other corporate related expense remained consistent in the period-to-period comparison.

Interest expense related to the other gas segment was $5 million for the year ended December 31, 2012 compared to $10 million for the year ended December 31, 2011. Interest expense was incurred by the other gas segment on the CNX Gas revolving credit facility and a capital lease. The $5 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 year ended December 31, 2011, the drilling services contract was bought out. Subsequent to this transaction, the noncontrolling interest was de-consolidated.

OTHER SEGMENT ANALYSIS for the year ended December 31, 2012 compared to the year ended December 31, 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 $198 million for the year ended December 31, 2012 compared to a loss before income tax of $275 million for the year ended December 31, 2011. The other segment also includes total company income tax expense of $109 million for the year ended December 31, 2012 compared to $155 million for the year ended December 31, 2011.

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Sales—Outside	$361	$346	$15	4.3 %
Other Income	20	16	4	25.0 %
Total Revenue	381	362	19	5.2 %
Cost of Goods Sold and Other Charges	329	368	(39)	(10.6)%
Depreciation, Depletion & Amortization	24	19	5	26.3 %
Taxes Other Than Income Tax	11	11	—	— %
Interest Expense	215	239	(24)	(10.0)%
Total Costs	579	637	(58)	(9.1)%
Loss Before Income Tax	(198)	(275)	77	28.0 %
Income Tax	109	155	(46)	(29.7)%
Net Loss	$(307)	$(430)	$123	28.6 %

Industrial supplies:

Total revenue from industrial supplies was $244 million for the year ended December 31, 2012 compared to $236 million for the year ended December 31, 2011. The increase was related to higher sales volumes.

Total costs related to industrial supply sales were $239 million for the year ended December 31, 2012 compared to $235 million for the year ended December 31, 2011. The increase of $4 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 $126 million for the year ended December 31, 2012 compared to $120 million for the year ended December 31, 2011. The increase of $6 million was primarily attributable to an increase in thru-put rates at the CNX Marine Terminal.

Total costs related to the transportation operations remained constant at $89 million for the year ended December 31, 2012 compared to the year ended December 31, 2011.

Miscellaneous other:

Additional other income of $11 million was recognized for the year ended December 31, 2012 compared to $6 million for the year ended December 31, 2011. The $5 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, transaction and financing fees and various other miscellaneous corporate charges. Total other costs were $251 million for the year ended December 31, 2012 compared to $313 million for the year ended December 31, 2011. Other corporate costs decreased due to the following items:

86

	For the Years Ended December 31,		
	2012	2011	Variance
Interest expense	$215	$239	$(24)
Loss on extinguishment of debt	—	16	(16)
Transaction and financing fees	—	15	(15)
Bank fees	13	18	(5)
Evaluation fees for non-core asset dispositions and other legal charges	4	6	(2)
Other	19	19	—
	$251	$313	$(62)

- Interest Expense decreased $24 million in the period-to-period comparison. Interest expense decreased due to an increase in capitalized interest related to higher capital expenditures for major construction projects in the current period. Capital expenditures for coal activities increased $310 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 year ended December 31, 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 $5 million mainly due to lower borrowings on the revolving credit facilities in the period-to-period comparison and also due to the refinancing and extension of the credit facility on April 12, 2011.
- Evaluation fees for non-core asset dispositions and other legal charges decreased $2 million in the period-to-period comparison due to various corporate initiatives.
- Various other corporate expenses remained constant in the period-to-period comparison.

Income Taxes:

The effective income tax rate was 22.0% for the year ended December 31, 2012 compared to 19.7% for the year ended December 31, 2011. The increase in the effective tax rate for the year ended December 31, 2012 compared to the year ended December 31, 2011 was primarily attributable to the gain on sale of CONSOL Energy's non-producing Northern Powder River Basin (PRB) assets and the gain on sale of CONSOL Energy's Ram River and Scurry Ram coal properties. The effective tax rate was also impacted by the relationship between the pre-tax earnings and percentage depletion. See Note 6—Income Taxes in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

	For the Years Ended December 31,			
	2012	2011	Variance	Percent Change
Total Company Earnings Before Income Tax	$497	$788	$(291)	(36.9)%
Income Tax Expense	$109	$155	$(46)	(29.7)%
Effective Income Tax Rate	22.0%	19.7%	2.3%	

Results of Operations
Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010

Net Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $632 million, or $2.76 per diluted share, for the year ended December 31, 2011. Net income attributable to CONSOL Energy shareholders was $347 million, or $1.60 per diluted share, for the year ended December 31, 2010.
The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $933 million of earnings before income tax for the year ended December 31, 2011 compared to $536 million for the year ended December 31, 2010. The total coal division sold 62.7 million tons of coal produced from CONSOL Energy mines, excluding our portion of tons sold from equity affiliates, for the year ended December 31, 2011 compared to 63.0 million tons for the year ended December 31, 2010.
The average sales price and average costs per ton for all active coal operations were as follows:

	For the Years Ended December 31,				
	2011	2010	Variance	Percent Change	
Average Sales Price per ton sold	$72.25	61.33	$10.92	17.8	%
Average Cost of Goods Sold per ton	50.69	45.74	4.95	10.8	%
Margin	$21.56	15.59	$5.97	38.3	%

The higher average sales price per ton sold reflects successful re-negotiation of several domestic thermal contracts whose pricing took effect January 1, 2011, another strong quarter of high volatile metallurgical coal sales and demand for our premium low volatile metallurgical coal. Also, 11.7 million tons were priced on the export market at an average sales price of $121.29 per ton for the year ended December 31, 2011 compared to 8.1 million tons at an average price of $97.10 per ton for the year ended December 31, 2010.

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

- Average operating supplies and maintenance costs per ton sold were higher due to increased equipment overhauls, additional roof control and additional equipment maintenance.
- Depreciation, depletion and amortization increased due to additional assets placed into service after the 2010 period.
- Labor and labor related charges increased as a result of additional employees, increased overtime hours worked and the impact of the $1.50 per hour worked UMWA contract wage increases, $0.50 per hour worked related to the prior UMWA contract and $1.00 per hour worked related to the July 2011 UMWA contract.
- Average retirement and disability costs per ton increased primarily due to changes in discount rates, employees retiring sooner than originally anticipated and higher average claim costs.
- Royalties and production taxes increased due to a higher average sales price per ton sold.

The total gas division includes coalbed methane (CBM), shallow oil and gas, Marcellus and other gas. The total gas division contributed $130 million of earnings before income tax for the year ended December 31, 2011 compared to $180 million for the year ended December 31, 2010. Total gas production was 153.5 billion net cubic feet for the year ended December 31, 2011 compared to 127.9 billion net cubic feet for the year ended December 31, 2010. Total gas production increased primarily due to the on-going drilling program partially offset by 6.6 billion net cubic feet of production related to the Noble joint venture.

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

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	$ 4.90	$ 5.83	$ (0.93)	(16.0)%
Average Costs per thousand cubic feet sold	3.53	3.54	(0.01)	(0.3)%
Margin	$ 1.37	$ 2.29	$ (0.92)	(40.2)%

Total gas division outside sales revenues were $752 million for the year ended December 31, 2011 compared to $746 million for the year ended December 31, 2010. The increase was primarily due to 20.0% increase in volumes sold partially offset by the 16.0% reduction in average price per thousand cubic feet sold. The volume increase was primarily due to additional wells drilled under the on-going drilling program, and additional volumes from the wells purchased in the Dominion Acquisition, which occurred on April 30, 2010 offset, in part, by the impact of the Noble joint venture which reduced 2011 volumes by approximately 6.6 billion net cubic feet. The decrease in average sales price is the result of various gas swap transactions that occurred throughout both periods and lower average market prices. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 84.0 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2011 at an average price of $5.21 per thousand cubic feet. These financial hedges represented 52.1 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2010 at an average price of $7.66 per thousand cubic feet.

Total gas unit costs decreased slightly for the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to lower depreciation, depletion and amortization and lower gathering costs partially offset by increased lifting costs. The wells purchased in the Dominion Acquisition increased total operating costs by $0.32 per thousand cubic feet due to higher costs and lower volumes produced related to the age of these wells compared to the legacy CONSOL Energy wells. Excluding the impact of these purchased wells, unit costs improved $0.36 per thousand cubic feet primarily due to the additional volumes produced, improved depreciation, depletion and amortization and lower gathering charges. Volumes increased in the period-to-period comparison due to the on-going drilling program and the additional volumes from the wells purchased in the Dominion Acquisition partially offset by the impact of the Noble joint venture. Lower depreciation, depletion and amortization rates were the result of additional gas reserves recognized at December 31, 2010. Gathering and compression charges were improved primarily due to a fuel surcharge reduction by a utility provider. Lifting costs increased in the period-to-period comparison due to additional well services to maintain production levels.

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 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 company general and administrative costs were made up of the following items:

For the Years Ended December 31,			
2011	2010	Variance	Percent Change

Employee wages and related expenses	$ 68	$ 60	$ 8	13.3	%
Contributions	15	11	4	36.4	%
Consulting and professional services	37	33	4	12.1	%
Miscellaneous	32	31	1	3.2	%
Total Company General and Administrative Expenses	$ 152	$ 135	$ 17	12.6	%

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

- Employee wages and related expenses increased $8 million which was primarily attributable to the support staff retained in the Dominion Acquisition and additional hiring of support staff in the period-to-period comparison.
- Contributions expense increased $4 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Consulting and professional services increased $4 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Miscellaneous general and administrative expenses increased $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Total Company long-term liabilities, such as other post employment benefits (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 calculated liabilities was $332 million for the year ended December 31, 2011 compared to $287 million for the year ended December 31, 2010. The increase of $45 million was due primarily to OPEB and salary pension expense. The additional OPEB and salary pension expense related to changes in discount rates, employees retiring sooner than originally anticipated and higher average claim costs. See Note 15—Pension and Other Postretirement Benefit Plans and Note 16—Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details related to total Company expense increases.

TOTAL COAL SEGMENT ANALYSIS for the year ended December 31, 2011 compared to the year ended December 31, 2010:

The coal segment contributed $933 million of earnings before income tax in the year ended December 31, 2011 compared to $536 million in the year ended December 31, 2010.

	For the Year Ended December 31, 2011					Difference to Year Ended December 31, 2010				
	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	$3,058	$368	$1,072	$27	$4,525	$57	$196	$392	$15	$660
Purchased Coal	—	—	—	42	42	—	—	—	8	8
Total Outside Sales	3,058	368	1,072	69	4,567	57	196	392	23	668
Freight Revenue	—	—	—	232	232	—	—	—	106	106
Other Income	6	11	—	62	79	(2)	4	—	14	16
Total Revenue and Other Income	3,064	379	1,072	363	4,878	55	200	392	143	790
Costs and Expenses:										
Beginning inventory costs	98	—	10	—	108	(56)	—	(10)	—	(66)
Total direct costs	1,543	142	219	152	2,056	25	88	45	46	204
Total royalty/production taxes	206	14	67	8	295	3	8	27	(80)	(42)
Total direct services to operations	248	30	22	251	551	13	18	5	(31)	5
Total retirement and disability	232	20	41	16	309	23	13	12	(8)	40
Depreciation, depletion and amortization	302	31	37	130	500	30	20	16	78	144
Ending inventory costs	(90)	—	(16)	—	(106)	8	—	(6)	—	2
Total Costs and Expenses	2,539	237	380	557	3,713	46	147	89	5	287
Freight Expense	—	—	—	232	232	—	—	—	106	106
Total Costs	2,539	237	380	789	3,945	46	147	89	111	393
Earnings (Loss) Before Income Taxes	$525	$142	$692	$(426)	$933	$9	$53	$303	$32	$397

THERMAL COAL SEGMENT

The thermal coal segment contributed $525 million to total Company earnings before income tax for the year ended December 31, 2011 compared to $516 million for the year ended December 31, 2010. The thermal coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Company Produced Thermal Tons Sold (in millions)	52.0	55.8	(3.8)	(6.8 %)
Average Sales Price Per Thermal Ton Sold	$58.87	$53.76	$5.11	9.5 %
Beginning Inventory Costs Per Thermal Ton	$51.73	$53.24	$(1.51)	(2.8 %)
Total Direct Operating Costs Per Thermal Ton Produced	$29.86	$27.62	$2.24	8.1 %
Total Royalty/Production Taxes Per Thermal Ton Produced	4.00	3.70	0.30	8.1 %
Total Direct Services to Operations Per Thermal Ton Produced	4.81	4.28	0.53	12.4 %
Total Retirement and Disability Per Thermal Ton Produced	4.48	3.80	0.68	17.9 %
Total Depreciation, Depletion and Amortization Costs Per Thermal Ton Produced	5.84	4.96	0.88	17.7 %
Total Production Costs Per Thermal Ton Produced	$48.99	$44.36	$4.63	10.4 %
Ending Inventory Costs Per Thermal Ton	$(58.32)	$(51.73)	$6.59	12.7 %
Total Costs Per Thermal Ton Sold	$48.88	$44.65	$4.23	9.5 %
Average Margin Per Thermal Ton Sold	$9.98	$9.11	$0.87	9.5 %

Thermal coal revenue was $3,058 million for the year ended December 31, 2011 compared to $3,001 million for the year ended December 31, 2010. The $57 million increase was attributable to a $5.11 per ton higher average sales price partially offset by 3.8 million fewer tons sold in 2011. The higher average thermal coal sales price in the 2011 period was the result of the successful re-negotiation of several domestic thermal contracts whose pricing took effect on January 1, 2011. Also, 2.8 million tons of thermal coal was priced on the export market at an average sales price of $66.45 per ton for the year ended December 31, 2011 compared to 2.4 million tons at an average price of $54.68 per ton for year ended December 31, 2010. The thermal coal segment was also impacted by 4.7 million tons of thermal coal sold on the high volatile metallurgical coal market for the year ended December 31, 2011, which was 2.3 million tons more than the tons sold in the year ended December 31, 2010.

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 cost of tons produced in the period. Total cost of goods for thermal coal was $2,539 million for the year ended December 31, 2011, or $46 million higher than the $2,493 million for the year ended December 31, 2010. Total costs of goods sold for thermal coal was $48.88 per ton in the year ended December 31, 2011 compared to $44.65 per ton in the year ended December 31, 2010. 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 $1,543 million in the year ended December 31, 2011 compared to $1,518 million in the year ended December 31, 2010. Direct operating costs were $29.86 per ton produced in the current period compared to $27.62 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 supplies and maintenance costs per thermal ton produced increased due to additional maintenance and equipment overhaul costs, additional roof control costs, and increased fuel and lubricants. Additional maintenance and equipment overhaul costs are related to additional equipment being serviced in the current period. Additional roof control costs resulted from changes in roof support strategy, such as using longer roof bolts and additional types of roof support, in order to improve the safety of our mines and to provide a more reliable source of production for our customers. Increased fuel and lubricant costs are related to higher fuel prices in the current period.

- Labor and related benefits were impaired on a cost per thermal ton sold basis due to higher costs and lower volumes sold. Higher benefit costs were due primarily to contributions made to the 1974 Pension Trust (the Trust), which is a multiemployer pension plan. Contributions to the Trust were negotiated under the National Bituminous Coal Wage Agreement and are based on a rate per hour worked by members of the United Mine Workers of America (UMWA). The contribution rate increased $0.50 per hour worked in the 2011 period compared to the 2010 period. Non-represented benefit rates for active employees also increased as a result of continued increases in healthcare costs. Labor and related benefits also increased due to additional employees and the impact of the wage increases of $1.50 per hour worked, $0.50 per hour worked effective January 1, 2011 under the previous collective bargaining agreement and $1.00 per hour worked effective July 1, 2011 related to the July 2011 collective bargaining agreement. These increases were offset, in part, as a result of the Tax Relief and Health Care Act of 2006 authorizing general fund revenues and expanding transfers of interest from the Abandoned Mine Land trust fund to cover orphan retirees which remain in the Combined Fund, the 1992 Benefit Plan and the 1993 Plan. The additional federal funding eliminated the 2011 funding of orphan retirees by participating active employers of the plans, resulting in lower expense in the period-to-period comparison. The additional federal funding does not impact the amount of contributions required to be paid for our assigned retirees. Also, we may be required to make additional payments in the future to these plans in the event the federal contributions are not sufficient to cover the benefits.
- Average operating costs per thermal ton sold increased due to lower tons sold resulting in fixed costs being allocated over less tons resulting in higher unit costs.

Royalties and production taxes increased $3 million to $206 million in the current year-to-date period. The impairment was primarily due to the $5.11 higher average sales price. Thermal coal royalties and production taxes were $4.00 per ton in the current year-to-date period compared to $3.70 per ton in the prior year-to-date period. Average cost per thermal 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 cost of these support services were $248 million in the current year-to-date period compared to $235 million in the prior year-to-date period. Direct services to the operations were $4.81 per ton in the current period compared to $4.28 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 which negatively impacted unit costs.
- 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.
- Unit costs were also impaired due to various other items, none of which were individually material.

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 thermal coal segment were $232 million for the year ended December 31, 2011 compared to $209 million for the year ended December 31, 2010. The increase in the thermal coal retirement and disability costs was primarily attributable to the total Company increase in long-term liability expense discussed in the total Company results of operations section.

Depreciation, depletion and amortization for the thermal coal segment was $302 million for the year ended December 31, 2011 compared to $272 million for the year ended December 31, 2010. The increase was primarily due to additional equipment and infrastructure placed into service after the 2010 period that was depreciated on a straight-line basis. The increase was also due to higher units-of-production rates for thermal coal mines due to additional air shafts being placed into service after the 2010 period which had higher unit rates than historical shafts put into service. These higher expenses and lower sales tons, resulted in a $0.88 increase in average costs per ton produced.

HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $142 million to total Company earnings before income tax for the year ended December 31, 2011 compared to $89 million for the year ended December 31, 2010. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Years Ended December 31,				
	2011	2010	Variance	Percent Change	
Company Produced High Vol Met Tons Sold (in millions)	4.7	2.4	2.3	95.8	%
Average Sales Price Per High Vol Met Ton Sold	$78.06	$72.89	$5.17	7.1	%
Beginning Inventory Costs Per High Vol Met Ton	$—	$—	$—	—	%
Total Direct Operating Costs Per High Vol Met Ton Produced	$30.15	$23.07	$7.08	30.7	%
Total Royalty/Production Taxes Per High Vol Met Ton Produced	3.01	2.40	0.61	25.4	%
Total Direct Services to Operations Per High Vol Met Ton Produced	6.26	5.19	1.07	20.6	%
Total Retirement and Disability Per High Vol Met Ton Produced	4.28	3.15	1.13	35.9	%
Total Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Produced	6.50	4.60	1.90	41.3	%
Total Production Costs Per High Vol Met Ton Produced	$50.20	$38.41	$11.79	30.7	%
Ending Inventory Costs Per High Vol Met Ton	$—	$—	$—	—	%
Total Costs Per High Vol Met Ton Sold	$50.20	$38.41	$11.79	30.7	%
Margin Per High Vol Met Ton Sold	$27.86	$34.48	$(6.62)	(19.2	%)

High volatile metallurgical coal revenue was $368 million for the year ended December 31, 2011 compared to $172 million for the year ended December 31, 2010. Strength in the metallurgical coal market continued to allow the export of Northern Appalachian coal, historically sold domestically on the thermal coal market, to crossover to the Brazilian and Asian metallurgical coal markets. Also, 4.3 million tons of thermal coal was priced on the export market at an average sales price of $77.48 per ton for the year ended December 31, 2011 compared to 2.3 million tons at an average price of $73.51 per ton for year ended December 31, 2010. As a result, average sales prices for high volatile metallurgical coal have increased due to growing the base of end user customers.

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

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 $237 million for the year ended December, 31 2011, or $147 million higher than the $90 million for the year ended December 31, 2010. Total cost of goods sold for high volatile metallurgical coal was $50.20 per ton in the year ended December 31, 2011 compared to $38.41 per ton in the year ended December 30, 2010. 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 $142 million in the year ended December 31, 2011 compared to $54 million in the year ended December 31, 2010. Direct operating costs were $30.15 per ton produced in the current period compared to $23.07 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 high volatile metallurgical ton produced increased due to the mix of mines selling coal on the high volatile metallurgical coal market. As higher cost structure mines sell coal in the high volatile metallurgical market, average operating costs per ton sold increase. Previously, this segment only included lower cost structure mines.

- Labor and related benefits increased due to higher employee counts, higher non-represented benefit rates and higher contributions per hour worked to the 1974 Pension Trust (Trust). Labor and related benefits increased due to additional employees in the period-to-period comparison. Higher labor and related costs were also due to higher non-represented benefit rates for active employees related to the continued increase in healthcare costs. Higher contributions made to the Trust were discussed in the thermal coal segment. Labor and related benefits also increased due to the impact of the wage increases of $1.50 per hour worked, $0.50 per hour worked effective January 1, 2011 under the previous collective bargaining agreement and $1.00 per hour worked effective July 1, 2011 related to the July 2011 collective bargaining agreement, in the period-to-period comparison. These increases were offset by lower overall contributions to certain multiemployer benefit plans such as the 1992 Fund, the 1993 Fund and the Combined Fund, which were also discussed in the thermal coal segment. Increased labor and related benefit costs per unit sold were also offset, in part, by additional volumes of high volatile metallurgical tons sold in the period-to-period comparison.
- Average operating supplies and maintenance costs per high volatile metallurgical ton produced increased due to additional maintenance and equipment overhaul costs, additional roof control costs, and increased fuel and lubricants. Additional maintenance and equipment overhaul costs are related to additional equipment being serviced in the current period. Additional roof control costs resulted from changes in roof support strategy, such as using longer roof bolts and additional types of roof support, in order to improve the safety of our mines and to provide a more reliable source of production for our customers.
- Average coal preparation costs per high volatile metallurgical ton produced increased due to additional maintenance projects that have been completed at our preparation plants in the period-to-period comparison.
- In-transit charges average cost per high volatile metallurgical ton produced increased primarily due to the increased cost of moving coal from the mine to the preparation plant for processing. This increase is primarily related to the mix of mines now shipping high volatile metallurgical coal.

Royalties and production taxes increased $8 million to $14 million in the current year-to-date period compared to $6 million in the prior year-to-date period. The impairment was primarily due to the $5.17 higher average sales price. High volatile metallurgical coal royalties and production taxes were $3.01 per ton in the current year-to-date period compared to $2.40 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 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 $30 million in the current year-to-date period compared to $12 million in the prior year-to-date period. Higher costs were attributable to more tons subject to commission expense, higher direct administrative costs, and higher subsidence costs. Direct services to the operations for high volatile metallurgical coal were $6.26 per ton in the current year-to-date period compared to $5.19 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 an increase in dollars spent and an increase in 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 retirement and disability costs attributable to the high volatile metallurgical coal segment were $20 million for the year ended December 31, 2011 compared to $7 million for the year ended December 31, 2010. The increase in the high volatile metallurgical coal provision expense was attributable to the total Company increase in long-term liability expense discussed in the total Company results of operations section.

Depreciation, depletion and amortization for the high volatile metallurgical coal segment was $31 million for the year ended December 31, 2011 compared to $11 million for the year ended December 31, 2010. The increase was primarily due to additional equipment and infrastructure placed into service after the 2010 period that is depreciated on a straight-line basis. The increase was also due to higher units-of-production rates for high volatile metallurgical coal mines related to additional air shafts being placed into service after the 2010 period which had higher unit rates than historical shafts put into service. These increases in unit costs per ton sold were offset, in part, by additional high volatile metallurgical tons sold which lowered the unit cost per ton impact.

The high volatile metallurgical coal segment increased the margin on our coal production that would have otherwise been sold in the domestic thermal coal market.

LOW VOL METALLURGICAL COAL SEGMENT

The low volatile metallurgical coal segment contributed $692 million to total Company earnings before income tax in the year ended December 31, 2011 compared to $389 million in the year ended December 31, 2010. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Company Produced Low Vol Met Tons Sold (in millions)	5.6	4.6	1.0	21.7 %
Average Sales Price Per Low Vol Met Ton Sold	$191.81	$146.32	$45.49	31.1 %
Beginning Inventory Costs Per Low Vol Met Ton	$62.51	$55.22	$7.29	13.2 %
Total Direct Operating Costs Per Low Vol Met Ton Produced	$38.71	$39.13	$(0.42)	(1.1%)
Total Royalty/Production Taxes Per Low Vol Met Ton Produced	11.74	9.03	2.71	30.0 %
Total Direct Services to Operations Per Low Vol Met Ton Produced	3.77	3.74	0.03	0.8 %
Total Retirement and Disability Per Low Vol Met Ton Produced	7.28	6.46	0.82	12.7 %
Total Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Produced	6.54	4.78	1.76	36.8 %
Total Production Costs Per Low Vol Met Ton Produced	$68.04	$63.14	$4.90	7.8 %
Ending Inventory Costs Per Low Vol Met Ton	$(67.60)	$(62.51)	$(5.09)	8.1 %
Total Costs Per Low Vol Met Ton Sold	$67.90	$62.55	$5.35	8.6 %
Margin Per Low Vol Met Ton Sold	$123.91	$83.77	$40.14	47.9 %

Low volatile metallurgical coal revenue was $1,072 million for the year ended December 31, 2011 compared to $680 million for the year ended December 31, 2010. The $392 million increase was attributable to a $45.49 per ton higher average sales price due to the strength of the low volatile metallurgical market, both domestic and foreign. The strength of these markets is related to continued worldwide demand for premium low volatile metallurgical coal. For the 2011 period, 4.6 million tons of low volatile metallurgical coal was priced on the export market at an average price of $196.46 per ton compared to 3.3 million tons at an average price of $144.23 per ton for the 2010 period.

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 $380 million for the year ended December 31, 2011, or $89 million higher than the $291 million for the year ended December 31, 2010. Total cost of goods sold for low volatile metallurgical coal was $67.90 per ton in the year ended December 31, 2011 compared to $62.55 per ton in the year ended December 31, 2010. 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 $219 million in the year ended December 31, 2011 compared to $174 million in the year ended December 31, 2010. Direct operating costs were $38.71 per ton produced in the current year-to-date period compared to $39.13 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:

- Average operating supplies and maintenance costs per low volatile metallurgical ton produced increased due to additional roof control costs, additional ventilation costs of coalbed methane gas, additional equipment overhaul costs and increased rock dusting. Additional roof control costs resulted from changes in roof support strategy, such as types of roof support used and quantity of supports put into place. The roof control strategy was changed to improve the safety of the mine and to provide a more reliable source of production for our customers. Roof control costs also increased due to higher steel prices in the period-to-period comparison. In addition, costs were incurred in the 2011 period to increase the number of bore holes that were placed ahead of mining to ventilate the coalbed methane gas from the mine. Additional maintenance and equipment overhaul costs are related to additional equipment being serviced in the current period. Increased rock dusting was primarily due to changes in regulations.

- These increases in costs were partially offset by a decrease in the power costs per low volatile metallurgical ton produced which were improved due to utility rate reductions that became effective in the 2011 period.

Royalties and production taxes increased $27 million to $67 million in the current year-to-date period compared to $40 million in the prior year-to-date period. The impairment was primarily due to the $45.49 higher average sales price. Unit costs also increased $2.71 per low volatile metallurgical ton produced to $11.74 per ton in the current year-to-date period compared to $9.03 per ton in the prior year-to-date period. Average cost per low 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 low volatile metallurgical coal were $22 million in the current year-to-date period compared to $17 million in the prior year-to-date period. Direct services to the operations for low volatile metallurgical coal were $3.77 per ton in the current year-to-date period compared to $3.74 per ton in the prior year-to-date period. The cost increase is primarily due to a reverse osmosis plant that was completed and placed into service near the Buchanan Mine. Active mine water discharge is being treated by this facility and the costs of these services are charged to the mine based on gallons of water treated. Currently, the Buchanan Mine is the only facility utilizing the plant. Construction of the plant was completed and the plant was placed in service in January 2011.
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 $41 million for the year ended December 31, 2011 compared to $29 million for the year ended December 31, 2010. The increase in the low volatile metallurgical coal provision expense was attributable to the total Company's increased long-term liability expense discussed in the total Company results of operations section, offset, in part, by higher volumes of low volatile metallurgical coal sold.

Depreciation, depletion and amortization for the low volatile metallurgical coal segment was $37 million for the year ended December 31, 2011 compared to $21 million for the year ended December 31, 2010. The increase was primarily due to additional equipment, infrastructure and the reverse osmosis plant placed into service after the 2010 period that is depreciated on a straight-line basis. These increases in average costs per ton sold were offset, in part, by higher low volatile metallurgical tons sold which lowered the unit cost per ton impact.

OTHER COAL SEGMENT
The other coal segment had a loss before income tax of $426 million for the year ended December 31, 2011 compared to a loss before income tax of $458 million for the year ended December 31, 2010. 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.
The other coal segment produced coal sales includes revenue from the sale of 0.4 million tons of coal which was recovered during the reclamation process at idled facilities for the year ended December 31, 2011 compared to 0.2 million tons for the year ended December 31, 2010. The primary focus of the activity at these locations is reclaiming disturbed land in accordance with the mining permit requirements after final mining has occurred. The tons sold are

incidental to total Company production or sales.

Purchased coal sales consist of revenues from processing third-party coal in our preparation plants for blending purposes to meet customer coal specifications, coal purchased from third parties and sold directly to our customers and revenues from processing third-party coal in our preparation plants. The revenues were $42 million for the year ended December 31, 2011 compared to $34 million for the year ended December 31, 2010. The increase was primarily due to increased volumes sold partially offset by a decrease in the average sales price.

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 almost completely offset in freight expense. Freight revenue was $232 million for the year ended December 31, 2011 compared to $126 million for the year ended December 31, 2010. The increase in freight revenue was primarily due to the 3.6 million ton increase in export tons in the period-to-period comparison.

Miscellaneous other income was $62 million for the year ended December 31, 2011 compared to $48 million for the year ended December 31, 2010. The increase of $14 million was primarily related to issuing pipeline right-of-ways to third parties which resulted in a gain of $12 million and various other transactions that occurred throughout both periods, none of which were individually material.

Other coal segment total costs were $789 million for the year ended December 31, 2011 compared to $678 million for the year ended December 31, 2010. The increase of $111 million was due to the following items:

	For the Years Ended December 31,		
	2011	2010	Variance
Abandonment of long-lived assets	$116	$—	$116
Freight expense	231	126	105
Purchased Coal	71	40	31
General and Administrative Expense	98	83	15
Litigation Contingencies	8	55	(47)
Closed and idle mines	107	222	(115)
Other	158	152	6
Total other coal segment costs	$789	$678	$111

- Abandonment of long-lived assets was $116 million for the year ended December 31, 2011 as a result of permanently idling 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 almost completely offset in freight revenue. The increase was primarily due to the 3.6 million ton increase in export tons in the period-to-period comparison.
- Purchased coal costs increased approximately $31 million in the period-to-period comparison primarily due to differences in the quality of coal purchased, increases in the market price of coal purchased, and an increase in the volumes of coal purchased in the period-to-period comparison.
- General and Administrative Expense related to the other coal segment increased by $15 million primarily due to an increase of wages and related expenses and professional services.
- Litigation expense of $25 million was recognized in the year ended December 31, 2010 related to a legal settlement related to water discharge from our Buchanan Mine being stored in mine voids of adjacent properties which were leased by CONSOL Energy subsidiaries. Litigation expense was also recognized in the year ended December 31, 2010 related to a settlement that included the sale of Jones Fork which resulted in a loss of $10 million. Litigation expense related to various other potential legal settlements decreased $12 million in the period-to-period comparison. None of these items were individually material.
- General and Administrative Expense related to the other coal segment increased by $15 million primarily due to an increase of wages and related expenses.
- Closed and idle mine costs decreased approximately $115 million in the year ended December 31, 2011 compared to the year ended December 31, 2010. In the 2010 period, as a result of market conditions, permitting issues, new regulatory requirements and the resulting changes in mining plans, the reclamation liability associated with the Fola mining operations in West Virginia increased $82 million. Also in the 2010 period, closed and idle mine costs increased approximately $14 million as the result of the change in mine plan at Mine 84. As a result of the mine plan change, a portion of the previously developed area of the mine was abandoned. Closed and idle mine costs decreased $9 million as a result of the decision to permanently abandon Mine 84. Closed and idle mine costs for the 2010 period also included $6 million related to various

asset abandonments that occurred, none of which were individually material. In addition, $9 million of reduced expenses were recognized in closed and idle mine costs for various changes in the operational status of other mines, between idled and operating, throughout both periods, none of which were individually material. Closed and idle mine costs increased $5 million in the 2011 period due to a charge for an additional liability due to Pennsylvania stream remediation.

- Other costs related to the coal segment increased $6 million due to various other transactions that occurred throughout both periods, none of which are individually material.

TOTAL GAS SEGMENT ANALYSIS for the year ended December 31, 2011 compared to the year ended December 31, 2010:

The gas segment contributed $130 million to earnings before income tax for the year ended December 31, 2011 compared to $180 million for the year ended December 31, 2010.

	For the Year Ended December 31, 2011					Difference to Year Ended December 31, 2010				
	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$461	$155	$119	$12	$747	$(106)	$39	$70	$4	$7
Related Party	5	—	—	—	5	(1)	—	—	—	(1)
Total Outside Sales	466	155	119	12	752	(107)	39	70	4	6
Gas Royalty Interest	—	—	—	67	67	—	—	—	4	4
Purchased Gas	—	—	—	4	4	—	—	—	(7)	(7)
Other Income	—	—	—	59	59	—	—	—	54	54
Total Revenue and Other Income	466	155	119	142	882	(107)	39	70	55	57
Lifting	40	49	15	1	105	2	28	10	—	40
Ad Valorem, Severance, and Other Taxes	12	12	1	1	26	(1)	2	—	1	2
Gathering	98	27	15	2	142	1	9	5	(1)	14
Gas Direct Administrative, Selling & Other	29	21	11	—	61	(2)	9	8	—	15
Depreciation, Depletion and Amortization	101	61	35	10	207	(12)	11	15	3	17
General & Administration	—	—	—	51	51	—	—	—	6	6
Gas Royalty Interest	—	—	—	59	59	—	—	—	5	5
Purchased Gas	—	—	—	4	4	—	—	—	(6)	(6)
Exploration and Other Costs	—	—	—	18	18	—	—	—	(7)	(7)
Other Corporate Expenses	—	—	—	65	65	—	—	—	9	9
Interest Expense	—	—	—	10	10	—	—	—	3	3
Total Cost	280	170	77	221	748	(12)	59	38	13	98
Earnings Before Noncontrolling Interest and Income	186	(15)	42	(79)	134	(95)	(20)	32	42	(41)

Tax										
Noncontrolling Interest	—	—	—	4	4	—	—	—	9	9
Earnings Before Income Tax	$186	$(15)	$42	$(83)	$130	$(95)	$(20)	$32	$33	$(50)

99

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $186 million to the total Company earnings before income tax for the year ended December 31, 2011 compared to $281 million for the year ended December 31, 2010.

	For the Years Ended December 31,					
	2011	2010	Variance		Percent Change	
Produced gas CBM sales volumes (in billion cubic feet)	92.4	91.4	1.0		1.1	%
Average CBM sales price per thousand cubic feet sold	$5.05	$6.27	$(1.22	)	(19.5	)%
Average CBM lifting costs per thousand cubic feet sold	$0.43	$0.42	$0.01		2.4	%
Average CBM ad valorem, severance, and other taxes per thousand cubic feet sold	$0.13	$0.14	$(0.01	)	(7.1	)%
Average CBM gathering costs per thousand cubic feet sold	$1.06	$1.06	$—		—	%
Average CBM direct administrative, selling, & other costs per thousand cubic feet sold	$0.31	$0.34	$(0.03	)	(8.8	)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	$1.10	$1.24	$(0.14	)	(11.3	)%
Total Average CBM costs per thousand cubic feet sold	$3.03	$3.20	$(0.17	)	(5.3	)%
Average Margin for CBM	$2.02	$3.07	$(1.05	)	(34.2	)%

CBM sales revenues were $466 million for the year ended December 31, 2011 compared to $573 million for the year ended December 31, 2010. The $107 million decrease was primarily due to a 19.5% decrease in average sales price per thousand cubic feet sold, offset, in part, by a 1.1% increase in average volumes sold. The decrease in CBM average sales price is the result of various gas swap transactions that matured in each period and lower average market prices. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 61.8 billion cubic feet of our produced CBM gas sales volumes for the year ended December 31, 2011 at an average price of $5.36 per thousand cubic feet. For the year ended December 31, 2010, these financial hedges represented 50.5 billion cubic feet at an average price of $7.73 per thousand cubic feet. CBM sales volumes increased 1.0 billion cubic feet primarily due to additional wells coming on-line from our on-going drilling program.

Total costs for the CBM segment were $280 million for the year ended December 31, 2011 compared to $292 million for the year ended December 31, 2010. Lower costs in the period-to-period comparison are primarily related to lower unit costs.

CBM lifting costs were $40 million for the year ended December 31, 2011 compared to $38 million for the year ended December 31, 2010. Lifting costs increased primarily due to increased road maintenance, additional tank repairs, and additional maintenance on older wells.

CBM gathering costs were $98 million for the year ended December 31, 2011 compared to $97 million for the year ended December 31, 2010. CBM gathering unit costs remained consistent in the period-to-period comparison.

CBM direct administrative, selling & other costs were $29 million for year ended December 31, 2011 compared to $31 million for the year ended December 31, 2010. 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 attributable to the CBM segment was attributable to the increase in other gas segment volumes.

Depreciation, depletion and amortization attributable to the CBM segment was $101 million for the year ended December 31, 2011 compared to $113 million for the year ended December 31, 2010. There was approximately $72 million, or $0.78 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 year ended December 31, 2011. The production portion of depreciation, depletion and amortization was $87 million, or $0.98 per unit-of-production in the year ended December 31, 2010. The CBM unit-of-production rate decreased due to revised rates which are generally calculated using the net book value of assets divided by either proved or proved developed reserve additions. There was approximately $29 million, or $0.32 average per unit cost of depreciation, depletion and amortization relating to gathering and other equipment reflected on a straight line basis for the year ended December 31, 2011. The non-production related depreciation, depletion and amortization was $26 million, or $0.27 per thousand cubic feet for the year ended December 31, 2010. The increase was related to additional gathering assets placed in service after the 2010 period.

SHALLOW OIL AND GAS SEGMENT

The Shallow Oil and Gas segment had a loss before income tax of $15 million for the year ended December 31, 2011 compared to a gain before income tax of $5 million for the year ended December 31, 2010.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Produced gas Shallow Oil and Gas sales volumes (in billion cubic feet)	32.2	24.7	7.5	30.4 %
Average Shallow Oil and Gas sales price per thousand cubic feet sold	$4.83	$4.73	$0.10	2.1 %
Average Shallow Oil and Gas lifting costs per thousand cubic feet sold	$1.52	$0.86	$0.66	76.7 %
Average Shallow Oil and Gas ad valorem, severance, and other taxes per thousand cubic feet sold	$0.37	$0.40	$(0.03)	(7.5)%
Average Shallow Oil and Gas gathering costs per thousand cubic feet sold	$0.83	$0.75	$0.08	10.7 %
Average Shallow Oil and Gas direct administrative, selling, & other costs per thousand cubic feet sold	$0.67	$0.49	$0.18	36.7 %
Average Shallow Oil and Gas depreciation, depletion and amortization costs per thousand cubic feet sold	$1.90	$2.04	$(0.14)	(6.9)%
Total Average Shallow Oil and Gas costs per thousand cubic feet sold	$5.29	$4.54	$0.75	16.5 %
Average Margin for Shallow Oil and Gas	$(0.46)	$0.19	$(0.65)	(342.1)%

Shallow Oil and Gas sales revenues were $155 million for the year ended December 31, 2011 compared to $116 million for the year ended December 31, 2010. The $39 million increase was primarily due to the 30.4% increase in volumes sold as well as the 2.1% increase in average sales price. Shallow Oil and Gas sales volumes increased 7.5 billion cubic feet in the year ended December 31, 2011 compared to the 2010 period primarily due to the Dominion Acquisition, which closed on April 30, 2010. Approximately 95% of the acquired producing wells were Shallow Oil and Gas type wells. Average sales price increased primarily as the result of various gas swap transactions that matured in the year ended December 31 2011, offset, in part by lower average market prices. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 11.5 billion cubic feet of our produced Shallow Oil and Gas gas sales volumes for the year ended December 31, 2011 at an average price of $4.97 per thousand cubic feet. There were no Shallow Oil and Gas gas swap transactions that occurred in the year ended December 31, 2010.

Shallow Oil and Gas lifting costs were $49 million for the year ended December 31, 2011 compared to $21 million for the year ended December 31, 2010. Lifting costs per unit increased $0.66 per thousand cubic feet sold primarily due to increased road maintenance, increased well site maintenance, increased salt water disposal and additional well services performed to maintain production levels.

Shallow Oil and Gas gathering costs were $27 million for the year ended December 31, 2011 compared to $18 million for the year ended December 31, 2010. Average gathering costs increased $0.08 per unit primarily due to additional compressor maintenance.

Shallow Oil and Gas direct administrative, selling and other costs were $21 million for the year ended December 31, 2011 compared to $12 million for the year ended December 31, 2010. Direct administrative, selling and other costs are allocated to the individual gas segments based on a combination of production and employee counts. The $9 million increase in the period-to-period comparison is due to increased direct administrative labor and Shallow Oil and Gas volumes representing a smaller proportion of total natural gas volumes.

Depreciation, depletion and amortization costs were $61 million for the year ended December 31, 2011 compared to $50 million for the year ended December 31, 2010. There was approximately $54 million, or $1.69 per unit-of-production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation in the year ended December 31, 2011. There was approximately $45 million, or $1.84 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 year ended December 31, 2010. 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 $7 million, or $0.23 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 year ended December 31, 2011. There was $5 million, or $0.19 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the year ended December 31, 2010. The increase was related to additional infrastructure and equipment placed in service after the 2010 period.

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $42 million to the total Company earnings before income tax for the year ended December 31, 2011 compared to $10 million for the year ended December 31, 2010.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Produced gas Marcellus sales volumes (in billion cubic feet)	26.9	10.4	16.5	158.7 %
Average Marcellus sales price per thousand cubic feet sold	$4.43	$4.69	$(0.26)	(5.5)%
Average Marcellus lifting costs per thousand cubic feet sold	$0.56	$0.45	$0.11	24.4 %
Average Marcellus ad valorem, severance, and other taxes per thousand cubic feet sold	$0.05	$0.05	$—	— %
Average Marcellus gathering costs per thousand cubic feet sold	$0.54	$0.99	$(0.45)	(45.5)%
Average Marcellus direct administrative, selling & other costs per thousand cubic feet sold	$0.41	$0.37	$0.04	10.8 %
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	$1.33	$1.90	$(0.57)	(30.0)%
Total Average Marcellus costs per thousand cubic feet sold	$2.89	$3.76	$(0.87)	(23.1)%
Average Margin for Marcellus	$1.54	$0.93	$0.61	65.6 %

The Marcellus segment sales revenues were $119 million for the year ended December 31, 2011 compared to $49 million for the year ended December 31, 2010. The $70 million increase was primarily due to a 158.7% increase in average volumes sold, offset, in part, by a 5.5% decrease in average sales price per thousand cubic feet sold. The increase in sales volumes is primarily due to additional wells coming on-line from our on-going drilling program, partially offset by 6.6 billion cubic feet related to the Noble joint venture and 1.0 billion cubic feet related to the Antero sale. The decrease in Marcellus average sales price was the result of the decline in general market prices. These decreases were offset, in part, by various gas swap transactions that matured in the year ended December 31, 2011. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These hedges represented approximately 10.6 billion cubic feet of our produced Marcellus gas sales volumes for the year ended December 31, 2011 at an average price of $4.64 per thousand cubic feet. For the year ended December 31, 2010, these financial hedges represented 1.6 billion cubic feet at an average price of $5.05 per thousand cubic feet.

Marcellus lifting costs were $15 million for the year ended December 31, 2011 compared to $5 million for the year ended December 31, 2010. Lifting costs per unit increased $0.11 per thousand cubic feet sold primarily due to increased expenses for well clean out and tubing replacement services performed to improve production.

Marcellus gathering costs were $15 million for the year ended December 31, 2011 compared to $10 million for the year ended December 31, 2010. Average gathering costs decreased $0.45 per unit primarily due to the 16.5 billion cubic feet of additional volumes sold.

Marcellus direct administrative, selling & other costs were $11 million for the year ended December 31, 2011 compared to $3 million for the year ended December 31, 2010. 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 $35 million for the year ended December 31, 2011 compared to $20 million for the year ended December 31, 2010. There was approximately $27 million, or $1.04 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 year ended December 31, 2011. There was approximately $18 million, or $1.72 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 year ended December 31, 2010. 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 $8 million, or $0.28 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 year ended December 31, 2011. There was $2 million, or $0.18 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the year ended December 31, 2010. The increase was related to additional infrastructure and equipment placed in service after the 2010 period.

OTHER GAS SEGMENT

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

Other gas sales volumes are primarily related to production from the Chattanooga Shale in Tennessee. Revenue from this operation was approximately $12 million for the year ended December 31, 2011 and $8 million for the year ended December 31, 2010. Total costs related to these other sales were $14 million for the 2011 period and were $10 million for the 2010 period. The increase in costs in the period-to-period comparison were primarily attributable to increased general and direct administrative costs allocated to the other gas segment and increased depreciation, depletion and amortization. Higher general and direct administrative costs were attributable to the total gas increase as discussed in the CBM segment coupled with increased sales volumes. Higher depreciation, depletion and amortization was due to higher volumes produced and higher unit of production rates. A per unit analysis of the other operating costs in the Chattanooga shale is not meaningful due to the low volumes produced in the period-to-period analysis.

Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas division. Royalty interest gas sales revenue was $67 million for the year ended December 31, 2011 compared to $63 million for the year ended December 31, 2010. 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 Years Ended December 31,			
	2011	2010	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	16.4	14.2	2.2	15.5 %
Average Sales Price Per thousand cubic feet	$4.07	$4.41	$(0.34)	(7.7)%

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $4 million for the year ended December 31, 2011 compared to $11 million for the year ended December 31, 2010.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	1.0	2.0	(1.0)	(50.0)%
Average Sales Price Per thousand cubic feet	$4.28	$5.48	$(1.20)	(21.9)%

Other income was $59 million for the year ended December 31, 2011 compared to $5 million for the year ended December 31, 2010. The $54 million increase was primarily due to a gain on the Hess transaction of $53 million, a gain on the sale of the Antero overriding royalty interest of $41 million, $8 million of additional interest income related to the notes receivable related to the Noble joint venture transaction, $5 million due to various transactions that occurred throughout both periods, none of which were individually material and $4 million due to increased earnings from equity affiliates. These improvements were partially offset by a loss on the Noble transaction of $57 million.

General and administrative costs are allocated to the total gas segment based on a percentage of total revenue and a percentage of total projected capital expenditures. Costs were $51 million for the year ended December 31, 2011 compared to $45 million for the year ended December 31, 2010. Refer to the discussion of total general and administrative costs contained in the section "Net Income" of this annual 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 $59 million for the year ended December 31, 2011 compared to $54 million for the year ended December 31, 2010. 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 Years Ended December 31,			
	2011	2010	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	16.4	14.2	2.2	15.5 %
Average Cost Per thousand cubic feet sold	$3.61	$3.78	$(0.17)	(4.5)%

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 $4 million for the year ended December 31, 2011 compared to $10 million for the year ended December 31, 2010.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	1.2	1.9	(0.7)	(36.8)%
Average Cost Per thousand cubic feet sold	$3.07	$5.14	$(2.07)	(40.3)%

Exploration and other costs were $18 million for the year ended December 31, 2011 compared to $25 million for the year ended December 31, 2010. The $7 million decrease in costs is primarily related to a favorable settlement involving defective pipe which reduced expense in the 2011 period and lower dry hole and lease surrender costs in the 2011 period. Costs included in the exploration and other cost line are detailed as follows:

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Dry hole and lease expiration costs	$11	$21	$(10)	(47.6)%
Exploration	7	4	3	75.0 %
Total Exploration and Other Costs	$18	$25	$(7)	(28.0)%

Other corporate expenses were $65 million for the year ended December 31, 2011 compared to $56 million for the year ended December 31, 2010. The $9 million increase in the period-to-period comparison was made up of the following items:

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Unutilized firm transportation	$14	$3	$11	366.7 %
Contract buyout	3	—	3	100.0 %
Bank fees	7	4	3	75.0 %
Stock-based compensation	18	16	2	12.5 %
Short-term incentive compensation	25	24	1	4.2 %
Variable interest earnings	(4)	4	(8)	(200.0)%
Legal fees	—	3	(3)	(100.0)%
Other	2	2	—	— %

Total Other Corporate Expenses	$65	$56	$9	16.1	%

- Unutilized firm transportation represents pipeline transportation capacity that the gas segment has obtained to enable gas production to flow uninterrupted as the gas operations continue to increase sales volumes.
- Contract buyout represents the cancellation of a drilling arrangement with a third party well driller.
- Bank fees were higher in the period-to-period comparison due to amending and extending the revolving credit facility related to the gas segment. In April 2011, the facility was amended to allow $1 billion of borrowings and was extended to April 12, 2016.
- Stock-based compensation was higher in the period-to-period comparison primarily due to the increased allocation from CONSOL Energy as a result of the Dominion Acquisition as well as 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 increased in the period-to-period comparison as the result of exceeding the targets in the 2011 period, increased number of employees, and an increased allocation of expense from CONSOL Energy as the result of exceeding corporate targets.
- Variable interest earnings are related to various adjustments a third party entity has reflected in its financial statements. CONSOL Energy holds no ownership interest and during the 2011 period de-consolidated the impact of this third party due to the cancellation of the drilling arrangement. Based on analysis, during the time CONSOL Energy guaranteed the bank loans the entity held, it was determined that CONSOL Energy was the primary beneficiary. Therefore, the entity was fully consolidated and the earnings impact was fully reversed in the non-controlling interest line discussed below.
- Legal fees for the 2010 period were related to the special committee formed during the CNX Gas take-in transaction and also represent legal fees related to the shareholder litigation related to this transaction.
- Other corporate related expense remained consistent in the period-to-period comparison.

Interest expense related to the other gas segment was $10 million for the year ended December 31, 2011 compared to $7 million for the year ended December 31, 2010. Interest was incurred by the other gas segment on the CNX Gas revolving credit facility, a capital lease and debt held by a variable interest entity. The $3 million increase was primarily due to higher 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 which has been determined to be a variable interest entity, in which CONSOL Energy held no ownership interest, but was the primary beneficiary. The CONSOL Energy gas division was determined to be the primary beneficiary due to guarantees of the third party's bank debt related to their purchase of drilling rigs. The third-party entity provides drilling services primarily to the CONSOL Energy gas division. CONSOL Energy consolidates the entity and then reflects 100% of the impact as noncontrolling interest. The consolidation did not significantly impact any amounts reflected in the gas division income statement. The variance in the noncontrolling amounts reflects the third party's variance in earnings in the period-to-period comparison. In the year ended December 31, 2011, the drilling services contract was bought out. Subsequent to this transaction, the noncontrolling interest was de-consolidated.

OTHER SEGMENT ANALYSIS for the year ended December 31, 2011 compared to the year ended December 31, 2010:

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 $275 million for the year ended December 31, 2011 compared to a loss before income tax of $249 million for the year ended December 31, 2010. The other segment also includes total company income tax expense of $155 million for the year ended December 31, 2011 compared to $109 million for the year ended December 31, 2010.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Sales—Outside	$346	$297	$49	16.5 %
Other Income	16	29	(13)	(44.8)%
Total Revenue	362	326	36	11.0 %
Cost of Goods Sold and Other Charges	368	349	19	5.4 %
Depreciation, Depletion & Amortization	19	18	1	5.6 %
Taxes Other Than Income Tax	11	10	1	10.0 %
Interest Expense	239	198	41	20.7 %
Total Costs	637	575	62	10.8 %
Loss Before Income Tax	(275)	(249)	(26)	(10.4)%
Income Tax	155	109	46	42.2 %
Net Loss	$(430)	$(358)	$(72)	(20.1)%

Industrial supplies:

Total revenue from industrial supplies was $236 million for the year ended December 31, 2011 compared to $195 million for the year ended December 31, 2010. The increase was related to higher sales volumes.

Total costs related to industrial supply sales were $235 million for the year ended December 31, 2011 compared to $197 million for the year ended December 31, 2010. The increase of $38 million was primarily related to higher sales volumes and changes in last-in, first-out inventory valuations.

Transportation operations:

Total revenue from transportation operations was $120 million for the year ended December 31, 2011 compared to $114 million for the year ended December 31, 2010. The increase of $6 million was primarily attributable to additional through-put tons at the Baltimore terminal in the period-to-period comparison.

Total costs related to the transportation operations were $89 million for the year ended December 31, 2011 compared to $81 million for the year ended December 31, 2010. The increase of $8 million was related to the additional through-put tons handled by the operations and additional repairs and maintenance costs to maintain the Baltimore terminal facilities.

Miscellaneous other:

Additional other income of $6 million was recognized for the year ended December 31, 2011 compared to $17 million for the year ended December 31, 2010. The $11 million decrease was primarily due to $5 million related to the 2010 successful resolution of an outstanding tax issue with the Canadian Revenue Authority for the years 1997 through 2003 in which CONSOL Energy was entitled to interest on a tax refund, $2 million lower equity in earnings of affiliates in the current period compared to the prior year period and $4 million related to various transactions that have occurred throughout both periods, none of which were individually material.

Other corporate costs in the other segment include interest expense, transaction and financing fees and various other miscellaneous corporate charges. Total other costs were $313 million for the year ended December 31, 2011 compared to $297 million for the year ended December 31, 2010. Other corporate costs increased due to the following items:

	For the Years Ended December 31,		
	2011	2010	Variance
Interest expense	$239	$198	$41
Loss on extinguishment of debt	16	—	16
Evaluation fees for non-core asset dispositions	6	2	4
Bank fees	18	16	2
Transaction and financing fees	15	61	(46)
Other	19	20	(1)
	$313	$297	$16

- Interest expense increased $41 million primarily due to interest expense on the long-term bonds that were issued in conjunction with the Dominion Acquisition in April 2010.
- 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 redemption price included principal of $250 million, a make-whole premium of $16 million and accrued interest of $2 million for a total redemption cost of $268 million. 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.
- Evaluation fees for non-core asset dispositions increased $4 million in the period-to-period comparison due to various corporate initiatives that began in the 2010 period.
- Bank fees increased $2 million in the period-to-period comparison due to the refinancing and extension of the previous $1.0 billion credit facility to $1.5 billion on April 12, 2011.
- Transaction and financing fees of $15 million were incurred in the year ended December 31, 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 CONSOL Energy's oil and gas properties. Transaction and financing fees of $61 million were incurred in the year ended December 31, 2010 primarily related to the Dominion Acquisition, as well as the equity and debt issuance that raised approximately $4.6 billion.
- Various other corporate expenses were $19 million in the year ended December 31, 2011 compared to $20 million in the year ended December 31, 2010. The decrease of $1 million was due to various transactions that occurred throughout both periods, none of which were individually material.

Income Taxes:

The effective income tax rate was 19.7% for the year ended December 31, 2011 compared to 23.4% for the year ended December 31, 2010. The decrease in the effective tax rate for the year ended December 31, 2011 as compared to the year ended December 31, 2010 was primarily attributable to various discrete transactions that occurred in both periods. The discrete transactions included an Internal Revenue Service audit settlement for years 2006 and 2007 and the corresponding impacts to the previously accrued tax positions which resulted in higher percentage depletion deductions. Discrete transactions also included the reversal of a valuation allowance for certain state net operating loss carryforwards and future temporary deductions as well as the reversal of certain uncertain tax positions. See Note 6—Income Taxes in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Total Company Earnings Before Income Tax	$788	$468	$320	68.4%
Income Tax Expense	$155	$109	$46	42.2%
Effective Income Tax Rate	19.7%	23.4%	(3.7)%	

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make judgments, estimates and assumptions that affect reported amounts of assets and liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities in the consolidated financial statements and at the date of the financial statements. See Note 1-Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion. On an on-going basis, we evaluate our estimates. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making the judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from those estimates upon subsequent resolution of identified matters. Management believes that the estimates utilized are reasonable. The following critical accounting policies are materially impacted by judgments, assumptions and estimates used in the preparation of the Consolidated Financial Statements.

Other Post Employment Benefits (OPEB)

Certain subsidiaries of CONSOL Energy provide medical and life insurance benefits to retired employees not covered by the Coal Industry Retiree Health Benefit Act of 1992. The medical plans contain certain cost sharing and containment features, such as deductibles, coinsurance, health care networks and coordination with Medicare. For salaried or non-represented hourly employees hired before January 1, 2007, the eligibility requirement is either age 55 with 20 years of service or age 62 with 15 years of service. Also, salaried employees and retirees contribute a target of 20% of the medical plan operating costs. Contributions may be higher, dependent on either years of service or a combination of age and years of service at retirement. Prospective annual cost increases of up to 6% will be shared by CONSOL Energy and the participants based on their age and years of service at retirement. Annual cost increases in excess of 6% will be the responsibility of the participants. In addition, any salaried or non-represented hourly employees that were hired or rehired effective January 1, 2007 or later and do not work in a corporate or operational support position are not eligible for retiree health benefits. In lieu of traditional retiree health coverage, if certain eligibility requirements are met, these employees will receive a retiree medical spending allowance of $2,250 per year for each year of service at retirement. Newly employed inexperienced employees represented by the United Mine Workers of America (UMWA), hired after January 1, 2007, are not eligible to receive retiree benefits. In lieu of these benefits, these employees receive a defined contribution benefit of $1.00 per each hour worked through December 31, 2013, increasing to $1.50 per hour worked effective January 1, 2014 through December 31, 2016.

On March 31, 2012, the salaried OPEB plan was amended to 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 the contribution will be dependent on several factors, and 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 medical 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 described above upon meeting the eligibility requirements at retirement. 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 OPEB plan was remeasured on March 31, 2012 to reflect the reduction in benefits and the change in discount rate to 4.57% from 4.51% reflected at the December 31, 2011 measurement date. 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 resulted in a $9.4 million reduction in expense compared to what was originally expected to be recognized for the year ended December 31, 2012.

As of December 31, 2012, we conducted our annual review of the various actuarial assumptions, including discount rate, expected trend in health care costs, average remaining service period, average remaining life expectancy, per capita costs and participation level in each future year used by our independent actuary to estimate the cost and benefit obligations for our retiree health plans. Expected trends in future health care cost assumptions were adjusted from prior year to reflect recent experience and future expectations. The initial expected trend in health care costs at this year's measurement date was 6.30% with an ultimate trend rate of 4.50% expected to be reached in 2026. The initial expected trend rate at last year's measurement date was 6.85% with an ultimate trend rate of 4.50% expected to be reached in 2026. A 1.0% decrease in the health care trend rate would have decreased interest and service cost for 2012 by approximately $17.4 million. A 1.0% increase in the health care trend rate would have increased the interest and service cost by approximately $21.0 million. The discount rate is determined each year at the measurement date, or subsequent remeasurement date, if applicable. The discount rate is determined using a Company-specific yield curve model (above-mean) developed with assistance of an external actuary. The discount rate yield curve was updated to expand the high quality bond universe to address the significant decline in the number of bonds referenced in the establishment of the yield curve in the 10-30 year time period. The Company-specific yield curve model (above-mean) uses a subset of the expanded bond universe to determine the Company-specific discount rate. Bonds used in the yield curve are rated AA by Moody's or Standard & Poor's as of the measurement date. The yield curve model parallels the plans' projected cash flows, and the underlying cash flows of the bonds included in the model exceed the cash flows needed to satisfy the Company plans' obligations. At December 31, 2012 and March 31, 2012 (remeasurement date discussed above), the discount rate used to calculate the period end liability and the following year's expense was 4.05% and 4.57%, respectively. A 0.25% increase in the discount rate would have decreased 2012 net periodic postretirement benefit costs by approximately $4.5 million. A 0.25% decrease in the discount rate would have increased 2012 net periodic postretirement benefit costs by approximately $5.2 million. Deferred gains and losses are primarily due to historical changes in the discount rate and medical cost inflation differing from expectations in prior years. Changes to interest rates for the rates of returns on instruments that could be used to settle the actuarially determined plan obligations introduce substantial volatility to our costs. Accumulated actuarial gains or losses in excess of a pre-established corridor are amortized on a straight-line basis over the expected future service of active salary and non-represented employees to their assumed retirement age. At December 31, 2012, the average remaining service period is approximately 11 years for our non-represented plans. Accumulated actuarial gains or losses in excess of a pre-established corridor are amortized on a straight-line basis over the expected remaining life of our retired UMWA population. The average remaining service period of this population is not used for amortization purposes because the majority of the UMWA population of our plan is retired. At December 31, 2012, the average remaining life expectancy of our retired UMWA population used to calculate the following year's expense is approximately 12 years.

The weighted average per capita costs used to value the December 31, 2012 OPEB liability was approximately 7% less than previously expected based on our trend assumption. If the actual change in per capita cost of medical services or other postretirement benefits are significantly greater or less than the projected trend rates, the per capita cost assumption would need to be adjusted, which could have a significant effect on the costs and liabilities recorded in the financial statements.

Significant increases in health and prescription drug costs for represented hourly retirees could have a material adverse effect on CONSOL Energy's operating cash flow. However, the effect on CONSOL Energy's cash flow from operations for salaried employees is limited to approximately 6% of the previous year's medical cost for salaried employees due to the cost sharing provision in the benefit plan.

The estimated liability recognized in the December 31, 2012 financial statements was $3.0 billion. For the year ended December 31, 2012, we paid approximately $166.8 million for other postretirement benefits, all of which were paid from operating cash flow. Our obligations with respect to these liabilities are unfunded at December 31, 2012. CONSOL Energy does not expect to contribute to the other postretirement plan in 2013. We intend to pay benefit claims as they are due.

Salaried Pensions

CONSOL Energy has non-contributory defined benefit retirement plans covering substantially all employees not covered by multi-employer plans. The benefits for these plans are based primarily on years of service and employee's pay near retirement. CONSOL Energy's salaried plan allows for lump-sum distributions of benefits earned up until December 31, 2005, at the employees' election. The Restoration Plan was frozen effective December 31, 2006 and was replaced prospectively with the CONSOL Energy Supplemental Retirement Plan. CONSOL Energy's Restoration Plan allows only for lump-sum distributions earned up until December 31, 2006. Effective September 8, 2009, the Supplemental Retirement Plan was amended to include employees of CNX Gas. The Supplemental Retirement Plan was frozen effective December 31, 2011 for certain employees and was replaced prospectively with the CONSOL Energy Defined Contribution Restoration Plan.

Our independent actuaries calculate the actuarial present value of the estimated retirement obligation based on assumptions including rates of compensation, mortality rates, retirement age and interest rates. For the year ended December 31, 2012, compensation increases are assumed to range from 3% to 6% depending on age and job classification. The discount rate is determined each year at the measurement date, or subsequent remeasurement date, if applicable. The discount rate is determined using a Company-specific yield curve model (above-mean) developed with assistance of an external actuary. The discount rate yield curve was updated to expand the high quality bond universe to address the significant decline in the number of bonds referenced in the establishment of the yield curve in the 10-30 year time period. The Company-specific yield curve model (above-mean) uses a subset of the expanded bond universe to determine the Company-specific discount rate. Bonds used in the yield curve are rated AA by Moody's or Standard & Poor's as of the measurement date. The yield curve model parallels the plans' projected cash flows, and the underlying cash flows of the bonds included in the model exceed the cash flows needed to satisfy the Company plans'. For the years ended December 31, 2012 and 2011, the discount rate used to calculate the period end liability and the following year's expense was 4.00% and 4.50%, respectively. A 0.25% increase in the discount rate would have decreased the 2012 net periodic pension cost by $2.4 million. A 0.25% decrease in the discount rate would have increased the 2012 net periodic pension cost by $2.5 million. Deferred gains and losses are primarily due to historical changes in the discount rate and earnings on assets differing from expectations. At December 31, 2012 the average remaining service period is approximately 10 years. Changes to any of these assumptions introduce substantial volatility to our costs.

The assumed rate of return on plan assets also impacted CONSOL Energy's pension liability at December 31, 2012. Previously, the rate of return on plan assets was 8.00%. As of December 31, 2012 this assumption was lowered to 7.75%. A reduction of 0.25% would have increased 2012 expense by $1.4 million. The market related asset value is derived by taking the cost value of assets as of December 31, 2012 and multiplying it by the average 36-month ratio of the market value of assets to the cost value of assets. CONSOL Energy's pension plan weighted average asset allocations at December 31, 2012 consisted of 60% equity securities and 40% debt securities.

As a result of anticipated lump sum settlements in 2013 (including those associated with the 2012 VSIP), a pension settlement charge is reasonably possible to occur in 2013. When lump sum payments from the pension plan exceed the service and interest expense, pension settlement accounting requires unamortized actuarial gains and loss related to the lump sum payouts be amortized immediately. The 2013 threshold for pension settlement recognition is $55 million. If the threshold for pension settlement is reached, the pension settlement charge could be material to the financial results of CONSOL Energy. Also, pension settlement would require the pension plan to be remeasured using updated assumptions, which would include resetting the discount rate used in the actuarial calculation.

The estimated liability recognized in the December 31, 2012 financial statements was $224.9 million. For the year ended December 31, 2012, we contributed approximately $110.5 million to defined benefit retirement plans other than multi-employer plans and to other pension benefits. Our obligations with respect to these liabilities are partially funded at December 31, 2012. CONSOL Energy intends to contribute an amount that will avoid benefit restrictions for the following plan year.

Workers' Compensation and Coal Workers' Pneumoconiosis

Workers' compensation is a system by which individuals who sustain employment related physical injuries or some type of occupational diseases are compensated for their disabilities, medical costs, and on some occasions, for the costs of their rehabilitation. Workers' compensation will also compensate the survivors of workers who suffer employment related deaths. The workers' compensation laws are administered by state agencies with each state having its own set of rules and regulations regarding compensation that is owed to an employee that is injured in the course of employment. CONSOL Energy records an actuarially calculated liability, which is determined using various assumptions, including discount rate, future healthcare cost trends, benefit duration and recurrence of injuries. The discount rate is determined each year at the measurement date, or subsequent remeasurement date, if applicable. The discount rate is determined using a Company-specific yield curve model (above-mean) developed with assistance of an external actuary. The discount rate yield curve was updated to expand the high quality bond universe to address the significant decline in the number of bonds referenced in the establishment of the yield curve in the 10-30 year time period. The Company-specific yield curve model (above-mean) uses a subset of the expanded bond universe to determine the Company-specific discount rate. Bonds used in the yield curve are rated AA by Moody's or Standard & Poor's as of the measurement date. The yield curve model parallels the plans' projected cash flows, and the underlying cash flows of the bonds included in the model exceed the cash flows needed to satisfy the Company plans' obligations. For the years ended December 31, 2012 and 2011, the discount rate used to calculate the period end liability and the following year's expense was 3.95% and 4.40%, respectively. A 0.25% increase in the discount rate would have decreased the 2012 workers compensation expense cost by $0.4 million. A 0.25% decrease in the discount rate would have increased the 2012 workers compensation expense by $0.4 million. Deferred gains and losses are primarily due to historical changes in the discount rates, several years of favorable claims experience, various favorable state legislation changes and an overall lower incident rate than our assumptions. Accumulated actuarial gains or losses are amortized on a straight-line basis over the expected future service of active employees that are eligible to file a future workers' compensation claim. At December 31, 2012, the average remaining service period is approximately 9 years.

The estimated liability recognized in the financial statements at December 31, 2012 was approximately $179.6 million. CONSOL Energy's policy has been to provide for workers' compensation benefits from operating cash flow. For the year ended December 31, 2012, we made payments for workers' compensation benefits and other related fees of approximately $32.2 million, all of which was paid from operating cash flow. Our obligations with respect to these liabilities are unfunded at December 31, 2012.

CONSOL Energy is responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, for medical and disability benefits to employees and their dependents resulting from occurrences of coal workers' pneumoconiosis disease. CONSOL Energy is also responsible under various state statutes for pneumoconiosis benefits. After our review, our independent actuaries calculate the actuarial present value of the estimated pneumoconiosis obligation based on assumptions regarding disability incidence, medical costs, mortality, death benefits, dependents and discount rates. The discount rate is determined each year at the measurement date, or subsequent remeasurement date, if applicable. The discount rate is determined using a Company-specific yield curve model (above-mean) developed with assistance of an external actuary. The discount rate yield curve was updated to expand the high quality bond universe to address the significant decline in the number of bonds referenced in the establishment of the yield curve in the 10-30 year time period. The Company-specific yield curve model (above-mean) uses a subset of the expanded bond universe to determine the Company-specific discount rate. Bonds used in the yield curve are rated AA by Moody's or Standard & Poor's as of the measurement date. The yield curve model parallels the plans' projected cash flows, and the underlying cash flows of the bonds included in the model exceed the cash flows needed to satisfy the Company plans' obligations. For the years ended December 31, 2012 and 2011, the discount rate used to calculate the period end liability and the following year's expense was 4.03% and 4.46%, respectively. A 0.25% increase in the discount rate would have increased 2012 coal workers' pneumoconiosis benefit by $1.1 million. A 0.25% decrease in the discount rate would have decreased 2012 coal workers' pneumoconiosis benefit by $0.9 million. Actuarial gains associated with coal workers' pneumoconiosis have resulted from numerous legislative changes over many years which have resulted in lower approval rates for filed claims than our assumptions originally reflected. Actuarial gains have also resulted from lower incident rates and lower severity of claims filed than our assumptions originally reflected. Accumulated actuarial gains or losses are amortized on a straight-line basis over the expected future service of active employees. The estimated liability recognized in the financial statements at December 31, 2012 was $184.1 million. For the year ended December 31, 2012, we paid coal workers' pneumoconiosis benefits of approximately $11.3 million, all of which was paid from operating cash flow. Our obligations with respect to these liabilities are unfunded at December 31, 2012.

Reclamation, Mine Closure and Gas Well Closing Obligations

The Surface Mining Control and Reclamation Act established operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. CONSOL Energy accrues for the costs of current mine disturbance and final mine and gas well closure, including the cost of treating mine water discharge where necessary. Estimates of our total reclamation, mine-closing liabilities, and gas well closing which are based upon permit requirements and CONSOL Energy engineering expertise related to these requirements, including the current portion, were approximately $699.0 million at December 31, 2012. This liability is reviewed annually, or when events and circumstances indicate an adjustment is necessary, by CONSOL Energy management and engineers. The estimated liability can significantly change if actual costs vary from assumptions or if governmental regulations change significantly.

Accounting for Asset Retirement Obligations requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations primarily relate to the closure of mines and gas wells and the reclamation of land upon exhaustion of coal and gas reserves. Changes in the variables used to calculate the liabilities can have a significant effect on the mine closing, reclamation and gas well closing liabilities. The amounts of assets and liabilities recorded are dependent upon a number of variables, including the estimated future retirement costs, estimated proven reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rate.

Accounting for Asset Retirement Obligations also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. The depreciation will generally be determined on a units-of-production basis, whereas the accretion to be recognized will escalate over the life of the producing assets, typically as production declines.

Income Taxes

Deferred tax assets and liabilities are recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. All available evidence, both positive and negative, must be considered in determining the need for a valuation allowance. At December 31, 2012, CONSOL Energy has deferred tax assets in excess of deferred tax liabilities of approximately $592.7 million. The deferred tax assets are evaluated periodically to determine if a valuation allowance is necessary.

Deferred tax valuation allowances remained consistent for the years ended December 31, 2012 and 2011. CONSOL Energy continues to report deferred tax asset of approximately $35.8 million relating to its state net operating loss carry forwards subject to a full valuation allowance. A review of positive and negative evidence regarding these benefits, primarily the history of financial and tax losses on a separate company basis, concluded that a full valuation allowance was warranted. The net operating loss carry forwards expire at various times from 2018 to 2031. A valuation allowance of $5.3 million continues to be recognized against the state deferred tax asset attributable to future tax deductible differences for certain subsidiaries with histories of financial and tax losses. Management will continue to assess the realization of deferred tax assets attributable to state net operating loss carry forwards and future tax deductible differences based upon updated income forecast data and the feasibility of future tax planning strategies, and may record adjustments to valuation allowances against these deferred tax assets in future periods that could materially impact net income.

CONSOL Energy evaluates all tax positions taken on the state and federal tax filings to determine if the position is more likely than not to be sustained upon examination. For positions that meet the more likely than not to be sustained criteria, an evaluation to determine the largest amount of benefit, determined on a cumulative probability basis that is more likely than not to be realized upon ultimate settlement is determined. A previously recognized tax position is derecognized when it is subsequently determined that a tax position no longer meets the more likely than not threshold to be sustained. The evaluation of the sustainability of a tax position and the probable amount that is more likely than not is based on judgment, historical experience and on various other assumptions that we believe are reasonable under the circumstances. The results of these estimates, that are not readily apparent from other sources, form the basis for recognizing an uncertain tax liability. Actual results could differ from those estimates upon subsequent resolution of identified matters. Estimates of our uncertain tax liabilities, including interest and the current portion, were approximately $27.6 million at December 31, 2012.

Stock-Based Compensation

As of December 31, 2012, we have issued four types of share based payment awards: options, restricted stock units, performance stock options and performance share units. The Black-Scholes option pricing model is used to determine fair value of stock options at the grant date. Various inputs are utilized in the Black-Scholes pricing model, such as:

- stock price on measurement date,
- exercise price defined in the award,
- expected dividend yield based on historical trend of dividend payouts,
- risk-free interest rate based on a zero-coupon treasury bond rate,
- expected term based on historical grant and exercise behavior, and
- expected volatility based on historic and implied stock price volatility of CONSOL Energy stock and public peer group stock.

These factors can significantly impact the value of stock options expense recognized over the requisite service period of option holders.

The fair value of each restricted stock unit awarded is equivalent to the closing market price of a share of our company's stock on the date of the grant. The fair value of each performance share unit is determined by the underlying share price of our company stock on the date of the grant and management's estimate of the probability that the performance conditions required for vesting will be achieved.

As of December 31, 2012, $33.8 million of total unrecognized compensation cost related to unvested awards is expected to be recognized over a weighted-average period of 1.6 years. See Note 18-"Stock-based Compensation" in the Notes to the Audited Consolidated Financial Statements in Item 8 in this Form 10-K for more information.

Contingencies

CONSOL Energy is currently involved in certain legal proceedings. We have accrued our estimate of the probable costs for the resolution of these claims. This estimate has been developed in consultation with legal counsel involved in the defense of these matters and is based upon the nature of the lawsuit, progress of the case in court, view of legal counsel, prior experience in similar matters, and management's intended response. Future results of operations for any particular quarter or annual period could be materially affected by changes in our assumptions or the outcome of these proceedings. Legal fees associated with defending these various lawsuits and claims are expensed when incurred. See Note 23-Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 in this Form 10-K for further discussion.

Derivative Instruments

CONSOL Energy enters into financial derivative instruments to manage exposure to natural gas and oil price volatility. We measure every derivative instrument at fair value and record them on the balance sheet as either an asset or liability. Changes in fair value of 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 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 year. 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 fair values or cash flows of the hedge 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.

Coal and Gas Reserve Values

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal and gas reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal and gas reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Our coal reserves are periodically reviewed by an independent third party consultant. Our gas reserves are reviewed by independent experts each year. Some of the factors and assumptions which impact economically recoverable reserve estimates include:

- geological conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- assumptions governing future prices; and
- future operating costs.

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal and gas attributable to a particular group of properties, and classifications of these reserves based on risk of recovery and estimates of future net cash flows, may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and these variances may be material. See "Risk Factors" in Item 1A of this report for a discussion of the uncertainties in estimating our reserves.

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. 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 $1.5 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 adjusted earnings before interest, taxes, depreciation, depletion and amortization (Adjusted 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 Adjusted EBITDA to cash interest expense of CONSOL Energy and certain of its subsidiaries. The interest coverage ratio was 5.31 to 1.00 at December 31, 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 Adjusted 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, of CONSOL Energy and certain of its subsidiaries. Adjusted 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 2.50 to 1.00 at December 31, 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 Adjusted 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 December 31, 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 December 31, 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 December 31, 2012, eligible accounts receivable totaled approximately $200 million. At December 31, 2012, the facility had $38 million of outstanding borrowings and $162 million of letters of credit outstanding, leaving no 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 Adjusted EBITDA to cash interest expense for CNX Gas and its subsidiaries. The interest coverage ratio was 46.98 to 1.00 at December 31, 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 Adjusted EBITDA for CNX Gas and its

subsidiaries. Financial covenant debt is comprised of the outstanding indebtedness and letters of credit, less cash on hand, of CNX Gas and its subsidiaries. Adjusted 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 0.54 to 1.00 at December 31, 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 CONE are unrestricted. At December 31, 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, asset sales 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 $129 million at December 31, 2012. The ineffective portion of these contracts was insignificant to earnings in the year ended December 31, 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 Years Ended December 31,		
	2012	2011	Change
Cash flows from operating activities	$728	$1,528	$(800)
Cash used in investing activities	$(1,000)	$(579)	$(421)
Cash used in financing activities	$(82)	$(606)	$524

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

- Net income decreased $244 million in the period-to-period comparison; and
- The remaining $556 million decrease in operating cash flows was due to various other changes in operating assets, operating liabilities, other assets and other liabilities which occurred through both years, none of which were individually material.

Net cash used in investing activities increased $421 million in the period-to-period comparison primarily due to the following items:

- Capital expenditures increased $193 million due to:

- Coal segment increased capital expenditures $310 million in the period-to-period comparison. The increase was comprised of an additional $169 million in longwall shield projects, an additional $70 million for the Northern West Virginia RO system, an additional $37 million for an overland conveyor, an additional $30 million for the ongoing development of the BMX Mine (scheduled to begin production in early 2014) and an additional $34 million in various other individually insignificant projects, offset, in part, by a decrease of $30 million for a longwall face extension;

- Gas segment capital expenditures decreased $134 million due to management's decision to decrease CBM and conventional drilling during 2012 in response to low gas prices;
- Mineral lease expenditures associated with our advance mining royalties and leased coal assets increased $7 million in 2012; and

- Other capital expenditures increased $10 million related to various miscellaneous items, none of which were individually material.

- Proceeds from sale of assets decreased $101 million due to:

- Proceeds of an additional $158 million received in 2011 related to the Noble transaction;
- Proceeds of $190 million received in 2011 related to the sale of the Antero overriding royalty interest;
- Proceeds of $170 million received in 2012 related to the sale of non-producing Northern Powder River Basin (PRB) assets;
- Proceeds of $52 million received in 2012 from the Ram River & Scurry Canadian asset sale;
- Proceeds increased $25 million due to various other transactions that occurred throughout both periods, none of which were individually material.

- Distributions from/investments in equity affiliates decreased $79 million due to:

- Contributions of $42 million to CONE in order to meet the operating and capital expenditure;
- A cash distribution of $67 million from CONE Gathering LLC; and
- Net contributions of $30 million from various equity affiliates, none of which were individually significant.

- Restricted cash receipts of $48 million associated with the Ram River & Scurry Canadian asset sale.

Net cash used in financing activities increased $524 million in the period-to-period comparison primarily due to the following items:

- A make-whole provision of $266 million in 2011 to redeem 7.875% notes due in March 2012;
- Payments of $284 million in 2011 on short term borrowing under the revolving credit facility;
- Proceeds of $250 million in 2011 from the issuance of 6.375% senior unsecured notes due in March 2021;
- Payments of $200 million in 2011 under the accounts receivable securitization program;
- Proceeds of $25 million in 2012 from an interim funding agreement for the Bailey longwall shields;
- Proceeds of $38 million in 2012 from the accounts receivable securitization program;
- Increased dividend payments of $46 million in 2012 due to an additional dividend payment in 2012 associated with the acceleration of the fourth quarter dividend and the increase of the quarterly dividend for the entire year; and
- An increase of $7 million due to various transactions throughout both period, none of which were individually material.

116

The following is a summary of our significant contractual obligations at December 31, 2012 (in thousands):

	Payments due by Year				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Short-term Notes Payable	$25,073	$—	$—	$—	$25,073
Borrowings Under Securitization Facility	37,846	—	—	—	37,846
Purchase Order Firm Commitments	189,102	172,763	—	—	361,865
Gas Firm Transportation	80,359	148,502	130,919	435,384	795,164
Long-Term Debt	4,544	8,395	1,505,451	1,610,627	3,129,017
Interest on Long-Term Debt	244,977	490,664	430,800	369,842	1,536,283
Capital (Finance) Lease Obligations	8,941	14,464	10,932	24,717	59,054
Interest on Capital (Finance) Lease Obligations	3,895	6,118	4,455	3,692	18,160
Operating Lease Obligations	88,997	139,557	78,478	132,637	439,669
Long-Term Liabilities—Employee Related (a)	225,562	441,819	441,252	2,312,604	3,421,237
Other Long-Term Liabilities (b)	321,729	132,148	88,873	480,857	1,023,607
Total Contractual Obligations (c)	$1,231,025	$1,554,430	$2,691,160	$5,370,360	$10,846,975

(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 2013 contributions are expected to approximate $50 million to $75 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 December 31, 2012, CONSOL Energy had total long-term debt and capital lease obligations of $3.188 billion outstanding, including the current portion of long-term debt of $13 million. This long-term debt consisted of:

- An aggregate principal amount of $1.50 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% 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.
- Advance royalty commitments of $20 million with an average interest rate of 7.43% per annum.
- An aggregate principal amount of $6 million on other various rate notes maturing through June 2031.
- An aggregate principal amount of $59 million of capital leases with a weighted average interest rate of 6.38% per annum.

At December 31, 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 December 31, 2012, CONSOL Energy had $38 million in outstanding borrowings and had $162 million of letters of credit outstanding under the accounts receivable securitization facility.
At December 31, 2012, CONSOL Energy had $25 million in outstanding borrowings under an interim funding arrangement for longwall shields.

At December 31, 2012, CNX Gas, a wholly owned subsidiary, 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 $4.0 billion at December 31, 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 and changes in the fair value of cash flow hedges. See the Consolidated Statements of Stockholders' Equity in Item 8 of this Form 10-K for additional details.

Dividend information for the current year-to-date were as follows:

Declaration Date	Amount Per Share	Record Date	Payment Date
December 10, 2012	$0.125	December 21, 2012	December 28, 2012
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

On December 10, 2012, CONSOL Energy's board of directors accelerated the declaration and payment of the regular quarterly dividend of $0.125 per share, payable on December 28, 2012, to shareholders of record on December 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 $0.40 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 2.50 to 1.00 and our availability was approximately $1.4 billion at December 31, 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 $0.40 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 year ended December 31, 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 Audited Consolidated Financial Statements. CONSOL Energy participates in various multi-employer benefit plans such as the United Mine Workers’ of America (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 December 31, 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 this 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 December 31, 2012. Management believes these items will expire without being funded. See Note 23—Commitments and Contingencies in the Notes to the Audited Consolidated Financial Statements included in Item 8 of this Form 10-K 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.

ITEM 7A. 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 this Form 10-K.

A sensitivity analysis has been performed to determine the incremental effect on future earnings, related to open derivative instruments at December 31, 2012. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by $36.6 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by $36.6 million.

CONSOL Energy’s interest expense is sensitive to changes in the general level of interest rates in the United States. At December 31, 2012, CONSOL Energy had $3,189 million aggregate principal amount of debt outstanding under fixed-rate instruments and $63 million debt outstanding under variable-rate instruments. 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 December 31, 2012. CONSOL Energy’s revolving credit facility bore interest at a weighted average rate of 4.08% per annum during the year ended December 31, 2012. A 100 basis-point increase in the average rate for CONSOL Energy’s revolving credit facility would not have significantly decreased net income for the period. CNX Gas, also had borrowings during the period under its revolving credit facility which bears interest at a variable rate. CNX Gas’ facility had no outstanding borrowings at December 31, 2012 and bore interest at a weighted average rate of 2.08% per annum during the year ended December 31, 2012. Due to the level of borrowings against this facility and the low weighted average interest rate in the year ended December 31, 2012, a 100 basis-point increase in the average rate for CNX Gas’ revolving credit facility would not have significantly decreased net income for the period.

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.

Hedging Volumes

As of January 18, 2013 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
2013 Fixed Price Volumes					
Hedged Mcf	17,042,684	17,232,047	17,421,410	17,421,410	69,117,551
Weighted Average Hedge Price/Mcf	$4.66	$4.66	$4.66	$4.66	$4.66
2014 Fixed Price Volumes					
Hedged Mcf	14,487,673	14,648,647	14,809,621	14,809,621	58,755,562
Weighted Average Hedge Price/Mcf	$4.87	$4.87	$4.87	$4.87	$4.87
2015 Fixed Price Volumes					
Hedged Mcf	10,022,456	10,133,816	10,245,177	10,245,177	40,646,626
Weighted Average Hedge Price/Mcf	$4.10	$4.10	$4.10	$4.10	$4.10

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of CONSOL Energy Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of CONSOL Energy Inc. and Subsidiaries as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedule listed in the index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of CONSOL Energy Inc. and Subsidiaries at December 31, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), CONSOL Energy Inc. and Subsidiaries' internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 7, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Pittsburgh, Pennsylvania
February 7, 2013

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

	For the Years Ended December 31,		
	2012	2011	2010
Sales—Outside	$4,825,946	$5,660,813	$4,938,703
Sales—Gas Royalty Interests	49,405	66,929	62,869
Sales—Purchased Gas	3,316	4,344	11,227
Freight—Outside	141,936	231,536	125,715
Other Income (Note 3)	409,704	153,620	97,507
Total Revenue and Other Income	5,430,307	6,117,242	5,236,021
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	3,421,953	3,501,298	3,262,327
Gas Royalty Interests Costs	38,867	59,331	53,775
Purchased Gas Costs	2,711	3,831	9,736
Freight Expense	141,936	231,347	125,544
Selling, General and Administrative Expenses	148,071	175,467	150,210
Depreciation, Depletion and Amortization	622,780	618,397	567,663
Interest Expense (Note 4)	220,060	248,344	205,032
Taxes Other Than Income (Note 5)	336,655	344,460	328,458
Abandonment of Long-Lived Assets (Note 10)	—	115,817	—
Loss on Debt Extinguishment (Note 13)	—	16,090	—
Transaction and Financing Fees (Note 13)	—	14,907	65,363
Total Costs	4,933,033	5,329,289	4,768,108
Earnings Before Income Taxes	497,274	787,953	467,913
Income Taxes (Note 6)	109,201	155,456	109,287
Net Income	388,073	632,497	358,626
Less: Net Loss (Income) Attributable to Noncontrolling Interest	397	—	(11,845)
Net Income Attributable to CONSOL Energy Inc. Shareholders	$388,470	$632,497	$346,781
Earnings Per Share (Note 1):			
Basic	$1.71	$2.79	$1.61
Dilutive	$1.70	$2.76	$1.60
Weighted Average Number of Common Shares Outstanding (Note 1):			
Basic	227,593,524	226,680,369	214,920,561
Dilutive	229,141,767	229,003,599	217,037,804
Dividends Paid Per Share	$0.625	$0.425	$0.400

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

124

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

	For the Years Ended December 31,		
	2012	2011	2010
Net Income	$388,073	$632,497	$358,626
Other Comprehensive Income:			
Treasury Rate Lock (Net of tax: $-, $59, $49)	—	(96)	(84)
Actuarially Determined Long-Term Liability Adjustments (Net of tax: ($77,871), $1,583, $154,773)	129,231	(32,813)	(221,228)
Net Increase in the Value of Cash Flow Hedge (Net of tax: ($73,593), ($129,235), ($92,048))	114,240	200,700	140,985
Reclassification of Cash Flow Hedges from Other Comprehensive Income to Earnings (Net of tax: $121,484, $60,925, $108,031)	(189,259)	(95,007)	(166,276)
Purchase of CNX Gas Noncontrolling Interest	—	—	18,026
Other Comprehensive Income (Loss)	54,212	72,784	(228,577)
Comprehensive Income	442,285	705,281	130,049
Less: Comprehensive Loss (Income) Attributable to Noncontrolling Interest	397	—	(17,102)
Comprehensive Income Attributable to CONSOL Energy Inc. Shareholders	$442,682	$705,281	$112,947

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

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

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$21,878	$375,736
Accounts and Notes Receivable:		
Trade	428,328	462,812
Notes Receivable	318,387	314,950
Other Receivables	131,131	105,708
Accounts Receivable—Securitized (Note 9)	37,846	—
Inventories (Note 8)	247,766	258,335
Deferred Income Taxes (Note 6)	148,104	141,083
Restricted Cash (Note 1)	48,294	—
Prepaid Expenses	157,360	239,353
Total Current Assets	1,539,094	1,897,977
Property, Plant and Equipment (Note 10):		
Property, Plant and Equipment	15,545,204	14,087,319
Less—Accumulated Depreciation, Depletion and Amortization	5,354,237	4,760,903
Total Property, Plant and Equipment—Net	10,190,967	9,326,416
Other Assets:		
Deferred Income Taxes (Note 6)	444,585	507,724
Restricted Cash (Note 1)	20,379	22,148
Investment in Affiliates	222,830	182,036
Notes Receivable	25,977	300,492
Other	227,077	288,907
Total Other Assets	940,848	1,301,307
TOTAL ASSETS	$12,670,909	$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)

	December 31, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts Payable	$507,982	$522,003
Current Portion of Long-Term Debt (Note 13 and Note 14)	13,485	20,691
Short-Term Notes Payable (Note 11)	25,073	—
Accrued Income Taxes	34,219	75,633
Borrowings Under Securitization Facility (Note 9)	37,846	—
Other Accrued Liabilities (Note 12)	768,494	770,070
Total Current Liabilities	1,387,099	1,388,397
Long-Term Debt:		
Long-Term Debt (Note 13)	3,124,473	3,122,234
Capital Lease Obligations (Note 14)	50,113	55,189
Total Long-Term Debt	3,174,586	3,177,423
Deferred Credits and Other Liabilities:		
Postretirement Benefits Other Than Pensions (Note 15)	2,832,401	3,059,671
Pneumoconiosis Benefits (Note 16)	174,781	173,553
Mine Closing (Note 7)	446,727	406,712
Gas Well Closing (Note 7)	148,928	124,051
Workers' Compensation (Note 16)	155,648	151,034
Salary Retirement (Note 15)	218,004	269,069
Reclamation (Note 7)	47,965	39,969
Other	131,025	124,936
Total Deferred Credits and Other Liabilities	4,155,479	4,348,995
TOTAL LIABILITIES	8,717,164	8,914,815
Stockholders' Equity:		
Common Stock, $.01 Par Value; 500,000,000 Shares Authorized, 228,129,467 Issued and 228,094,712 Outstanding at December 31, 2012; 227,289,426 Issued and 227,056,212 Outstanding at December 31, 2011	2,284	2,273
Capital in Excess of Par Value	2,296,908	2,234,775
Preferred Stock, 15,000,000 Shares Authorized, None Issued and Outstanding	—	—
Retained Earnings	2,402,551	2,184,737
Accumulated Other Comprehensive Loss	(747,342)	(801,554)
Common Stock in Treasury, at Cost—34,755 Shares at December 31, 2012 and 233,214 Shares at December 31, 2011	(609)	(9,346)
Total CONSOL Energy Inc. Stockholders' Equity	3,953,792	3,610,885
Noncontrolling Interest	(47)	—
TOTAL EQUITY	3,953,745	3,610,885
TOTAL LIABILITIES AND EQUITY	$12,670,909	$12,525,700

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

127

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, 2009	$1,830	$1,033,616	$1,456,898	$(640,504)	$(66,292)	$1,785,548	$238,931	$2,024,479
Net Income	—	—	346,781	—	—	346,781	11,845	358,626
Treasury Rate Lock (Net of $49 Tax)	—	—	—	(84)	—	(84)	—	(84)
Gas Cash Flow Hedge (Net of $15,983 Tax)	—	—	—	(30,543)	—	(30,543)	5,252	(25,291)
Actuarially Determined Long-Term Liability Adjustments (Net of $154,773 Tax)	—	—	—	(221,233)	—	(221,233)	5	(221,228)
Purchase of CNX Gas Noncontrolling Interest	—	—	—	18,026	—	18,026	—	18,026
Comprehensive Income (Loss)	—	—	346,781	(233,834)	—	112,947	17,102	130,049
Issuance of Treasury Stock	—	—	(37,221)	—	23,633	(13,588)	—	(13,588)
Issuance of Common Stock	443	1,828,419	—	—	—	1,828,862	—	1,828,862
Issuance of CNX Gas Stock	—	—	—	—	—	—	2,178	2,178
Purchase of CNX Gas Noncontrolling Interest	—	(746,052)	—	—	—	(746,052)	(263,008)	(1,009,060)
Tax Benefit from Stock-Based Compensation	—	15,100	—	—	—	15,100	—	15,100
Amortization of Stock-Based Compensation Awards	—	45,395	—	—	—	45,395	2,198	47,593
	—	2,126	—	—	—	2,126	(1,771)	355

Stock-Based Compensation Awards to CNX Gas Employees								
Net Change in Noncontrolling Interest	—	—	—	—	—	—	(4,094)	(4,094)
Dividends ($0.40 per share)	—	—	(85,861)	—	—	(85,861)	—	(85,861)
Balance at December 31, 2010	2,273	2,178,604	1,680,597	(874,338)	(42,659)	2,944,477	(8,464)	2,936,013
Net Income	—	—	632,497	—	—	632,497	—	632,497
Treasury Rate Lock (Net of $59 Tax)	—	—	—	(96)	—	(96)	—	(96)
Gas Cash Flow Hedge (Net of ($68,310) Tax)	—	—	—	105,693	—	105,693	—	105,693
Actuarially Determined Long-Term Liability Adjustments (Net of $1,583 Tax)	—	—	—	(32,813)	—	(32,813)	—	(32,813)
Comprehensive Income (Loss)	—	—	632,497	72,784	—	705,281	—	705,281
Issuance of Treasury Stock	—	—	(32,001)	—	33,313	1,312	—	1,312
Tax Benefit from Stock-Based Compensation	—	7,329	—	—	—	7,329	—	7,329
Amortization of Stock-Based Compensation Awards	—	48,842	—	—	—	48,842	—	48,842
Net Change in Noncontrolling Interest	—	—	—	—	—	—	8,464	8,464
Dividends ($0.425 per share)	—	—	(96,356)	—	—	(96,356)	—	(96,356)
Balance at December 31, 2011	2,273	2,234,775	2,184,737	(801,554)	(9,346)	3,610,885	—	3,610,885
Net Income	—	—	388,470	—	—	388,470	(397)	388,073
Gas Cash Flow Hedge (Net of $47,891 Tax)	—	—	—	(75,019)	—	(75,019)	—	(75,019)
Actuarially Determined Long-Term	—	—	—	129,231	—	129,231	—	129,231

Liability Adjustments (Net of ($77,871) Tax)								
Comprehensive Income (Loss)	—	—	388,470	54,212	—	442,682	(397)	442,285
Issuance of Treasury Stock	—	—	(28,378)	—	8,737	(19,641)	—	(19,641)
Issuance of Common Stock	11	8,267	—	—	—	8,278	—	8,278
Tax Benefit from Stock-Based Compensation	—	6,028	—	—	—	6,028	—	6,028
Amortization of Stock-Based Compensation Awards	—	47,838	—	—	—	47,838	—	47,838
Net Change in Noncontrolling Interest	—	—	—	—	—	—	350	350
Dividends ($0.625 per share)	—	—	(142,278)	—	—	(142,278)	—	(142,278)
Balance at December 31, 2012	$2,284	$2,296,908	$2,402,551	$(747,342)	$(609)	$3,953,792	$(47)	$3,953,745

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

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

	For the Years Ended December 31,		
	2012	2011	2010
Cash Flows from Operating Activities:			
Net Income	$388,073	$632,497	$358,626
Adjustments to Reconcile Net Income to Net Cash Provided By Operating Activities:			
Depreciation, Depletion and Amortization	622,780	618,397	567,663
Abandonment of Long-Lived Assets	—	115,817	—
Stock-Based Compensation	47,838	48,842	47,593
Gain on Sale of Assets	(282,235)	(46,497)	(9,908)
Loss on Debt Extinguishment	—	16,090	—
Amortization of Mineral Leases	4,658	7,608	4,160
Deferred Income Taxes	(6,649)	(53,011)	17,029
Equity in Earnings of Affiliates	(27,048)	(24,663)	(21,428)
Changes in Operating Assets:			
Accounts and Notes Receivable	(20,218)	(83,770)	(96,245)
Inventories	10,569	(380)	48,919
Prepaid Expenses	8,095	4,431	(20,974)
Changes in Other Assets	(7,041)	17,745	7,237
Changes in Operating Liabilities:			
Accounts Payable	(20,106)	144,652	78,839
Other Operating Liabilities	(12,634)	84,146	129,230
Changes in Other Liabilities	1,917	30,309	(15,443)
Other	20,130	15,393	36,014
Net Cash Provided by Operating Activities	728,129	1,527,606	1,131,312
Cash Flows from Investing Activities:			
Capital Expenditures	(1,575,230)	(1,382,371)	(1,154,024)
Acquisition of Dominion Exploration and Production Business	—	—	(3,470,212)
Purchase of CNX Gas Noncontrolling Interest	—	—	(991,034)
Change in Restricted Cash	(48,294)	—	—
Proceeds from Sales of Assets	646,565	747,971	59,844
Distributions From, net of (Investments In), Equity Affiliates	(23,451)	55,876	11,452
Net Cash Used in Investing Activities	(1,000,410)	(578,524)	(5,543,974)
Cash Flows from Financing Activities:			
Payments on Short-Term Borrowings	—	(284,000)	(188,850)
Proceeds from (Payments on) Miscellaneous Borrowings	15,594	(11,627)	(11,412)
Proceeds from (Payments on) Securitization Facility	37,846	(200,000)	150,000
Payments on Long-Term Notes, Including Redemption Premium	—	(265,785)	—
Proceeds from Issuance of Long-Term Notes	—	250,000	2,750,000
Tax Benefit from Stock-Based Compensation	8,678	8,281	15,365
Dividends Paid	(142,278)	(96,356)	(85,861)
Proceeds from Issuance of Common Stock	8,278	—	1,828,862
(Purchases) Issuance of Treasury Stock	(9,485)	9,033	5,993
Debt Issuance and Financing Fees	(210)	(15,686)	(84,248)
Net Cash (Used In) Provided By Financing Activities	(81,577)	(606,140)	4,379,849
Net (Decrease) Increase in Cash and Cash Equivalents	(353,858)	342,942	(32,813)

Cash and Cash Equivalents at Beginning of Period	375,736	32,794	65,607
Cash and Cash Equivalents at End of Period	$21,878	$375,736	$32,794

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

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

NOTE 1—SIGNIFICANT ACCOUNTING POLICIES:
A summary of the significant accounting policies of CONSOL Energy Inc. and subsidiaries (CONSOL Energy or the Company) is presented below. These, together with the other notes that follow, are an integral part of the Consolidated Financial Statements.
Basis of Consolidation:
The Consolidated Financial Statements include the accounts of majority-owned and controlled subsidiaries. Investments in business entities in which CONSOL Energy does not have control, but has the ability to exercise significant influence over the operating and financial policies, are accounted for under the equity method. Investments in oil and gas producing entities are accounted for under the proportionate consolidation method. The accounts of variable interest entities, where CONSOL Energy is the primary beneficiary, are included in the Consolidated Financial Statements. All significant intercompany transactions and accounts have been eliminated in consolidation.
Use of Estimates:
The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and various disclosures. Actual results could differ from those estimates. The most significant estimates included in the preparation of the financial statements are related to business combinations, other postretirement benefits, coal workers' pneumoconiosis, workers' compensation, salary retirement benefits, stock-based compensation, asset retirement obligations, deferred income tax assets and liabilities, contingencies, and coal and gas reserve values.
Cash and Cash Equivalents:
Cash and cash equivalents include cash on hand and on deposit at banking institutions as well as all highly liquid short-term securities with original maturities of three months or less.
Trade Accounts Receivable:
Trade accounts receivable are recorded at the invoiced amount and do not bear interest. CONSOL Energy reserves for specific accounts receivable when it is probable that all or a part of an outstanding balance will not be collected, such as customer bankruptcies. Collectability is determined based on terms of sale, credit status of customers and various other circumstances. CONSOL Energy regularly reviews collectability and establishes or adjusts the allowance as necessary using the specific identification method. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. Reserves for uncollectible amounts were not material in the periods presented. There were no material financing receivables with a contractual maturity greater than one year.
Inventories:
Inventories are stated at the lower of cost or market. The cost of coal inventories is determined by the first-in, first-out (FIFO) method. Coal inventory costs include labor, supplies, equipment costs, operating overhead and other related costs. The cost of merchandise for resale is determined by the last-in, first-out (LIFO) method and includes industrial maintenance, repair and operating supplies for sale to third parties. The cost of supplies inventory is determined by the average cost method and includes operating and maintenance supplies to be used in our coal and gas operations.
Property, Plant and Equipment:
Property, plant and equipment is recorded at cost upon acquisition. Expenditures which extend the useful lives of existing plant and equipment are capitalized. Interest costs applicable to major asset additions are capitalized during the construction period. Costs of additional mine facilities required to maintain production after a mine reaches the production stage, generally referred to as “receding face costs,” are expensed as incurred; however, the costs of additional airshafts and new portals are capitalized. Planned major maintenance costs which do not extend the useful lives of existing plant and equipment are expensed as incurred.

Coal exploration costs are expensed as incurred. Coal exploration costs include those incurred to ascertain existence, location, extent or quality of ore or minerals before beginning the development stage of the mine.

Costs of developing new underground mines and certain underground expansion projects are capitalized. Underground development costs, which are costs incurred to make the mineral physically accessible, include costs to prepare property for shafts, driving main entries for ventilation, haulage, personnel, construction of airshafts, roof protection and other facilities. Costs of developing the first pit within a permitted area of a surface mine are capitalized. A surface mine is defined as the permitted mining area which includes various adjacent pits that share common infrastructure, processing equipment and a common ore body. Surface mine development costs include construction costs for entry roads, drilling, blasting and removal of overburden in developing the first cut for mountain stripping or box cuts for surface stripping. Stripping costs incurred during the production phase of a mine are expensed as incurred.

Airshafts and capitalized mine development associated with a coal reserve are amortized on a units-of-production basis as the coal is produced so that each ton of coal is assigned a portion of the unamortized costs. We employ this method to match costs with the related revenues realized in a particular period. Rates are updated when revisions to coal reserve estimates are made. Coal reserve estimates are reviewed when information becomes available that indicates a reserve change is needed, or at a minimum once a year. Any material effect from changes in estimates is disclosed in the period the change occurs. Amortization of development cost begins when the development phase is complete and the production phase begins. At an underground mine, the end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Coal extracted during the development phase is incidental to the mine's production capacity and is not considered to shift the mine into the production phase.

Advance mining royalties are advance payments made to lessors under terms of mineral lease agreements that are recoupable against future production using the units-of-production method. Depletion of leased coal interests is computed using the units-of-production method over proven and probable coal reserves. Advance mining royalties and leased coal interests are evaluated periodically, or at a minimum once a year, for impairment issues or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Any revisions are accounted for prospectively as changes in accounting estimates.

When properties are retired or otherwise disposed, the related cost and accumulated depreciation are removed from the respective accounts and any profit or loss on disposition is recognized as gain or loss in other income.

Gas well activity is accounted for under the successful efforts method of accounting. Costs of property acquisitions, successful exploratory, development wells and related support equipment and facilities are capitalized. Periodic valuation provisions for impairment of capitalized costs of unproved mineral interests are expensed. Costs of unsuccessful exploratory wells are expensed when such wells are determined to be non-productive, or if the determination cannot be made after finding sufficient quantities of reserves to continue evaluating the viability of the project. The costs of producing properties and mineral interests are amortized using the units-of-production method. Wells and related equipment and intangible drilling costs are amortized on a units-of-production method. Units-of-production amortization rates are revised when events and circumstances indicate an adjustment is necessary, or at a minimum once a year; those revisions are accounted for prospectively as changes in accounting estimates.

Depreciation of plant and equipment is calculated on the straight-line method over their estimated useful lives or lease terms generally as follows:

	Years
Buildings and improvements	10 to 45
Machinery and equipment	3 to 25
Leasehold improvements	Life of Lease

Costs to obtain coal lands are capitalized based on the cost at acquisition and are amortized using the units-of-production method over all estimated proven and probable reserve tons assigned and accessible to the mine. Proven and probable coal reserves exclude non-recoverable coal reserves and anticipated processing losses. Rates are updated when revisions to coal reserve estimates are made. Coal reserve estimates are reviewed when events and circumstances indicate a reserve change is needed, or at a minimum once a year. Amortization of coal interests begins when the coal reserve is produced. At an underground mine, a ton is considered produced once it reaches the surface area of the mine. Any material effect from changes in estimates is disclosed in the period the change occurs.

Costs for purchased and internally developed software are expensed until it has been determined that the software will result in probable future economic benefits and management has committed to funding the project. Thereafter, all direct costs of materials and services incurred in developing or obtaining software, including certain payroll and benefit costs of employees associated with the project, are capitalized and amortized using the straight-line method over the estimated useful life which does not exceed seven years.

Impairment of Long-lived Assets:
Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the assets is then reduced to its estimated fair value which is usually measured based on an estimate of future discounted cash flows. Impairment of equity investments is recorded when indicators of impairment are present and the estimated fair value of the investment is less than the assets' carrying value. There was no impairment expense recognized for the years ended December 31, 2012, 2011, and 2010.
Income Taxes:
Deferred tax assets and liabilities are recognized for the expected future tax consequences of events that have been recognized in CONSOL Energy's financial statements or tax returns. The provision for income taxes represents income taxes paid or payable for the current year and the change in deferred taxes, excluding the effects of acquisitions during the year. Deferred taxes result from differences between the financial and tax bases of CONSOL Energy's assets and liabilities and are adjusted for changes in tax rates and tax laws when changes are enacted. Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that a deferred tax benefit will not be realized.
CONSOL Energy evaluates all tax positions taken on the state and federal tax filings to determine if the position is more likely than not to be sustained upon examination. For positions that do not meet the more likely than not to be sustained criteria, an evaluation to determine the largest amount of benefit, determined on a cumulative probability basis that is more likely than not to be realized upon ultimate settlement, is determined. A previously recognized tax position is derecognized when it is subsequently determined that a tax position no longer meets the more likely than not threshold to be sustained. The evaluation of the sustainability of a tax position and the probable amount that is more likely than not is based on judgment, historical experience and on various other assumptions that we believe are reasonable under the circumstances. The results of these estimates, that are not readily apparent from other sources, form the basis for recognizing an uncertain tax position liability. Actual results could differ from those estimates upon subsequent resolution of identified matters.
Restricted Cash:
Restricted cash includes a $48,294 deposit into escrow associated with the Ram River Asset sale. The deposit will be released upon CONSOL Energy's filing of all Canadian tax returns associated with the transaction. Restricted cash also includes a $20,379 deposit into escrow as security to perfect CONSOL Energy's appeal to the Pennsylvania Environmental Hearing Board under the applicable statute related to the Ryerson dam litigation (See Note 23–Commitments and Contingent Liabilities for additional details.)
Postretirement Benefits Other Than Pensions:
Postretirement benefits other than pensions, except for those established pursuant to the Coal Industry Retiree Health Benefit Act of 1992 (the Health Benefit Act), are accounted for in accordance with the Retirement Benefits Compensation and Non-retirement Postemployment Benefits Compensation Topics of the FASB Accounting Standards Codification which requires employers to accrue the cost of such retirement benefits for the employees' active service periods. Such liabilities are determined on an actuarial basis and CONSOL Energy is primarily self-insured for these benefits. Postretirement benefit obligations established by the Health Benefit Act are treated as a multi-employer plan which requires expense to be recorded for the associated obligations as payments are made.
Pneumoconiosis Benefits and Workers' Compensation:
CONSOL Energy is required by federal and state statutes to provide benefits to certain current and former totally disabled employees or their dependents for awards related to coal workers' pneumoconiosis. CONSOL Energy is also required by various state statutes to provide workers' compensation benefits for employees who sustain employment related physical injuries or some types of occupational disease. Workers' compensation benefits include compensation for their disability, medical costs, and on some occasions, the cost of rehabilitation. CONSOL Energy is primarily self-insured for these benefits. Provisions for estimated benefits are determined on an actuarial basis.

Mine Closing, Reclamation and Gas Well Closing Costs:

CONSOL Energy accrues for mine closing costs, reclamation costs, perpetual water care costs and dismantling and removing costs of gas related facilities using the accounting treatment prescribed by the Asset Retirement and Environmental Obligations Topic of the FASB Accounting Standards Codification. This topic requires the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. Depreciation of the capitalized asset retirement cost is generally determined on a units-of-production basis. Accretion of the asset retirement obligation is recognized over time and generally will escalate over the life of the producing asset, typically as production declines. Accretion is included in Cost of Goods Sold and Other Operating Charges on the Consolidated Statements of Income. Asset retirement obligations primarily relate to the closure of mines and gas wells, which includes treatment of water and the reclamation of land upon exhaustion of coal and gas reserves.

Accrued mine closing costs, perpetual care costs, reclamation and costs of dismantling and removing gas related facilities are regularly reviewed by management and are revised for changes in future estimated costs and regulatory requirements.

Retirement Plans:

CONSOL Energy has non-contributory defined benefit retirement plans covering substantially all employees not covered by multi-employer retirement plans. These plans are accounted for using the guidance outlined in the Compensation - Retirement Benefits Topic of the FASB Accounting Standards Codification. The cost of these retiree benefits are recognized over the employees' service period. CONSOL Energy uses actuarial methods and assumptions in the valuation of defined benefit obligations and the determination of expense. Differences between actual and expected results or changes in the value of obligations and plan assets are recognized through Other Comprehensive Income.

Revenue Recognition:

Revenues are recognized when title passes to the customers. For domestic coal sales, this generally occurs when coal is loaded at mine or offsite storage locations. For export coal sales, this generally occurs when coal is loaded onto marine vessels at terminal locations. For gas sales, this occurs at the contractual point of delivery. For industrial supplies and equipment sales, this generally occurs when the products are delivered. For terminal, river and dock, land and research and development, revenue is recognized generally as the service is provided to the customer.

CONSOL Energy has operational gas-balancing agreements with various interstate pipelines. These imbalance agreements are managed internally using the sales method of accounting. The sales method recognizes revenue when the gas is taken by the purchaser.

CONSOL Energy sells gas to accommodate the delivery points of its customers. In general this gas is purchased at market price and re-sold on the same day at market price less a small transaction fee. These matching buy/sell transactions include a legal right of offset of obligations and have been simultaneously entered into with the counterparty which qualify for netting under the Nonmonetary Transactions Topic of the FASB Accounting Standards Codification and are therefore reflected net on the income statement in Cost of Goods Sold and Other Operating Charges.

CONSOL Energy purchases gas produced by third parties at market prices less a fee. The gas purchased from third party producers is then resold to end users or gas marketers at current market prices. These revenues and expenses are recorded gross as Purchased Gas Revenue and Purchased Gas Costs in the Consolidated Statements of Income. Purchased gas revenue is recognized when title passes to the customer. Purchased gas costs are recognized when title passes to CONSOL Energy from the third party producer.

Royalty Interest Gas Sales represent the revenues related to the portion of production belonging to royalty interest owners sold by CONSOL Energy.

Freight Revenue and Expense:

Shipping and handling costs invoiced to coal customers and paid to third-party carriers are recorded as Freight Revenue and Freight Expense, respectively.

Royalty Recognition:

Royalty expenses for coal rights are included in Cost of Goods Sold and Other Operating Charges when the related revenue for the coal sale is recognized. Royalty expenses for gas rights are included in Gas Royalty Interest Costs when the related revenue for the gas sale is recognized. These royalty expenses are paid in cash in accordance with the terms of each agreement. Revenues for coal and gas sold related to production under royalty contracts, versus owned by CONSOL Energy, are recorded on a gross basis.

Contingencies:

CONSOL Energy, or our subsidiaries, from time to time is 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. Liabilities are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Estimates are developed through consultation with legal counsel involved in the defense of these matters and are based upon the nature of the lawsuit, progress of the case in court, view of legal counsel, prior experience in similar matters and managements intended response. Environmental liabilities are not discounted or reduced by possible recoveries from third parties. Legal fees associated with defending these various lawsuits and claims are expensed when incurred.

Issuance of Common Stock:

On March 31, 2010, CONSOL Energy issued 44,275,000 shares of common stock, which generated net proceeds of $1,828,862 to fund, in part, the acquisition of the Appalachian oil and gas exploration and production business of Dominion Resources, Inc. (Dominion Acquisition). The acquisition transaction closed on April 30, 2010. See Note 2–Acquisitions and Dispositions for further discussion of the Dominion Acquisition.

Stock-Based Compensation:

Stock-based compensation expense for all stock-based compensation awards is based on the grant date fair value estimated in accordance with the provisions of Stock Compensation Topic of the FASB Accounting Standards Codification. CONSOL Energy recognizes these compensation costs on a straight-line basis over the requisite service period of the award, which is generally the award's vesting term. See Note 18–Stock Based Compensation for further discussion.

Earnings per Share:

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 stock 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 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 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:

	For the Years Ended December 31,		
	2012	2011	2010
Anti-Dilutive Options	2,411,963	1,156,018	813,833
Anti-Dilutive Restricted Stock Units	8,822	—	1,960
Anti-Dilutive Performance Share Units	445,847	—	—
Anti-Dilutive Performance Share Options	501,744	—	—
	3,368,376	1,156,018	815,793

	For the Years Ended December 31,		
	2012	2011	2010
Net income attributable to CONSOL Energy Inc. shareholders	$388,470	$632,497	$346,781
Weighted average shares of common stock outstanding:			
Basic	227,593,524	226,680,369	214,920,561
Effect of stock-based compensation awards	1,548,243	2,323,230	2,117,243
Dilutive	229,141,767	229,003,599	217,037,804
Earnings per share:			
Basic	$1.71	$2.79	$1.61
Dilutive	$1.70	$2.76	$1.60

Shares of common stock outstanding were as follows:

	2012	2011	2010
Balance, beginning of year	227,056,212	226,162,133	181,086,267
Issuance related to Stock-Based Compensation(1)	1,038,500	894,079	800,866
Issuance of Common Stock(2)	—	—	44,275,000
Balance, end of year	228,094,712	227,056,212	226,162,133

(1) See Note 18–Stock-Based Compensation for additional information.
(2) See Issuance of Common Stock in Note 1 for additional information.

Accounting for Derivative Instruments:

CONSOL Energy accounts for derivative instruments in accordance with the Derivatives and Hedging Topic of the FASB Accounting Standards Codification. This requires CONSOL Energy to measure every derivative instrument (including certain derivative instruments embedded in other contracts) at fair value and record them in the balance sheet as either an asset or liability. Changes in fair value of derivatives are recorded currently in earnings unless special hedge accounting criteria are met. For derivatives designated as cash flow hedges, the effective portions of changes in fair value of the derivative are reported in other comprehensive income. The ineffective portions of hedges are recognized in earnings in the current period.

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 fair values or 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.

Accounting for Business Combinations:

CONSOL Energy accounts for its business acquisitions under the acquisition method of accounting consistent with the requirements of the Business Combination Topic of the FASB Accounting Standards Codification. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions with respect to future cash inflows and outflows, discount rates and asset lives, among other items.

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.

Reclassifications:

Certain amounts in prior periods have been reclassified to conform with the report classifications of the year ended December 31, 2012, with no effect on previously reported net income or stockholders' equity.

Subsequent Events:

We have evaluated all subsequent events through the date the financial statements were issued. No material recognized or non-recognizable subsequent events were identified.

NOTE 2—ACQUISITIONS AND DISPOSITIONS:

On December 21, 2012, CONSOL Energy completed the disposition of its non-producing Ram River & Scurry Ram assets in Western Canada which consisted of 36 thousand acres of coal lands. In December 2012, cash proceeds of $51,869, of which $48,294 was restricted, were received related to this transaction, which were net of $637 in transaction fees. Additionally, a note receivable was recognized related to the two additional cash payments to be received in June 2013 and June 2014. Notes receivables of $25,500 and $24,500 were recorded in Accounts and Notes Receivables—Notes Receivable and Other Assets—Notes Receivable, respectively. The gain on the transaction was $89,943 and is included in Other Income in the Consolidated Statement of Income for the year ended December 31, 2012.

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 Statement of Income for the year ended December 31, 2012. 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 Statement of Income for the year ended December 31, 2012.

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 Statement of Income for the year ended December 31, 2012.

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 nearly 200 thousand net Utica Shale acres in Ohio. Cash proceeds related to this transaction were $54,254, which were 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 Consolidated Statements of Income as Other Income for the year 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. During December 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. Adjusted cash proceeds of $15,598 related to the additional receivable were received in April 2012. The net loss on the transaction was $64,142 and was recognized in the Consolidated Statements of Income as Other Income for the year ended December 31, 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 our joint venture agreements with Noble Energy and Hess, each of them has the right to perform due diligence on the title to the oil and gas interests which we conveyed to them and to assert that title to the acreage is defective. CONSOL Energy then can review and respond to the asserted title defects, or cure them, and ultimately, if the claim is not resolved, either party can submit the defect to an arbitrator for resolution. CONSOL Energy also has the right to require the defected acreage to be reassigned in certain circumstances. We are currently engaged in this title review process with Noble and Hess. If they establish any title defects which are not resolved in favor of CONSOL Energy or if the subject acreage is reassigned to us at our request, then subject to certain deductibles, Noble's and Hess's respective aggregate carried cost obligation under the joint venture agreements will be reduced by the value the parties previously allocated to the affected acreage in the transaction. 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. To date, Noble has asserted formal title defects with respect to approximately 30,171 gross deal acres, which have an aggregate transaction value of $175,000 . We believe that we will resolve most of those defects favorably to CONSOL Energy. To date, we have conceded defects to Noble which have an aggregate value equal to less than the applicable deductibles and the impact of these conceded defects on the Company's financial statements has not been material. In the case of our Ohio Utica Shale joint venture with Hess, based on title work performed by Hess, we believe that there are chain of title issues with respect to approximately 36,000 of the joint venture acres, most of which likely cannot be cured. Hess's 50% interest in these 36,000 acres has an allocated transaction value of approximately $146,000. If these chain of title issues are not cured, the carry value related to the transaction will be reduced by the applicable allocated transaction value. The loss of these Utica Shale acres itself will not have a material impact on the Company's financial statements. After accounting for these defective acres, there are approximately 161,000 acres in our Ohio Utica Shale joint venture with Hess.

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 periods presented below are prepared as if the transaction occurred as of January 1, 2010 and do not include material, non-recurring charges.

	Year Ended December 31,	
	2011	2010
Total Revenue and Other Income	$6,073,904	$5,212,597
Earnings Before Income Taxes	$775,807	$465,740
Net Income Attributable to CONSOL Energy Inc. Shareholders	$623,114	$345,169
Basic Earnings Per Share	$2.75	$1.60

Dilutive Earnings Per Share	$2.72	$1.59

The pro forma results are not necessarily indicative of what actually would have occurred if the transaction had been completed as of January 1, 2010, 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 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 in the amount of $67,545. The cash proceeds have been recorded as cash inflows of $59,870 and $7,675 in Distributions from Equity Affiliates and Proceeds from the Sale of Assets, respectively, on the Consolidated

Statements of Cash Flow. The gain on the transaction was $7,161 and was recognized in the Consolidated Statements of Income as Other Income for the year ended December 31, 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 Consolidated Statements of Income as Other Income for the year ended December 31, 2011.

In December 2010, CONSOL Energy completed a sale-leaseback of longwall shields for the McElroy Mine. Cash proceeds from the sale were $33,383, which was the same as our basis in the equipment. Accordingly, no gain or loss was recognized on the transaction. The lease has been accounted for as an operating lease. The lease term is five years.

In September 2010, CONSOL Energy completed a sale-leaseback of longwall shields for the Enlow Fork Mine. Cash proceeds from the sale were $14,551, which was the same as our basis in the equipment. Accordingly, no gain or loss was recognized on the transaction. The lease has been accounted for as an operating lease. The lease term is five years.

In June 2010, CONSOL Energy paid Yukon Pocahontas Coal Company $30,000 cash to acquire certain coal reserves and $20,000 cash in advanced royalty payments recoupable against future production. Both payments were made per a settlement agreement in regards to the depositing of untreated water from the Buchanan Mine, a mine operated by one of our subsidiaries, into the void spaces of the nearby mines of one of our other subsidiaries, Island Creek Coal Company.

On June 1, 2010, CONSOL Energy completed the acquisition of CNX Gas Corporation (CNX Gas) outstanding common stock for a cash payment of $966,811 pursuant to a tender offer followed by a short-form merger in which CNX Gas became a wholly owned subsidiary of CONSOL Energy (CNX Gas Acquisition). All of the shares of CNX Gas that were not already owned by CONSOL Energy were acquired at a price of $38.25 per share. CONSOL Energy previously owned approximately 83.3% of the approximately 151 million shares of CNX Gas common stock outstanding. An additional $24,223 cash payment was made to cancel previously vested but unexercised CNX Gas stock options. CONSOL Energy financed the acquisition of CNX Gas shares by means of internally generated funds, borrowings under its credit facilities and proceeds from its offering of common stock.

On April 30, 2010, CONSOL Energy completed the acquisition of the Appalachian oil and gas exploration and production business of Dominion Resources, Inc. (Dominion Acquisition) for a cash payment of $3,470,212 which was principally allocated to oil & gas properties, wells and well-related equipment. The acquisition, which was accounted for under the acquisition method of accounting, included approximately 1 trillion cubic feet equivalents (Tcfe) of net proved reserves and 1.46 million net acres of oil and gas rights within the Appalachian Basin. Included in the acreage holdings were approximately 500 thousand prospective net Marcellus Shale acres located predominantly in southwestern Pennsylvania and northern West Virginia. Dominion is a producer and transporter of natural gas as well as a provider of electricity and related services. The acquisition enhanced CONSOL Energy’s position in the strategic Marcellus Shale fairway by increasing its development assets.
The results of operations of the acquired entities are included in CONSOL Energy's Consolidated Statements of Income as of May 1, 2010. Net revenues and net income (loss) resulting from the Dominion Acquisition that were included in CONSOL Energy's operating results were $133,850 and $(5,364), respectively, for the year ended December 31, 2010.

The unaudited pro forma results for the year ended December 31, 2010, assuming the acquisition had occurred at January 1, 2010, are presented below. Pro forma adjustments include estimated operating results, transaction and financing fees incurred, additional interest related to the $2.75 billion of senior unsecured notes and 44,275,000 shares of common stock issued in connection with the transaction.

	Year Ended December 31, 2010
Total Revenue and Other Income	$5,303,008
Earnings Before Income Taxes	$414,205
Net Income Attributable to CONSOL Energy Inc. Shareholders	$314,760
Basic Earnings Per Share	$1.39
Dilutive Earnings Per Share	$1.38

The pro forma results are not necessarily indicative of what actually would have occurred if the Dominion Acquisition had been completed as of January 1, 2010, nor are they necessarily indicative of future consolidated results.
CONSOL Energy incurred $65,363 of acquisition-related costs as a direct result of the Dominion Acquisition and CNX Gas Acquisition for the year ended December 31, 2010. These expenses have been included within Transaction and Financing Fees on the Consolidated Statements of Income for the year ended December 31, 2010.
In March 2010, CONSOL Energy completed the sale of the Jones Fork Mining Complex as part of a litigation settlement with Kentucky Fuel Corporation. No cash proceeds were received and $10,482 of litigation settlement expense was recorded in Cost of Goods Sold and Other Operating Charges for the year ended December 31, 2010. The loss recorded was net of $8,700 related to the fair value of estimated amounts to be collected related to an overriding royalty on future mineable and merchantable coal extracted and sold from the property.

NOTE 3—OTHER INCOME:

	For the Years Ended December 31,		
	2012	2011	2010
Gain on disposition of assets (a)	$282,235	$46,497	$9,908
Interest income	28,937	8,919	7,642
Equity in earnings of affiliates	27,048	24,663	21,428
Royalty income	16,865	18,491	14,688
Service income	9,029	9,059	9,796
Right-of-way issuance	5,030	13,519	122
Other	40,560	32,472	33,923
Total Other Income	$409,704	$153,620	$97,507

(a) See Note 2 - Acquisitions and Dispositions for additional information.

NOTE 4—INTEREST EXPENSE:

	For the Years Ended December 31,		
	2012	2011	2010
Interest on debt	$256,800	$264,080	$213,832
Interest on other payables	1,314	(189)	4,593
Interest capitalized	(38,054)	(15,547)	(13,393)
Total Interest Expense	$220,060	$248,344	$205,032

Interest on other payables for the year ended December 31, 2012 includes a reversal of interest expense of $543 related to uncertain tax positions. See Note 6–Income Taxes, for further discussion.

NOTE 5—TAXES OTHER THAN INCOME:

	For the Years Ended December 31,		
	2012	2011	2010
Production taxes	$201,906	$220,857	$202,536
Property taxes	68,145	58,117	57,889
Payroll taxes	58,286	59,186	54,631
Capital stock & franchise tax	8,378	3,670	11,201
Virginia employment enhancement tax credit	(4,311)	(6,109)	(4,777)
Other	4,251	8,739	6,978
Total Taxes Other Than Income	$336,655	$344,460	$328,458

NOTE 6—INCOME TAXES:

Income taxes (benefits) provided on earnings consisted of:

	For The Years Ended December 31,		
	2012	2011	2010
Current:			
U.S. Federal	$75,579	$173,912	$82,031
U.S. State	8,677	34,555	13,652
Non-U.S	31,594	—	(3,425)
	115,850	208,467	92,258
Deferred:			
U.S. Federal	(6,717)	(35,487)	8,463
U.S. State	(1,697)	(17,524)	8,566
Non-U.S.	1,765	—	—
	$(6,649)	$(53,011)	$17,029
Total Income Taxes	$109,201	$155,456	$109,287

The components of the net deferred tax assets are as follows:

	December 31, 2012	2011
Deferred Tax Assets:		
Postretirement benefits other than pensions	$1,136,495	$1,217,246
Mine closing	107,418	95,193
Alternative minimum tax	54,609	54,998
Pneumoconiosis benefits	70,141	69,915
Workers' compensation	68,339	65,266
Salary retirement	83,077	103,146
Net operating loss	59,797	57,669
Mine subsidence	35,332	41,453
Reclamation	26,716	23,738
Capital lease	23,103	24,763
Other	149,435	136,211
Total Deferred Tax Assets	1,814,462	1,889,598
Valuation Allowance**	(41,136)	(41,016)
Net Deferred Tax Assets	1,773,326	1,848,582
Deferred Tax Liabilities:		
Property, plant and equipment	(1,084,246)	(1,046,235)
Gas hedge	(51,006)	(98,539)
Advance mining royalties	(33,950)	(31,284)
Other	(11,435)	(23,717)
Total Deferred Tax Liabilities	(1,180,637)	(1,199,775)
Net Deferred Tax Assets	$592,689	$648,807

**Valuation allowance of ($41,136) has been allocated to long-term deferred tax asset for 2012. Valuation allowance of ($41,016) has been allocated to long-term deferred tax asset for 2011.

A valuation allowance is required when it is more likely than not that all or a portion of a deferred tax asset will not be realized. All available evidence, both positive and negative, must be considered in determining the need for a valuation allowance. At December 31, 2012 and 2011, positive evidence considered included financial and tax earnings generated over the past three years for certain subsidiaries, future income projections based on existing fixed price contracts and forecasted expenses, reversals of financial to tax temporary differences and the implementation of and/or ability to employ various tax planning strategies. Negative evidence included financial and tax losses generated in prior periods and the inability to achieve forecasted results for those periods. CONSOL Energy continues to report, on an after federal tax basis, a deferred tax asset related to state operating losses of $59,797 with a related valuation allowance of $35,827 at December 31, 2012. The deferred tax asset related to state operating losses, on an after tax adjusted basis, was $57,669 with a related valuation allowance of $34,980 at December 31, 2011. A review of positive and negative evidence regarding these tax benefits concluded that the valuation allowances for various CONSOL Energy subsidiaries was warranted. The net operating losses expire at various times between 2013 and 2031.

The deferred tax assets attributable to future deductible temporary differences for certain CONSOL Energy subsidiaries with histories of financial and tax losses was also reviewed for positive and negative evidence regarding the realization of the deferred tax assets. A valuation allowance of $5,309 and $6,036 on an after federal tax adjusted basis has also been recorded for 2012 and 2011, respectively. In 2012, there were no future deductible temporary differences included in the valuation allowance against the deferred state tax assets. Included in the valuation allowance against the deferred state tax assets attributable to future deductible temporary differences for 2011 are

$872 of allowances which were recognized through Other Comprehensive Income. These allowances relate to actuarial gains/losses for other postretirement, pension and long-term disability benefits in state jurisdictions which are subject to a full valuation allowance. No allowances were recognized through other comprehensive income in 2012. Management will continue to assess the potential for realizing deferred tax assets based upon income forecast data and the feasibility of future tax planning strategies and may record adjustments to valuation allowances against deferred tax assets in future periods as appropriate, that could materially impact net income.

During 2012, the deferred tax asset relating to federal alternative minimum tax decreased $389. This change was due to 2012 business activity, the 2011 accrual to 2011 return adjustments, and foreign tax credits claimed on amended returns.

The following is a reconciliation stated as a percentage of pretax income, of the United States statutory federal income tax rate to CONSOL Energy's effective tax rate:

	For the Years Ended December 31,					
	2012		2011		2010	
	Amount	Percent	Amount	Percent	Amount	Percent
Statutory U.S. federal income tax rate	$174,047	35.0 %	$275,784	35.0 %	$163,770	35.0 %
Excess tax depletion	(72,028)	(14.5)	(91,470)	(11.6)	(70,812)	(15.1)
Effect of medicare prescription drug, improvement and modernization act of 2003	2,112	0.4	2,112	0.3	2,113	0.4
Effect of domestic production activities	(10,267)	(2.0)	(22,209)	(2.8)	(5,633)	(1.2)
Federal and state tax accrual to tax return reconciliation	6,004	1.2	2,257	0.3	4,609	1.0
IRS and state tax examination settlements	(925)	(0.2)	(5,188)	(0.7)	—	—
Net effect of state income taxes	4,479	0.9	14,197	1.8	12,022	2.6
Effect of releasing valuation allowance	—	—	(22,618)	(2.9)	—	—
Effect of foreign tax	1,765	0.4	(1,822)	(0.2)	(3,424)	(0.7)
Other	4,014	0.8	4,413	0.5	6,642	1.4
Income Tax Expense / Effective Rate	$109,201	22.0 %	$155,456	19.7 %	$109,287	23.4 %

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 reduction to income tax expense. The transaction is reflected in the IRS and state tax examination settlements line of the rate reconciliation.

CONSOL Energy recognized additional tax expense as a result of changes in estimates of percentage depletion and Domestic Production Activities Deduction related to a prior-year tax provision. The result of these changes was a tax increase of $6,004.

CONSOL Energy was advised 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. In addition CONSOL will be filing amended returns for the tax years 2003-2010 which will result in additional foreign tax credit of $3,765. These transactions were reflected in the Effect of foreign tax line of the rate reconciliation.

142

A reconciliation of the beginning and ending gross amounts of unrecognized tax benefits is as follows:

	For the Years Ended December 31,	
	2012	2011
Balance at beginning of period	$37,586	$91,349
Increase in unrecognized tax benefits resulting from tax positions taken during current period	—	—
Increase (decrease) in unrecognized tax benefits resulting from tax positions taken during prior periods	—	—
Reduction in unrecognized tax benefits as a result of the lapse of the applicable statute of limitations	(2,800)	(17,362)
Reduction of unrecognized tax benefits as a result of a settlement with taxing authorities	—	(36,401)
Balance at end of period	$34,786	$37,586

If these unrecognized tax benefits were recognized, $2,071 and $3,891, respectively, would affect CONSOL Energy's effective income tax rate.

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

In 2012, CONSOL Energy recognized a reduction in unrecognized tax benefits as a result of the lapse of a statute of limitations. The resulting decrease in liabilities is a decrease to state income tax for 2012 of $2,800 net of Federal impact of $980. In 2013, the IRS is continuing its audit of tax years 2008 and 2009. During the next year, the statute of limitations for assessing additional income tax deficiencies will expire for certain tax years in several state tax jurisdictions. The expiration of the statute of limitations for these years will have an insignificant impact on CONSOL Energy's total uncertain income tax positions and net income for the twelve-month period.

CONSOL Energy recognizes interest accrued related to unrecognized tax benefits in its interest expense. At December 31, 2012 and 2011, the Company had an accrued liability of $4,831 and $5,373 respectively, for interest related to uncertain tax positions of which $543 and $3,096 was recorded as income for the years ended December 31, 2012 and 2011, respectively. Interest expense was reduced $2,265 during the year ended December 31, 2012 due to the reversal of uncertain tax liabilities due to the expiration of the statute. During the year ended December 31, 2012, CONSOL Energy paid no interest related to income tax deficiencies.

CONSOL Energy recognizes penalties accrued related to unrecognized tax benefits in its income tax expense. As of December 31, 2012 and 2011, there were no accrued penalties recognized.

NOTE 7—MINE CLOSING, RECLAMATION & GAS WELL CLOSING:

CONSOL Energy accrues for reclamation, mine closing costs, perpetual water care costs and dismantling and removing costs of gas related facilities using the accounting treatment prescribed by the Asset Retirement and Environmental Obligations Topic of the FASB Accounting Standards Codification. CONSOL Energy recognizes capitalized asset retirement costs by increasing the carrying amount of related long-lived assets, net of the associated accumulated depreciation. The obligation for asset retirements is included in Mine Closing, Reclamation, Gas Well Closing and Other Accrued Liabilities on the Consolidated Balance Sheets.

143

The reconciliation of changes in the asset retirement obligations at December 31, 2012 and 2011 is as follows:

	As of December 31,	
	2012	2011
Balance at beginning of period	$650,073	$670,856
Accretion expense	49,332	48,120
Payments	(40,242)	(57,584)
Revisions in estimated cash flows	43,988	(4,621)
Dispositions	(4,139)	(6,698)
Balance at end of period	$699,012	$650,073

For the year ended December 31, 2012, Revisions in estimated cash flows include $40,610 related to additional reclamation and water treatment liabilities recognized at the Fola mining operation in West Virginia. As a result of market conditions, permitting issues, new regulatory requirements, and resulting changes in mine plans, the reclamation liability associated with the Fola operation was revised.

For the year ended December 31, 2012, Dispositions includes $(4,139) related to the sale of the non-producing Elk Creek property. See Note 2 - Acquisitions and Dispositions for additional details. For the year ended December 31, 2011, Dispositions included $(6,698) related to the sale of the Bishop operation.

NOTE 8—INVENTORIES:

Inventory components consist of the following:

	December 31,	
	2012	2011
Coal	$78,825	$105,378
Merchandise for resale	35,363	43,639
Supplies	133,578	109,318
Total Inventories	$247,766	$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 $19,700 and $22,406 at December 31, 2012 and December 31, 2011, respectively.

NOTE 9—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 December 31, 2012, there were letters of credit outstanding against the facility of $162,154. 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.

144

In accordance with the Transfers and Servicing Topic of the 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 $1,723, $1,986 and $2,676 for the years ended December 31, 2012, 2011 and 2010, 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 December 31, 2012 and 2011, eligible accounts receivable totaled $200,000 and $192,700, respectively. There was no subordinated retained interest at December 31, 2012 and there was $192,700 in subordinated retained interest at December 31, 2011. There were borrowings of $37,846 under the securitization facility recorded on the Consolidated Balance Sheets at December 31, 2012. There were no borrowings under the securitization facility recorded on the Consolidated Balance Sheets at December 31, 2011. Also, a $37,846 increase, $200,000 decrease and $150,000 increase in the accounts receivable securitization facility for the years ended December 31, 2012, 2011 and 2010, respectively, are reflected in the Net Cash (Used In) Provided By Financing Activities in the Consolidated Statements 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 10—PROPERTY, PLANT AND EQUIPMENT:

	December 31, 2012