CONSOL Energy Inc
Form 10-K
February 09, 2010
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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, 2009;

OR

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

For the transition period from _________

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.)

CNX Center

1000 CONSOL Energy Drive

Canonsburg, PA 15317-6506

(Address of principal executive offices including zip code)

Registrant s telephone number including area code: 724-485-4000

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 ¨

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 ¨ 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 ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every interactive data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes **x** No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 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. ¨

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 ¨   Non-accelerated filer ¨   Smaller reporting company ¨

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

The aggregate market value of voting stock held by nonaffiliates of the registrant as of June 30, 2009, 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 $6,131,030,034.

The number of shares outstanding of the registrant s common stock as of January 29, 2010 is 181,159,911 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of Consol Energy s Proxy Statement for the Annual Meeting of Shareholders to be held on May 4, 2010,

are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III.

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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, pr their negatives, or other similar 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:

- the continued weakness in global economic conditions or in any industry in which our customers operate, or sustained uncertainty in financial markets cause conditions we cannot predict;
- an extended decline in prices we receive for our coal and gas affecting our operating results and cash flows;
- reliance on customers honoring existing contracts, extending existing contracts or entering into new long-term contracts for coal;
- reliance on major customers;
- our inability to collect payments from customers if their creditworthiness declines;
- the disruption of rail, barge and other systems that deliver our coal;
- a loss of our competitive position because of the competitive nature of the coal and gas industries, or a loss of our competitive position because of overcapacity in these industries impairing our profitability;
- our inability to hire qualified people to meet replacement or expansion needs;
- 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;

the inability to produce a sufficient amount of coal to fulfill our customers requirements which could result in our customers initiating claims against us;

foreign currency fluctuations could adversely affect the competitiveness of our coal abroad;

the risks inherent in coal mining being subject to unexpected disruptions, including geological conditions, equipment failure, timing of completion of significant construction or repair of equipment, fires, accidents and weather conditions which could impact financial results;

increases in the price of commodities used in our mining operations could impact our cost of production;

obtaining governmental permits and approvals for our operations;

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the effects of proposals to regulate greenhouse gas emissions;

the effects of government regulation;

the effects of stringent federal and state employee health and safety regulations;

the effects of mine closing, reclamation and certain other liabilities;

uncertainties in estimating our economically recoverable coal and gas reserves;

the outcomes of various legal proceedings, which are more fully described in our reports filed under the Securities Exchange Act of 1934;

changes in existing federal and state income tax regulations;

increased exposure to employee related long-term 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;

our ability to comply with laws or regulations requiring that we post security for workers compensation and other statutory requirements;

acquisitions that we recently have made 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;

the anti-takeover effects of our rights plan could prevent a change of control;

risks in exploring for and producing gas;

new gas development projects and exploration for gas in areas where we have little or no proven gas reserves;

the disruption of pipeline systems which deliver our gas;

the availability of field services, equipment and personnel for drilling and producing gas;

replacing our natural gas reserves which if not replaced will cause our gas reserves and gas production to decline;

costs associated with perfecting title for gas rights in some of our properties;

other persons could have ownership rights in our advanced gas extraction techniques which could force us to cease using those techniques or pay royalties;

our ability to acquire water supplies needed for drilling, or our ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental rules;

the coalbeds and other strata from which we produce methane gas frequently contain impurities that may hamper production;

the enactment of severance tax on natural gas in states in which we operate may impact results of existing operations and impact the economic viability of exploiting new gas drilling and production opportunities;

location of a vast majority of our gas producing properties in three counties in southwestern Virginia, making us vulnerable to risks associated with having our gas production concentrated in one area;

our hedging activities may prevent us from benefiting from price increases and may expose us to other risks;

other factors discussed in our 2009 Form 10-K under Risk Factors, as updated by any subsequent Form 10-Qs, which are on file at the Securities and Exchange Commission.

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Item 1. ***Business.***

CONSOL Energy s History

We are a multi-fuel energy producer and energy services provider primarily serving the electric power generation industry in the United States. The electric power industry generates over two-thirds of its output by burning coal or gas, the two fuels we produce. During the year ended December 31, 2009, we produced high-British thermal unit (Btu) bituminous coal from 16 mining complexes in the United States. Coal produced from our mines has a high-Btu content which creates more energy per unit when burned compared to coals with lower Btu content. As a result, coals with greater Btu content can be more efficient to use. We are the majority shareholder (83.3%) of CNX Gas Corporation (CNX Gas). CNX Gas primarily produces pipeline-quality coalbed methane gas from our coal properties in the Northern and the Central Appalachian basin, and oil and gas from properties in the Appalachian and Illinois Basins. We believe that the use of coal and gas will continue to be the principal way in which the United States generates its electricity.

Historically, we rank among the largest coal producers in the United States based upon total revenue, net income and operating cash flow. Our production of approximately 59 million tons of coal in 2009 accounted for approximately 6% of the total tons produced in the United States and approximately 13% of the total tons produced east of the Mississippi River during 2009. We are one of the premier coal producers in the United States by several measures:

- We mine more high-Btu bituminous coal than any other United States producer;
- We are the largest coal producer east of the Mississippi River;
- We control the second largest amount of recoverable coal reserves among United States coal producers; and
- We are the largest United States producer of coal from underground mines.

Our subsidiary, CNX Gas, also ranks as one of the largest coalbed methane gas companies in the United States based on both its proved reserves and its current daily production. Our position as a gas producer is highlighted by several measures:

- Our principal coalbed methane operations produce gas from coal seams (single layers or strata of coal) with a high gas content;
- We produced 94.4 billion cubic feet of gas in the year ended December 31, 2009;
- At December 31, 2009, we had 3,926 net producing wells; and
- We controlled approximately 1.9 trillion cubic feet of net proved reserves at December 31, 2009, of which 86% were coalbed methane reserves.

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

CONSOL Energy was organized as a Delaware corporation in 1991. We use CONSOL Energy to refer to CONSOL Energy Inc. and our subsidiaries, unless the context otherwise requires.

Industry Segments

CONSOL Energy has two principal business units: Coal and Gas. The principal activities of the Coal unit are mining, preparation and marketing of steam coal, sold primarily to power generators, and of metallurgical coal, sold to steel and coke producers. The Coal unit includes four reportable segments. These reportable segments are Northern Appalachian, Central Appalachian, Metallurgical and Other Coal. Each of these reportable segments includes a number of operating segments (mines). For the year ended December 31, 2009,

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the Northern Appalachian aggregated segment includes the following mines: Blacksville #2, Robinson Run, McElroy, Loveridge, Bailey, Enlow Fork, Mine 84 and Shoemaker. For the year ended December 31, 2009, the Central Appalachian aggregated segment includes the following mines: Jones Fork Complex, the Miller Creek Complex, the Fola Complex and the Terry Eagle Complex. For the year ended December 31, 2009, the Metallurgical aggregated segment includes the following mines: Buchanan and Amonate Complex. The Other Coal segment includes our purchased coal activities, idled mine cost, coal segment business units not meeting aggregation criteria, as well as various other activities assigned to the coal segment but not allocated to each individual mine. The principal activity of the Gas unit is to produce pipeline-quality methane gas for sale primarily to gas wholesalers. CONSOL Energy s All Other segment includes terminal services, river and dock services, industrial supply services and other business activities, including rentals of building and flight operations. Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2009, 2008 and 2007 is included in Note 25 of Notes to Audited Consolidated Financial Statements included as Item 8 in Part II of this Annual Report on Form 10-K.

Coal Operations

Mining Complexes

During the year ended December 31, 2009, CONSOL Energy had 16 active mining complexes, including a 49% equity affiliate, all located in the United States.

The following map provides the location of CONSOL Energy s operations by region:

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The following table provides the location of CONSOL Energy s 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, 2009 and 2008

					As Received Heat Value(1) (Btu/lb)			Recoverable Reserves(2)			Recoverable Reserves
Mine/Reserve	**Location**	**Reserve Class**	**Coal Seam**	**Average Seam Thickness (feet)**	**Typical**	**Range**		**Owned (%)**	**Leased (%)**	**Tons in Millions 12/31/2009**	**(tons in Millions) 12/31/2008**
ASSIGNED OPERATING Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia)											
Enlow Fork	Enon, PA	Assigned	Pittsburgh	5.4	12,940	12,860	13,060	100%	%	48.9	160.3
		Accessible	Pittsburgh	5.3	12,900	12,830	13,000	79%	21%	197.9	185.3
Bailey	Enon, PA	Assigned	Pittsburgh	5.7	12,950	12,860	13,060	53%	47%	74.5	33.4
		Accessible	Pittsburgh	5.8	12,900	12,830	13,000	82%	18%	382.8	144.2
Mine 84	Eighty Four, PA	Assigned	Pittsburgh	5.4	13,120	12,950	13,250	100%	%	11.3	26.9
		Accessible	Pittsburgh	5.8	13,050	12,880	13,180	66%	34%	68.3	86.7
McElroy	Glen Easton, WV	Assigned	Pittsburgh	5.9	12,570	12,450	12,650	100%	%	195.0	201.5
		Accessible	Pittsburgh	5.8	12,530	12,410	12,610	94%	6%	153.0	69.0
Shoemaker	Moundsville, WV	Assigned	Pittsburgh	5.6	12,200	11,700	12,300	100%	%	48.4	60.2
		Accessible	Pittsburgh	5.6	12,250	11,990	12,390	100%	%	27.8	35.8
Loveridge	Fairview, WV	Assigned	Pittsburgh	7.5	13,150	13,070	13,370	84%	16%	37.9	47.0
		Accessible	Pittsburgh	7.6	13,100	13,020	13,320	95%	5%	13.6	25.7
Robinson Run	Shinnston, WV	Assigned	Pittsburgh	7.3	12,940	12,600	13,300	88%	12%	58.2	67.2
		Accessible	Pittsburgh	6.8	12,940	12,600	13,300	55%	45%	156.7	154.1
Blacksville #2	Wana, WV	Assigned	Pittsburgh	6.7	13,060	12,850	13,250	87%	13%	29.1	32.2
		Accessible	Pittsburgh	6.9	13,100	12,890	13,290	99%	1%	16.5	16.5
Harrison Resources(3)	Cadiz, OH	Assigned	Multiple	4.5	11,570	11,350	11,850	100%	%	9.2	9.6
Central Appalachia (Virginia, Southern West Virginia, Eastern Kentucky)											
Buchanan	Mavisdale, VA	Assigned	Pocahontas 3	5.7	13,980	13,700	14,200	19%	81%	68.4	39.9
		Accessible	Pocahontas 3	6.0	13,930	13,650	14,150	10%	90%	37.0	64.4
AMVEST Fola Complex	Bickmore, WV	Assigned	Multiple	6.1	12,380	12,250	12,550	96%	4%	101.7	104.0
AMVEST Terry Eagle Complex	Bickmore, WV	Assigned	Multiple	3.2	13,300	13,200	13,350	%	100%	22.7	22.8
Jones Fork Complex	Mousie, KY	Assigned	Multiple	3.2	12,530	12,450	12,650	74%	26%	35.1	35.8
		Accessible	Multiple	3.4	12,330	12,250	12,450	100%	%	1.4	1.4
Amonate Complex	Amonate, VA	Assigned	Multiple	3.8	13,100	12,850	13,350	70%	30%	19.6	19.6
Miller Creek Complex	Delbarton, WV	Assigned	Multiple	8.1	12,000	11,600	12,650	17%	83%	10.0	13.2
Western U.S. (Utah)											
Emery	Emery Co., UT	Assigned	Ferron I	7.5	12,260	12,000	13,000	79%	21%	16.9	16.9
Total Assigned Operating and Accessible								78%	22%	1,841.9	1,673.6

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(1) The heat value shown for assigned reserves is based on the quality of coal mined and processed during the year ended December 31, 2009. The heat value shown for accessible reserves is based on the same mining and processing methods as for the assigned reserves with adjustments made based on the variability found in exploration drill core samples. The heat values given have been adjusted to include moisture that may be added during mining or processing and 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 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) Harrison Resources is an equity affiliate in which CONSOL Energy owns a 49% interest. Reserves reported equal CONSOL Energy s 49% proportionate interest in Harrison Resources reserves.

Excluded from the table above are approximately 109.2 million tons of reserves at December 31, 2009 that are assigned to projects that have not produced coal in 2009 or 2008. These assigned reserves are in the Northern Appalachia (northern West Virginia), Central Appalachia (Virginia and eastern Kentucky) and Illinois Basin (Illinois) regions. These reserves are approximately 52% owned and 48% 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 unassigned 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 reflects 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, 2009, CONSOL Energy had an estimated 4.5 billion tons of proven and probable reserves. 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 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 mile 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. The independent consultant has reviewed the procedures used by us to prepare our internal estimates, verified the accuracy of approximately 97% 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 power generation.

CONSOL Energy s reserves are located in northern Appalachia (62%), central Appalachia (14%), the mid-western United States (18%), the western United States (4%), and in western Canada (2%) at December 31, 2009.

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

CONSOL Energy UNASSIGNED Recoverable Coal Reserves as of 12/31/09

Coal Producing Region	As Received Heat Value(1) (Btu/lb)	Recoverable Reserves 12/31/09(2) Owned (%)	Leased (%)	Tons (in millions)	Recoverable Reserves (tons in millions) 12/31/2008
Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia)	11,400 13,500	70%	30%	1,239.7	1,437.1
Central Appalachia (Virginia, Southern West Virginia, Eastern Kentucky)	11,900 14,200	43%	57%	301.4	264.5
Illinois Basin (Illinois, Western Kentucky, Indiana)	11,500 11,900	43%	57%	780.6	780.6
Western U.S. (Wyoming)	9,400	100%	%	169.1	169.1
Western Canada (Alberta)	12,400 12,900	%	100%	77.9	77.9
Total		**62%**	**38%**	**2,568.7**	**2,729.2**

(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, Western U.S. and Western Canada 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.

The following table summarizes our proven and probable reserves as of December 31, 2009 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.

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CONSOL ENERGY PROVEN AND PROBABLE RECOVERABLE COAL RESERVES

BY PRODUCING REGION AND PRODUCT (IN MILLIONS OF TONS) AS OF DECEMBER 31, 2009

	£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**	**Percentage By Region**
Northern Appalachia:											
Metallurgical:											
High Vol A Bituminous						162.3				162.3	3.6%
Steam:											
High Vol A Bituminous						111.0	54.4	123.4	2,328.0	2,616.8	57.9%
Low Vol Bituminous						33.6				33.6	0.7%
Region Total						306.9	54.4	123.4	2,328.0	2,812.7	62.2%
Central Appalachia:											
Metallurgical:											
High Vol A Bituminous	33.6	4.9	22.6			18.3			1.3	80.7	1.8%
Med Vol Bituminous	0.5	2.8	82.3							85.6	1.9%
Low Vol Bituminous			124.5	2.3		26.2				153.0	3.4%
Steam:											
High Vol A Bituminous	38.3	73.4	14.1	61.6	46.2	61.7	0.8	2.5	5.2	303.8	6.8%
Region Total	72.4	81.1	243.5	63.9	46.2	106.2	0.8	2.5	6.5	623.1	13.9%
Midwest Illinois Basin:											
Steam:											
High Vol B Bituminous					79.4			460.6		540.0	12.0%
High Vol C Bituminous					159.5		108.3			267.8	5.9%
Region Total					238.9		108.3	460.6		807.8	17.9%
Northern Powder River Basin:											
Steam:											
Sub bituminous B			169.1							169.1	3.7%
Region Total			169.1							169.1	3.7%
Utah Emery Field:											
High Vol B Bituminous		16.9			12.3					29.2	0.6%
Region Total		16.9			12.3					29.2	0.6%
Western Canada:											
Metallurgical:											
Med Vol Bituminous	30.2	47.7								77.9	1.7%
Region Total	30.2	47.7								77.9	1.7%
Total Company	102.6	145.7	412.6	63.9	297.4	413.1	163.5	586.5	2,334.5	4,519.8	100.0%
Percent of Total	2.3%	3.2%	9.1%	1.4%	6.6%	9.1%	3.6%	13.0%	51.7%	100.0%	

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CONSOL ENERGY PROVEN AND PROBABLE RECOVERABLE COAL RESERVES BY PRODUCT

(MILLIONS OF TONS) AS OF DECEMBER 31, 2009

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 medium and low volatile which is based on fixed carbon and volatile matter.

	£1.20 lbs S02/MMBtu			> 1.20 £ 2.50 lbs S02/MMBtu			> 2.50 lbs S02/MMBtu				
By Product	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Total**	**Percentage By Product**
Metallurgical:											
High Vol A Bituminous	33.6	4.9	22.6			180.6			1.3	243.0	5.4%
Med Vol Bituminous	30.7	50.5	82.3							163.5	3.6%
Low Vol Bituminous			124.5	2.3		26.2				153.0	3.4%
Total Metallurgical	64.3	55.4	229.4	2.3		206.8			1.3	559.5	12.4%
Steam:											
High Vol A Bituminous	38.3	73.4	14.1	61.6	46.2	172.7	55.2	125.9	2,333.2	2,920.6	64.6%
High Vol B Bituminous		16.9			91.7			460.6		569.2	12.6%
High Vol C Bituminous					159.5		108.3			267.8	5.9%
Low Vol Bituminous						33.6				33.6	0.8%
Sub bituminous B			169.1							169.1	3.7%
Total Steam	38.3	90.3	183.2	61.6	297.4	206.3	163.5	586.5	2,333.2	3,960.3	87.6%
Total	102.6	145.7	412.6	63.9	297.4	413.1	163.5	586.5	2,334.5	4,519.8	100.0%
Percent of Total	2.3%	3.2%	9.1%	1.4%	6.6%	9.1%	3.6%	13.0%	51.7%	100.0%	

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	< 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

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 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 sulfur dioxide standards may not meet an emission standard for a different pollutant such as mercury. Moreover, the term compliance coal is always used with reference to the then-current regulatory limit. Clean air regulations that further restrict sulfur dioxide emissions will likely reduce significantly 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, 2009, 0.7 billion tons, or 15%, of our coal reserves met the current standard as a compliance coal. It is possible that no coal will be considered compliance coal with emission standards restricted to a level that requires emissions-control technology to be used regardless of the coal s sulfur content. In many cases, our customers have responded to compliance coal 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, our customers are less concerned about the sulfur content of our coal.

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As a result of a 1998 court decision forcing the establishment of mercury emissions standards for power plants, the Environmental Protection Agency (EPA) also promulgated 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 per million British thermal unit 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 British thermal units) 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 captured by scrubbers installed for sulfur control) than sub-bituminous coal, including coals produced in the Powder River Basin. High rank coals are also amenable to other methods of controlling mercury emissions, such as by powdered activated carbon injection. The EPA s proposed control of mercury was recently vacated by a federal court requiring the EPA to develop a new proposal on mercury controls. Prior to federal court action, some states have already adopted a control program for mercury.

Production

In the year ended December 31, 2009, 91% of CONSOL Energy s production came from underground mines and 9% 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, 2009, 87% 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 low incremental cost.

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The following table shows the production, in millions of tons, for CONSOL Energy s mines in the years ended December 31, 2009, 2008 and 2007, the location of each mine, the type of mine, the type of equipment used at each mine and the year each mine was established or acquired by us.

Mine	Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in millions) 2009	2008	2007	Year Established or Acquired
Northern Appalachia								
Enlow Fork	Enon, Pennsylvania	U	LW/CM	R R/B	11.1	11.1	11.2	1990
Bailey	Enon, Pennsylvania	U	LW/CM	R R/B	10.4	10.0	9.9	1984
McElroy	Glen Easton, West Virginia	U	LW/CM	B	9.9	9.6	9.7	1968
Loveridge	Fairview, West Virginia	U	LW/CM	R T	6.0	5.2	6.6	1956
Robinson Run	Shinnston, West Virginia	U	LW/CM	R CB	5.6	5.6	6.5	1966
Blacksville 2(1)	Wana, West Virginia	U	LW/CM	R R/B T	3.8	5.6	5.1	1970
Mine No. 84(1)	Eighty Four, Pennsylvania	U	LW/CM	R R/B T	0.5	1.8	3.6	1998
Shoemaker(2)	Moundsville, West Virginia	U	LW/CM	B	0.4	1.1		1966
Harrison Resource Corporation(3)(4)	Cadiz, Ohio	S	S/L	R T	0.4	0.2	0.1	2007
Central Appalachia								
Miller Creek Complex(3)	Delbarton, West Virginia	U/S	CM/S/L	T	3.2	3.1	1.4	2004
AMVEST-Fola Complex(1)(3)(5)	Bickmore, West Virginia	U/S	A S/L CM	R	3.0	3.9	1.8	2007
Buchanan(1)(6)	Mavisdale, Virginia	U	LW/CM	R	2.8	3.5	2.8	1983
Jones Fork Complex(1)(3)	Mousie, Kentucky	U/S	CM	R T	1.1	2.5	3.1	1992
Amonate Complex(1)	Amonate, Virginia	U/S	CM/S/L	R T		0.4	0.6	1925
AMVEST-Terry Eagle Complex(5)	Jodie, West Virginia	U/S	CM A S/L	R T		0.4	0.1	2007
Mill Creek(3)(7)	Deane, Kentucky	U/S	CM	R			1.1	1994
Western U.S.								
Emery	Emery County, Utah	U	CM	T	1.2	1.1	1.0	1945

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 ended December 31, 2009 due to market conditions.
(2) Mine was idled throughout most of 2009 due to converting from track haulage, to more efficient belt haulage to remove coal from the mine.
(3) Harrison Resource Corporation, Miller Creek, Amvest Fola, Jones Fork and Mill Creek Complex include facilities operated by independent mining contractors.
(4) Production amounts represent CONSOL Energy s 49% ownership interest.
(5) Mine Acquired in AMVEST Corporation acquisition on July 31, 2007.

(6) Buchanan Mine was idled for part of the year ended December 31, 2008 and part of the year ended December 31, 2007 after several roof falls in previously mined areas damaged some of the ventilation controls inside the mine.
(7) Mine was sold in February 2008.

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

	Years Ended December 31, 2009	2008	2007
Average Sales Price Per Ton Produced	$ 58.28	$ 48.77	$ 40.60

Construction on a new slope, overland belt and underground belt haulage system at our Shoemaker Mine in West Virginia was completed. The mine began production using the entire system in mid-January 2010. Construction of a new slope and overland belt at the Bailey Mine in Pennsylvania continued during 2009. The project is expected to be complete by the end of March 2010. Both projects are expected to improve productivity, increase production, reduce costs and enhance safety. 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 the overland belts because older underground belt areas will be sealed.

The Buchanan Mine preparation plant was upgraded. The upgrades included an increase in capacity, construction of a second raw coal silo and an upgrade of the conveyor belt system at the preparation plant. The project was completed in August and has performed as expected. Also, construction of a reverse osmosis water treatment system (RO) was started during 2009. The RO system will provide a constant water source to the Buchanan preparation plant and provide water needed in the underground coal production at the mine. Construction of the RO is expected to be completed in the third quarter of 2010.

Title to coal properties that we lease or purchase and the boundaries of these properties are verified at the time we lease or acquire the properties by law firms retained by us. 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, 2009, 2008 and 2007.

Year	Total Royalty Tonnage (in thousands)	Total Coal Acreage Leased	Total Royalty Income (in thousands)
2009	11,403	232,181	$ 16,448
2008	11,757	218,273	$ 18,775
2007	13,909	218,089	$ 11,362

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.

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The following table ranks the 20 largest underground mines in the United States by tons of coal produced in calendar year 2008.

MAJOR U.S. UNDERGROUND COAL MINES 2008

In millions of tons

Mine Name	Operating Company	Production
Enlow Fork	**CONSOL Energy**	**11.1**
Bailey	**CONSOL Energy**	**10.0**
McElroy	**CONSOL Energy**	**9.6**
Twenty Mile	Peabody Energy Subsidiary	8.6
SUFCO	Arch Coal, Inc.	7.4
Cumberland Resources	Cumberland Resources, LP. (Foundation)	7.3
Century	American Energy Corp. (Murray)	6.9
Emerald Resources	Emerald Resources, LP. (Foundation)	6.3
San Juan	BHP Billiton	6.3
West Elk	Arch Coal, Inc.	6.1
Powhatan No. 6	The Ohio Valley Coal Company (Murray)	5.7
Robinson Run	**CONSOL Energy**	**5.6**
Blacksville 2	**CONSOL Energy**	**5.6**
Loveridge	**CONSOL Energy**	**5.2**
Warrier	Warrier Coal, LLC (Alliance)	5.1
Elk Creek	Oxbow Mining, LLC	4.9
Dotiki	Webster County Coal LLC (Alliance)	4.7
Dugout Canyon	Arch Coal, Inc.	4.3
Mountaineer 11/Mtn. Laurel	Arch Coal, Inc.	4.0
Highland	Highland Mining Co. LLC (Patriot)	3.9

Source: National Mining Association

Marketing and Sales

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 Atlanta, Philadelphia and Pittsburgh. In addition, we sell coal through agents and to brokers and unaffiliated trading companies. In 2009, we sold 58.1 million tons of coal, including our portion of equity affiliates. Eighty-eight percent (88%) of these sales were sold in domestic markets. Our direct sales to domestic electricity generators represented 83% of our total tons sold in 2009. We had approximately 90 customers in 2009. During 2009, no coal customers individually accounted for more than 10% of total revenue. However, the top four coal customers accounted for more than 25% of our total revenues.

Coal Contracts

We sell coal to customers under arrangements that are the result of both bidding procedures and unsolicited offers leading to extensive negotiations. We sell coal for terms that range from a single shipment to multi-year agreements for millions of tons. During the year ended December 31, 2009, approximately 90% of the coal we produced was sold under contracts with terms of one year or more. The pricing mechanisms under our multiple-year agreements typically consist of contracts with one or more of the following pricing mechanisms:

Fixed price contracts with pre-established prices; or

Periodically negotiated prices that reflect market conditions at the time or are 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.

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Several contracts provide the opportunity to periodically adjust the contract prices. Contract prices may be adjusted as often as quarterly based upon indices which are pre-negotiated. Most of our contracts have terms no longer than five years. However, some of our contracts range in term from seven years to twenty years.

The following table sets forth, as of January 20, 2010, the total tons of coal CONSOL Energy is committed to deliver from 2010 through 2014.

	Tons/Dollars of Coal to be Delivered (Tons in millions of nominal tons)				
	2010	2011	2012	2013	2014
Committed tons without pricing	1.3	18.3	20.9	22.1	22.1
Committed tons with firm pricing	59.7*	24.1	8.2	4.2	0.3
Average realized price	$ 55.06	$ 51.92	$ 51.45	$ 49.14	$ 57.36
Committed tons priced with collars		6.0	5.8	7.3	9.5
Average ceiling		$ 63.46	$ 51.61	$ 51.38	$ 52.00
Average floor		$ 53.93	$ 41.75	$ 38.13	$ 37.18

* 2010 Tons committed and priced include 3.1 million tons of metalurgical coal at a price of $96.00 per ton.

We routinely engage in efforts 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.

Contracts also typically contain force majeure provisions allowing for the suspension of performance by the customer or us for the duration of specified events beyond the control of the affected party, including labor disputes and extraordinary geological conditions. Some contracts may terminate upon continuance of an event of force majeure for an extended period, which is generally three to twelve months. Contracts also typically specify minimum and maximum quality specifications regarding the coal to be delivered. Failure to meet these conditions could result in price reductions, damages, suspension of deliveries or termination of the contract, at the election of the customer. Although the volume to be delivered under a long-term contract is stipulated, we or the buyer may vary the timing of delivery within specified limits.

Distribution

Coal is transported from CONSOL Energy s mining complexes to customers by means of 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. Most customers negotiate their own freight contracts.

At December 31, 2009 we operated 24 towboats, 5 harbor boats and a fleet of more than 650 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.

Competition

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. CONSOL Energy competes against other large producers and hundreds of small producers in the United States and overseas. The five largest producers are estimated by the 2008 National Mining Association Survey to have produced approximately 53% (based on tonnage produced) of the total United States production in 2008. The U.S. Department of Energy reported 1,435 active coal mines in the United States in 2008, the latest year for which government statistics are available. Demand for our coal by our principal customers is affected by:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power;

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- coal quality;
- transportation costs from the mine to the customer; and
- the reliability of fuel supply.

Continued demand for CONSOL Energy s coal and the prices that CONSOL Energy obtains are affected by demand for electricity, environmental and government regulation, technological developments 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 market, both of which are significantly affected by international demand and competition.

Gas Operations

Our gas operations are primarily conducted by CNX Gas Corporation (CNX Gas), an 83.3% owned subsidiary of CONSOL Energy. Information presented below is 100% of CNX Gas basis; it does not include 16.7% noncontrolling interest reduction. CNX Gas primarily produces coalbed methane, which is gas that resides in coal seams. In the eastern United States, conventional natural gas fields typically are located in various types of sedimentary formations at depths ranging from 2,000 to 15,000 feet. Exploration companies often put their capital at risk by searching for gas in commercially exploitable quantities at these depths. By contrast, gas in the coal seams that we drill or anticipate drilling is typically in formations less than 2,500 feet deep which are usually better defined than deeper formations. CNX Gas believes that this contributes to lower exploration costs than those incurred by producers that operate in deeper, less defined formations. However, we have continued to increase our exploratory efforts in the shale and deeper formations.

CNX Gas has not filed reserve estimates with any federal agency.

Areas of Operation

In the Appalachian Basin we operate principally in Central Appalachia and Northern Appalachia. We also operate in the Illinois Basin. Our primary operating areas are:

- Central Appalachia, Virginia Operations coalbed methane (CBM), in Southwest Virginia, our traditional and largest area of operation, where we have typically produced CBM from vertical wells which we drill ahead of mining and gob gas wells;
- Northern Appalachia, Mountaineer CBM in northwestern West Virginia and southwestern Pennsylvania where we drill vertical-to-horizontal CBM wells;
- Northern Appalachia, Nittany CBM in central Pennsylvania, where we drill vertical CBM wells;
- Northern Appalachia, Mountaineer-Conventional, in northwest West Virginia and southwest Pennsylvania, where we continue development in the Marcellus Shale and shallow conventional zones;
- Northern Appalachia, Buckeye-Conventional in southeastern and central Ohio where we have begun drilling vertical exploration wells in the Marcellus and shallow conventional zones;
- Tennessee, Knox-Chattanooga Shale, in eastern Tennessee, where we intend to convert our horizontal exploration program in the Chattanooga Shale into a full scale development program; and

- Illinois Basin, Cardinal, in western Kentucky, Indiana and Illinois, where we are conducting an exploration program in the New Albany Shale and shallow oil zones.

In addition to the above areas, we believe we have Appalachian shale potential in the Huron shale. Additional potential exists in the Trenton Black River formation which is thought to underlie nearly all of the Appalachian shales. We will continue to evaluate our acreage position in these areas with the continuation of our exploration program.

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Central Appalachia

Virginia Operations CBM

We have the rights to extract CBM in this region from approximately 405,000 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 over 1,300 core holes that allow us to determine the amount of coal present, the geologic structure of the coal seam and the gas content of the coal.

We coordinate some of our CBM extraction with the subsurface coal mining of our Buchanan Mine. The initial phase of CBM extraction involves drilling a traditional vertical wellbore into the coal seam in advance of future mining activities. In general, we drill these wells into the coal seam ahead of the planned coal mining recovery in an area. To stimulate the flow of CBM to the wellbore, we fracture the coal seam by pumping water or inert gases into the coal seam. Once established, these fractures are maintained by further forcing sand into the fractures to keep them from closing, allowing CBM to desorb from the coal and migrate along the series of fractures into the wellbore. We refer to this type of well as a frac well. In 2009, frac wells account for approximately 76% of our Virginia production.

Because some of our gas is produced in association with subsurface mining, we have a unique opportunity to evaluate the effectiveness of our fracture techniques. We can enter the coal mine and inspect the fracture pattern created in the seam as the mining process exposes more of the coal. As a result, we have had the opportunity to gain insight into the efficiency of our fracturing techniques that is not available in a conventional production scenario. We have used this knowledge to modify and improve the effectiveness of our fracturing techniques.

Eventually, subsurface mining activities will mine through the frac wells that are drilled in advance of the mine development plan. As the main coal seam is removed from an area (called a panel), a rubble zone (called gob) is formed in the cavity created by the extraction of the coal. When the coal is removed, the rock above collapses into the void. These upper seams become extensively fractured and release substantial volumes of gas. We drill vertical wells (called gob wells) into the gob to extract the additional gas that is released. Approximately 10% of our 2009 Virginia gas production came from gob gas from active coal operations.

We also drill long horizontal wellbores into the coal seam from within active mines. We strategically locate these horizontal wells within the pattern of existing frac wells to further accelerate the desorption of CBM from the coal seam. We have drilled 15 of these in-mine horizontal wells, some of which have been extended to lengths of 5,000 feet. These wells show that a more efficient recovery of gas in place is possible ahead of mining operations. In-mine horizontal wells accounted for approximately 1% of Virginia production in 2009.

Virginia Operations Shale and Tight Sands

We have 224,000 net acres of Huron shale potential in Kentucky and Virginia; a portion of this acreage has tight sands potential.

Tennessee

The Chattanooga Shale in Tennessee is a Devonian-age shale found at a depth of approximately 3,500 feet. Shale thickness is between 40-80 feet, but CNX Gas has found it to be rich in total organic content. CNX Gas has 269,000 net acres of Chattanooga Shale. This largely contiguous acreage is composed of only a small number of leases, a rarity in Appalachia. CNX Gas is the operator of all of its Chattanooga Shale wells. CNX Gas believes that we drilled the first successful horizontal Chattanooga Shale well and that we have currently drilled more horizontal wells than any other operator in this play.

Northern Appalachia

Mountaineer CBM

We have the right to extract CBM in this region from approximately 799,000 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 nearly 8,000 data points that allow us to determine the amount of coal present, the geologic structure of the coal seam and the gas content of the coal.

Due to the significant geological differences between the Pittsburgh #8 seam in Mountaineer and the Pocahontas #3 seam in Virginia, we have found that alternative extraction techniques are more effective than vertical frac wells in this area. Instead of using frac wells, we utilize well designs that rely on the application of vertical-to-horizontal drilling techniques. This well design includes a vertical wellbore that is intersected by a second well that has up to four horizontal lateral sections in the coal. Together, this well system facilitates extraction of CBM and water from the coal seam. The horizontal wellbores, extending up to 5,000 feet from the point of intersection with the vertical wellbore, expose large amounts of coal surface area allowing for the migration of water and CBM from the coal seam. The wells are spaced on approximately 480 acre sections. The vertical well, equipped with a mechanical pump, provides a sump for water produced by the coal seam to collect and enables the collected water to be lifted to the surface for disposal. In addition to our vertical-to-horizontal drilling, we also develop gob wells in this region associated with our coal mines.

Nittany CBM

We have the right to extract CBM in this region of Pennsylvania from approximately 260,000 net CBM acres, which contain most of our recoverable coal reserves as well as significant leases from other coal owners.

Marcellus Shale

We have substantially increased our acreage position in the Marcellus Shale from 186,000 net acres at December 31, 2008 to 250,000 net acres at December 31, 2009. We also have 161,000 net acres of shallow conventional potential in Ohio, Pennsylvania, West Virginia, and New York. In 2009, CNX Gas drilled and completed fourteen wells in the Marcellus Shale in southwestern Pennsylvania. Three wells were completed as vertical completions and the remaining eleven wells were drilled and completed as horizontal wells. All wells were turned into production as of December 31, 2009.

Shallow Oil and Gas

In 2009, CNX Gas drilled and completed six shallow conventional wells and drilled one shallow conventional well to total depth in south central Pennsylvania. Two additional shallow conventional wells were drilled and completed in eastern Ohio. Eight of the nine total wells are in production at December 31, 2009 while the remaining well is awaiting completion of gathering facilities for collection.

Others

Cardinal Shale

We control approximately 338,000 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 2,500-4000 feet. In 2009, we continued testing the New Albany Shale which will lead us to drilling two horizontal wells in early 2010. We also have identified shallow oil and gas in which we produce two additional wells.

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Illinois Basin CBM

We also control 515,000 net CBM acres in Illinois and Indiana, including 71,000 net CBM acres which contain most of our recoverable coal reserves in Illinois.

Other Acreage

We have the right to extract CBM on 139,000 net acres in the San Juan Basin, 20,000 net acres in the Powder River Basin, 41,000 net acres in eastern Ohio, and 51,000 net acres in central West Virginia. We also have the right to extract oil and gas on 12,000 net acres in the San Juan Basin, 10,000 net acres in the Powder River Basin, and 40,000 net acres in various other areas.

Summary of Properties as of December 31, 2009

	Central Appalachia	Northern Appalachia	Other	Total
Estimated Net Proved Reserves (billion cubic feet equivalent)	1,551	332	28	1,911
Percent Developed	56%	42%	100%	54%
Net Producing Wells (including gob wells)	3,363	492	71	3,926
Net Proved Developed CBM Acres	148,988	92,533		241,521
Net Proved Undeveloped CBM Acres	34,433	12,209		46,642
Net Unproved CBM Acres(1)	548,904	1,046,088	674,162	2,269,154
Total Net CBM Acres	732,325	1,150,830	674,162	2,557,317
Net Proved Developed Oil & Gas Acres	8,129	5,005	98	13,232
Net Proved Undeveloped Oil & Gas Acres	5,936	1,720		7,656
Net Unproved Oil & Gas Acres(1)	483,202	248,094	399,040	1,130,336
Total Net Oil & Gas Acres	497,267	254,819	399,138	1,151,224

(1) Includes areas leased to others or participation interests in third party wells, as well as small acreage in other areas.

Development Wells (Net)

During the years ended December 31, 2009, 2008 and 2007, we drilled 247, 534 and 370 net development wells, respectively. Gob wells and wells drilled by other operators that we participate in are excluded. There was one dry development well in 2009. There were no dry development wells in 2008 or 2007. As of December 31, 2009, six wells are still in process. The following table illustrates the wells drilled referenced above by geographic region:

	For the Year Ended December 31,		
	2009	2008	2007
Central Appalachia	202	321	294
Northern Appalachia	45	213	76
Total	247	534	370

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Exploratory Wells (Net)

During the year ended December 31, 2009, 2008 and 2007, we drilled in the aggregate 18, 56 and 9 net exploratory wells, respectively. As of December 31, 2009, ten wells are still in process. The following table illustrates the exploratory wells drilled referenced above by geographic region:

	As of December 31,								
	2009			2008			2007		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
Central Appalachia	6		4	8		18	3		
Northern Appalachia	5	1	2	6		20			
Other				1	3		1		5
Total	11	1	6	15	3	38	4		5

Summary of Other Operating Data

Production

The following table sets forth net sales volumes produced for the periods indicated. There was no production from equity affiliates for the years ended December 31, 2009 and 2008. The year ended December 31, 2007 included our portion of equity interests.

	For the Year Ended December 31,		
	2009	2008	2007
Total Produced (million cubic feet)	94,415	76,562	58,249

Average Sales Prices and Lifting Costs

The following table sets forth the average sales price and the average lifting cost (the year ended December 31, 2007 includes our portion of equity interests) for all of our gas production for the periods indicated, including intersegment transactions. Lifting cost is the cost of raising gas to the gathering system and does not include depreciation, depletion or amortization.

	For the Year Ended December 31,		
	2009	2008	2007
Average Gas Sales Price Before Effects of Financial Settlements (per thousand cubic feet)	$ 4.15	$ 8.99	$ 6.87
Average Effects of Financial Settlements (per thousand cubic feet)	$ 2.53	$	$ 0.33
Average Gas Sales Price Including Effects of Financial Settlements (per thousand cubic feet)	$ 6.68	$ 8.99	$ 7.20
Average Lifting Cost excluding ad valorem and severance taxes (per thousand cubic feet)	$ 0.48	$ 0.58	$ 0.39

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Productive Wells and Acreage

Most of our development wells and proved acreage are located in Central Appalachia. Some leases are beyond their primary term, but these leases are extended in accordance with their terms as long as certain drilling commitments are satisfied. The following table sets forth, at December 31, 2009, the number of CNX Gas producing wells, developed acreage and undeveloped acreage:

	Gross	Net(1)
Producing Wells (including gob wells)	5,240	3,926
Proved Developed Acreage	260,327	254,753
Proved Undeveloped Acreage	56,090	54,298
Unproven Acreage	3,957,174	3,399,490
Total Acreage	4,273,591	3,708,541

(1) Net acres do not include acreage attributable to the working interests of our principal joint venture partners and the portions of certain proved developed acreage attributable to property we have leased to third-party producers. 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.

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 entered 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 51.6 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2009 at an average price of $8.76 per thousand cubic feet. As of December 31, 2009, we expect these transactions will cover approximately 45.7 billion cubic feet of our estimated 2010 production at an average price of $7.88 per thousand cubic feet, 22.6 billion cubic feet of our estimated 2011 production at an average price of $6.84 and 15.1 billion cubic feet of our estimated 2012 production at an average price of $6.84.

We have purchased firm transportation capacity on various interstate pipelines to ensure gas production flows to market. As of December 31, 2009, we have secured firm transportation capacity to cover more than our 2010, 2011 and 2012 hedged production.

The hedging strategy and information regarding derivative instruments used are outlined in Management s Discussion and Analysis of Results of Operations and Financial Condition Qualitative and Quantitative Disclosures About Market Risk and in Note 23 to the Consolidated Financial Statements.

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,					
	2009		2008		2007	
	Consolidated Operations	Affiliates	Consolidated Operations	Affiliates	Consolidated Operations	Affiliates
Proved developed reserves	1,040,257		783,290		667,726	3,584
Proved undeveloped reserves	871,134		638,756		672,183	
Total proved developed and undeveloped reserves	1,911,391		1,422,046		1,339,909	3,584

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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) As of December 31,		
	2009	**2008**	**2007**
Future net cash flows	$ 2,391	$ 2,824	$ 3,609
Total PV-10 measure of pre-tax discounted future net cash flows(1)	$ 1,480	$ 2,004	$ 2,288
Total standardized measure of after tax discounted future net cash flows	$ 894	$ 1,218	$ 1,390

(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 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 to the most directly comparable GAAP measure after-tax discounted future net cash flows.

Reconciliation of PV-10 to Standardized Measure

	As of December 31, (Dollars in millions)		
	2009	**2008**	**2007**
Future cash inflows	$ 7,975	$ 8,857	$ 9,509
Future production costs	(3,123)	(3,526)	(3,005)
Future development costs (including abandonments)	(996)	(794)	(636)
Future net cash flows (pre-tax)	3,856	4,537	5,868
10% discount factor	(2,376)	(2,533)	(3,580)
PV-10 (Non-GAAP measure)	1,480	2,004	2,288
Undiscounted income taxes	(1,465)	(1,714)	(2,259)
10% discount factor	879	928	1,361
Discounted income taxes	(586)	(786)	(898)
Standardized GAAP measure	$ 894	$ 1,218	$ 1,390

Competition

We operate primarily in the eastern United States. We believe that the gas market is highly fragmented and not dominated by any single producer. We believe that several of our competitors have devoted far greater resources than we have to gas exploration and development. We believe that competition within our market is based primarily on gas commodity trading fundamentals and pipeline transportation availability to the diverse market opportunities.

Power Generation

Through a joint venture with Allegheny Energy Supply Company, LLC, an affiliate of one of our largest coal customers, CNX Gas owns a 50% interest in an 88-megawatt, gas-fired electric generating facility. This facility is used for meeting peak load demands for electricity. The facility is located in southwest Virginia and

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uses coalbed methane gas that we produce. Because it is a peaking power facility, it does not operate at all times of the year, but the facility does provide a potential sales outlet for CNX Gas of up to 22 million cubic feet per day.

Other

CONSOL Energy provides other services both to our own operations and to others. These include land services, industrial supply services, terminal services (including break bulk, general cargo and warehouse services), river and dock services, and coal waste disposal services.

Land Resources

CONSOL Energy is developing property assets previously used to support our coal operations or property assets currently not utilized. CONSOL Energy expects to increase the value of our property assets by:

- developing surface properties for commercial uses other than coal mining or gas development when the location of the property is suitable;
- deriving royalty income from coal, oil and gas reserves CONSOL Energy owns but does not intend to develop;
- deriving income from the sustainable harvesting of timber on land CONSOL Energy and CNX Gas owns; and
- deriving income from the rental of surface property for agricultural and non-agricultural uses.

CONSOL Energy s objective is to improve the return on these assets without detracting from our core businesses and without significant additional capital investment.

Industrial Supply Services

Fairmont Supply Company, a CONSOL Energy subsidiary, is a general-line distributor of mining and industrial supplies in the United States. Fairmont Supply has 28 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 supplies to CONSOL Energy s mining and gas operations. Approximately 44% of Fairmont Supply s sales in 2009 were made to CONSOL Energy and CNX Gas operations.

Fairmont Supply Company s 100% owned subsidiary, Piping and Equipment, is a specialty distributor of pipe, valve and fittings. Piping and Equipment has ten locations in Florida, Alabama, Louisiana and Texas. Fairmont Supply Company s other 100% owned subsidiary, North Penn Pipe & Supply, LLC has locations in Warren and Troy, Pennsylvania, and distributes oil and gas field products, primarily tubular goods to the Northern Appalachia basin.

Terminal Services

In 2009, approximately 6.4 million tons of coal were shipped through CONSOL Energy s subsidiary, CNX Marine Terminal Inc. s, exporting terminal in the Port of Baltimore. Approximately 45% 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 and CSX Transportation, Inc.

River and Dock Services

CONSOL Energy s river operations, located in Monessen, Pennsylvania, transports coal from our mines, coal from other mines and non-coal commodities from river loadout facilities 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, 2009, we operated 24 towboats, 5 harbor boats and more than 650 barges. In 2009, our river vessels transported a total of 17.3 million tons of coal and other commodities, including 6.1 million tons of coal produced by CONSOL Energy mines.

CONSOL Energy provides dock services for our mines as well 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.

Coal Waste Disposal Services

CONSOL Energy operates an ash disposal facility on a 61-acre site in northern West Virginia to handle ash residues for coal customers that are unable to dispose of ash on-site at their generating facilities. The ash disposal facility can process 200 tons of material per hour, and is expected to dispose of approximately 125 thousand tons of fly ash in the current contract year. CONSOL Energy has a long-term contract with a cogeneration facility to supply coal and take the residual fly ash and bottom ash. Bottom ash is disposed locally at the cogeneration facility for road construction and other purposes.

Employee and Labor Relations

At December 31, 2009, CONSOL Energy had 8,012 employees, approximately 34.5% of whom were represented by the United Mine Workers of America (UMWA). A five-year labor agreement commenced January 1, 2007. This agreement expires December 31, 2011 and provides for a 20% across-the-board wage increase over its duration. Wages increased $0.50 per hour in 2009, and will increase $0.50 per hour for 2010 through 2011. Other terms of the agreement require additional contributions to be made into the employee benefit funds. Full health-care benefits for active and retired members and their dependents continued with no increase in co-payments. Newly employed inexperienced employees represented by the UMWA, hired after January 1, 2007 will not be eligible to receive retiree health care benefits. In lieu of these benefits, these employees will receive a defined contribution benefit of $1 per each hour worked.

Laws and Regulations

The coal 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, employee health and safety, 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, surface subsidence from underground mining, water discharge effluent limits, water appropriation, legislatively mandated benefits for current and retired coal miners, 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, and management of electrical equipment containing polychlorinated biphenyls, or PCBs. 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, past or ongoing violations of federal and state mining laws by individuals or companies no longer affiliated with CONSOL Energy could provide a basis to revoke existing permits and to deny the issuance of additional permits. CONSOL Energy is, or may be, required to prepare and present to federal, state or local authorities data and/or analyses pertaining to the effect or impact that any proposed exploration for or production of coal or gas may have upon the environment, public and employee health and safety. All requirements imposed by such authorities may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. Accordingly, the permits we need for our mining and gas operations may not be issued, or, if issued, may not be issued in a timely fashion. Permits we need may involve requirements that may be changed 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.

While it is not possible to quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. 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 when necessary. Compliance with these laws has substantially increased the cost of coal mining and gas production for all domestic coal and gas producers. 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, violations during mining and gas operations occur from time to time. None of the violations to date, or the monetary penalties assessed have been material. CONSOL Energy made capital expenditures for environmental control facilities of approximately \$50.4 million, \$10.6 million and \$17.6 million in the years ended December 31, 2009, 2008 and 2007, respectively. The capital expenditures for environmental control facilities increased in 2009 primarily due to starting construction of a water processing system at Buchanan Mine. CONSOL Energy expects to have capital expenditures of \$39.0 million for 2010 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 resulting in the issuance of more citations and with new regulations the amount of fines 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 rescue 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 reconstruction of existing seals in worked-out areas of mines;
- the purchase of new fire resistant conveyor belting underground; and
- additional training and testing that creates the need to hire additional employees.

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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 Affordable Health Choices Act currently being debated in the U.S. legislature provides for significant changes to the current Federal Black Lung Program. The current proposed legislative language would:

- provide for an automatic survivor benefit to be paid upon the death of a miner with an awarded black lung claim without proving that death was due to coal workers pneumoconiosis; and
- establish a rebuttable presumption if a miner had 15 or more years of coal mine employment and they were totally disabled by a respiratory condition that;

1. the miner is totally disabled due to pneumoconiosis;

2. that the miners death was due to pneumoconiosis;

3. or that at the time of death the miner was totally disabled by pneumoconiosis; and

- be retroactive to claims filed or pending since 2005.

The proposed legislation could have a material impact on the cost of our Federal Black Lung Program. The impact of the proposed changes is dependent upon what is finally approved by the legislature.

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 Fund 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 unassigned beneficiaries (referred to as orphans) to the companies. 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 or later NBCWA, and who subsequently goes out of business.

The Act requires some of our 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 the Combined Fund and the 1992 Benefit Plan. In addition, the NBCWA of 2007 requires our signatory subsidiaries to make specified payments to the

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1993 Benefit Plan through 2011. 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 expanding 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, after a phase-in period, the orphan premium payments due under the 1992 Benefit Plan. The 1992 Benefit Plan has a phase-in period for the federal contributions. Federal contributions were 25% in 2008 and 50% in 2009. Federal contributions will be 75% in 2010 and 100% thereafter. In addition, federal contributions are also to be phased-in over these same periods with respect to 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, the 1993 Benefit Plan and certain Abandoned Mine Land 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 these plans 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) has 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 are in effect 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 7-year period. The Pension Act includes a funding target phase-in provision consisting of a 94% funding target in 2009, 96% in 2010 and 100% thereafter. 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 2009 plan year funding ratio was 113%. 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 Toxic Substances Control Act,
- the Endangered Species Act,
- the Comprehensive Environmental Response, Compensation and Liability Act,
- the Emergency Planning and Community Right to Know Act, and
- the Resource Conservation and Recovery Act

as administered and enforced by 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 ongoing compliance and permitting programs designed to ensure compliance with such environmental laws.

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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 as well as sites to which CONSOL Energy or our subsidiaries sent waste materials.

Surface Mining Control and Reclamation Act

The 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 Federal Office of Surface Mining Reclamation and Enforcement (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. The mining permit application process, whether state or federal, is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of cultural resources, soils, vegetation and wildlife, and assessment of surface and ground water hydrology, climatology and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that we will mine. We develop mine and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mine and reclamation plan incorporates the provisions of SMCRA, the state programs and the complementary environmental programs that impact coal mining. Detailed engineering plans are included for all surface facilities built as part of the mine, including roads, ponds, shafts and slopes, boreholes, portals, pipelines and power lines, excess spoil disposal areas and coal refuse disposal facilities. Also included in the permit application are documents defining corporate ownership and control, property ownership and agreements pertaining to coal, minerals, oil and gas, water rights, rights of way and surface land and documents required by the OSM Applicant Violator System. We also must list all public and privately-owned structures located within minimum defined distances near to or above our mines and mining facilities. Once a permit application is prepared and submitted to the regulatory agency, it goes through an administrative completeness review and a separate technical review. Public notice of the proposed permit application is given in a local newspaper followed by a public comment period before a permit can be issued. Some mining permits take over a year to prepare, depending on the size and complexity of the mine and can take six months to three years to be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance. The public has the right to comment on and otherwise participate in the permitting process, including through administrative appeals of permits and possibly further appeals in the courts. The mine operator must submit a bond or otherwise secure the performance of reclamation obligations, including, as deemed appropriate by the regulatory authority, a bond sufficient to cover the costs of long-term treatment of mine drainage discharges from closed facilities or ones from which a post-mining discharge is anticipated. The earliest a reclamation bond can be fully released is five years after reclamation has been completed, however, partial releases may be obtained as certain stages of reclamation are completed. All states impose on mine operators the responsibility for repairing or compensating for damage occurring on the surface as a result of mine subsidence, a possible consequence of longwall or other methods of underground mining, including an obligation to restore or replace domestic water supplies adversely affected by underground mining. All states also impose an obligation on surface mining operations to replace domestic, agricultural or industrial 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 per ton fee is $0.315 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 $0.28 per ton for surface mined coal and $0.12 per ton for underground mined coal.

Under SMCRA, responsibility for unabated violations of SMCRA and other specified environmental laws, unpaid civil penalties and unpaid reclamation fees of subsidiaries and affiliates can be imputed to the parents and related companies if deemed to be owned or controlled by such entities. Data describing such ownership links must be provided by CONSOL Energy to the regulatory authorities. Similar violations by independent contract mine operators can also be imputed to other companies which are deemed, according to the regulations, to have owned or controlled the contract mine operator. Sanctions against the owner or controller are quite severe and can include being blocked from receiving new permits and revocation of any permits that have been issued since the time of the violations or, in the case of civil penalties and reclamation fees, since the time such amounts became due.

In the Commonwealth of Pennsylvania, where CONSOL Energy operates four longwall mines, approximately $10.3 million and $8.3 million of expenses were incurred during the years ended December 31, 2009 and 2008, respectively, to mitigate and repair impacts on streams from subsidence. Interpretations of technical guidance documents related to impacts of longwall mining on Pennsylvania streams require additional analysis on stream flows and biological statistics. We have received violation notices for past longwall activities which resulted in lower stream flows and water pooling areas both of which we are in the process of remediating. We also are completing additional stream analysis in order to comply with these recent interpretations at current Pennsylvania mining operations. Future Pennsylvania Department of Environmental Protection enforcement actions 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 $23.9 million for the year ended December 31, 2010.

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 processing operations primarily through permitting and/or emissions control requirements. For example, regulations relating to fugitive dust and coal combustion emissions could restrict CONSOL Energy s ability to develop new mines or require CONSOL Energy to modify our operations. National Ambient Air Quality Standards (NAAQS) for particulate matter resulted in some areas of the country being classified as non-attainment for fine particulate matter. Because thermal dryers located at coal preparation plants burn coal and emit particulate matter, CONSOL Energy s mining operations are likely to be directly affected where the NAAQS are implemented by the states.

CONSOL Energy believes we have obtained all necessary permits under the Clean Air Act. These permits have various expiration dates through March 2015. CONSOL Energy monitors permits required by operations regularly and takes appropriate action to extend or obtain permits as needed.

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. 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. For example, the federal Clean Air Act places limits on sulfur dioxide, nitrogen dioxide, and mercury emissions from electric power plants.

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In October 1998, the EPA finalized a rule requiring a number of eastern U.S. states to make substantial reductions in nitrogen oxide emissions by June 1, 2004 (the NOX SIP call). Further sulfur dioxide and nitrogen oxide emission reductions were adopted by regulations called the Clean Air Interstate Rules (CAIR), which were promulgated by the EPA in 2005. In July and December 2008, the U.S. Court of Appeals for the District of Columbia remanded the CAIR regulations to EPA but did not vacate the regulations. The regulations were not vacated because many states were already implementing them and some coal fired electric generating facilities were being equipped with scrubbers in order to comply with the CAIR requirements. EPA s position is that the CAIR rules are in effect and the states must implement them. EPA intends to adopt replacement regulations, but there is no specific schedule in place. The installation of additional control measures to achieve these reductions makes it more costly to operate coal-fired power plants and could make coal a less attractive fuel. In order to meet the proposed new limits for sulfur dioxide emissions from electric power plants, many coal users need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), blend high sulfur coal with low sulfur coal or switch to low sulfur coal or other fuels. More strict emission limits mean few coals can be burned without the installation of supplemental environmental control technology in the form of scrubbers. Many of our customers are in the process of installing scrubbers in response to the CAIR emissions requirements. We estimate that by 2012, more than half of the installed, coal-fired power plant capacity east of the Mississippi will be scrubbed. The increase in scrubbed capacity allows customers to consider purchasing more of our higher sulfur coals.

In 2005, the EPA finalized the Clean Air Mercury Rule (CAMR) which imposed caps on mercury emissions from coal-fired electric generating units. The first phase of the emission caps would have taken effect in 2010. In February 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAMR. EPA has indicated that it will develop emission limits for mercury for coal fired electric generating facilities under Section 112 of the Clean Air Act, which requires EPA to impose maximum achievable control technology limits. In October 2008, New York and the New England states submitted a petition to EPA under the Clean Water Act requesting EPA to convene a conference to address contributions of airborne mercury emissions that upwind states are alleged to be making to downwind water quality. This petition appears to be aimed at coal fired power plants. Various states have promulgated or are considering more stringent emission limits on mercury emissions from coal-fired electric generating units. Regulation of mercury emissions from coal-fired electric generating units could impact the market for coal.

A regional haze program initiated by the EPA to protect and to improve visibility at and around national parks, national wilderness areas and international parks may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions. These requirements could limit the demand for coal in some locations.

The United States Department of Justice, on behalf of the EPA, has filed lawsuits against several investor-owned electric utilities and brought an administrative action against one government-owned utility for alleged violations of the Clean Air Act. These lawsuits could require the utilities to pay penalties, install pollution control equipment or undertake other emission reduction measures which could positively or negatively impact their demand for CONSOL Energy coal. One such suit was settled in October 2007, by the owner of sixteen coal fueled electric generating plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. Although the utility did not admit any violations of the Clean Air Act, it agreed to annual sulfur dioxide and nitrogen oxides emission limits for all of its plants and it agreed to install additional emission controls on two of its plants.

Also, numerous proposals have been made at the international, national, regional and state levels that are intended to limit or capture emissions of greenhouse gases, such as carbon dioxide, and several states have adopted measures intended to reduce greenhouse gas loading in the atmosphere. If comprehensive legislation focusing on greenhouse gas emissions is enacted by the United States or individual states, it may adversely affect the use of and demand for fossil fuels, particularly coal, as an energy source for electricity generation. The U.S. Congress is considering climate change legislation that proposes to restrict greenhouse gas (GHG) emissions. President Obama

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has pledged to implement an economy-wide cap-and-trade program to reduce GHG emissions 80 percent by 2050 and pledged that he would cause the United States to be a world leader on GHG reduction and re-engage with the United Nations Framework Convention on Climate Change to develop a global GHG program. In 2007, the U.S. Supreme Court held in Massachusetts v. Environmental Protection Agency (EPA), that the EPA had authority to regulate GHGs under the Clean Air Act and a number of states have filed lawsuits seeking to force the EPA to adopt GHG regulations. In December 2009, the EPA made a determination that GHGs cause or contribute to air pollution and may reasonably be anticipated to endanger public health or welfare, which findings are prerequisites to EPA regulating GHGs under the Clean Air Act. Moreover, several states have already adopted, and other states are considering the adoption of, legislation or regulations to reduce emissions of greenhouse gases. Such regulation would significantly increase the cost of generation of electricity at coal fired facilities and could make competing forms of electricity generation more competitive.

Clean Water Act

The federal Clean Water Act and corresponding state laws affect coal mining and gas operations by imposing restrictions on discharges into regulated 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: protection of impaired waters so designated by individual states through the use of new effluent limitations known as Total Maximum Daily Load (TMDL) limits; anti-degradation regulations which protect state designated high quality/exceptional use streams by restricting or prohibiting discharges which result in degradation; requirements to treat discharges from coal mining properties for non-traditional pollutants, such as chlorides, selenium and dissolved solids; and protecting streams, wetlands, other regulated water sources and associated riparian lands from surface mining and/or the surface impacts of underground mining. These requirements may cause CONSOL Energy to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

Permits for discharges of fill material into streams in connection with mining operations are issued by the Army Corps of Engineers (the COE). The COE is empowered to issue nationwide permits for specific categories of filing activity that are determined to have minimal environmental adverse effects in order to save the cost and time of issuing individual permits under Section 404 of the Clean Water Act. Individual permits are required for activities determined to have more significant impacts to waters of the United States. Nationwide Permit 21 authorizes the disposal of dredge-and-fill material from mining activities into the waters of the United States. Since 2003, environmental groups have pursued litigation primarily in West Virginia and Kentucky challenging the validity of Nationwide Permit 21 and various individual permits authorizing valley fills associated with surface coal mining operations (primarily mountain top removal operations). This litigation has resulted in delays in obtaining these permits and has increased permitting costs. The most recent major decision in this line of litigation is the opinion of the United States Court of Appeals for the Fourth Circuit in *Ohio Valley Environmental Council v. Aracoma Coal Company,* 556 F.3d 177 (2009) (*Aracoma)*, issued on February 13, 2009. *Aracoma* appeared to be a major victory for the coal industry because the Court rejected all of the substantive challenges to the Section 404 permits involved in the case primarily by deferring to the expertise of the COE in review of the permit applications. The effect of the *Aracoma* decision was quickly nullified by several EPA initiatives. First, in early 2009, the EPA began to comment on Section 404 permit applications pending before the COE raising many of the same issues decided in favor of the coal industry in *Aracoma.* Many of the EPA s comment letters were submitted long after the end of the EPA s comment period based on what the EPA contended was new information on the impacts of valley fills on stream water quality immediately downstream of valley fills. However, the comment letters addressed many issues beyond the new information on alleged water quality impacts, such as, minimization of the size and number of valley fills, cumulative impacts of the operation on the watershed, and the types and extent of mitigation. These comment letters practically resulted in a moratorium on the issuance of Section 404 permits for valley fills for coal surface mines. A second initiative of the EPA is enhanced review of any permit for a coal mining activity that requires both a SMCRA permit and a Section 404 permit in the states of Kentucky, Ohio, Pennsylvania, Tennessee, Virginia and West

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Virginia (designated as Appalachian surface coal mining). This initiative resulted in a joint Memorandum of Understanding (MOU) among the COE, the EPA and the Department of Interior (OSM). The enhanced review under the MOU has continued the delay in COE action on pending Section 404 permit applications. The EPA s third initiative is to take a more active role in its review of NPDES permit applications for coal mining operations; especially in West Virginia where the EPA has decided to review all such NPDES permit applications. All of these initiatives have resulted in delays in the review and issuance of permits for surface coal mining applications. We anticipate that it will take longer to obtain permits and the costs of obtaining permits and compliance with permit conditions will increase significantly. So far, CONSOL Energy subsidiaries have been able to continue operating their existing mines. Also, in 2009 one subsidiary was able to obtain a Section 404 permit for a new surface mine in southern West Virginia. However, the new permit contains EPA mandated environmental protection conditions. Additionally, on January 4, 2010, the EPA published a notice in the Federal Register seeking public comment on the EPA s enforcement and compliance priorities for fiscal years 2011 through 2013. The list of priorities includes energy/mining resource extraction (a new priority targeting mountain top removal mining).

A CONSOL Energy subsidiary is subject to a state administrative order in West Virginia that requires compliance in 2013 with effluent limits for chlorides for discharges from four active and two closed underground coal mines in northern West Virginia. Given the volumes of water involved and the options that are available to timely meet the effluent limits, it is likely that it will be necessary to construct one or more treatment facilities using advanced water treatment technologies. These requirements may cause CONSOL Energy to incur additional costs that could adversely affect our operating results, financial condition and cash flows.

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. 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 releases of 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.

RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In a 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion wastes generated at electric utility and independent power producing facilities, such as coal ash. In May 2000, the EPA concluded that coal combustion wastes do not warrant regulation as hazardous under RCRA resulting in coal combustion wastes remaining exempt from hazardous waste regulation. However, the EPA determined that national non-hazardous waste regulations under RCRA are needed for coal combustion wastes disposed in surface impoundments and landfills and used as mine-fill, and the Office of Surface Mining is currently developing these regulations. The agency also concluded that beneficial uses of these wastes, other than for mine-filling, pose no significant risk and no additional national regulations are needed. Most state hazardous waste laws also exempt coal combustion waste, and instead treat it as either a solid waste or a special waste. In response to the Tennessee Valley Authority coal ash spill in December 2008, the EPA initiated a fast-track regulatory process in which it is considering three possible regulatory scenarios for coal combustion wastes: regulation as a non-hazardous waste under Subtitle D of RCRA, regulation as a hazardous waste under Subtitle C, or a hybrid Subtitle C/D approach. Industry and state regulatory agencies are trying to convince the EPA that the states are adequately regulating handling and disposal of coal combustion wastes. The loss of the hazardous waste exemption for coal combustion waste, or the adoption of new regulations for disposing of coal combustion waste which impose significant additional costs, could adversely affect the demand for coal for electricity generation.

Federal Coal Leasing Amendments Act

Mining operations on federal lands in the western United States are affected by regulations of the United States Department of the Interior. The Federal Coal Leasing Amendments Act of 1976 amended the Mineral Lands Leasing Act of 1920 which authorized the leasing of federal coal lands for coal mining. The Federal Coal Leasing Amendments Act increased the royalties payable to the United States Government for federal coal leases and required diligent development and continuous operations of leased reserves within a specified period of time. Subtitle D of the Energy Policy Act of 2005 (Pub. L. 109-58) contained the Coal Leasing Amendments Act of 2005, which includes provisions designed to facilitate efficient and economic development of federal coal leases. The United States Department of the Interior has stated that it intends to promulgate new regulations and implement these 2005 amendments. Regulations adopted by the United States Department of the Interior to implement such legislation could affect coal mining by CONSOL Energy from federal coal leases for operations developed that would incorporate such leases. Currently, CONSOL Energy s only active operation with federal coal leases is the Emery Mine.

Endangered Species Act

The Federal Endangered Species Act (ESA) and similar state laws protect species threatened with extinction. Protection of endangered species may affect our ability to obtain permits, may delay issuance of mining permits, or may cause us to modify mining 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 from our properties.

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. 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. 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.

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. 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 material or 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 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 drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, 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. Our operations are also subject to various conservation laws and regulations. These include regulations that affect the size of drilling and spacing units or proration units, the density of wells which may be drilled and the unitization or pooling of gas properties. In addition, state conservation laws establish maximum rates of production from gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. 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

The majority of our drilling operations are conducted on properties related to our coal holdings.

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CONSOL Energy s past practice has been to acquire ownership or leasehold rights to our coal properties prior to conducting our coal mining operations. Given CONSOL Energy s long history as a coal producer we believe we have a well-developed ownership position relating to our coal holdings. Although CONSOL Energy generally attempts to obtain ownership or leasehold rights to CBM and/or conventional gas related to our coal holdings, our ownership position relating to these property estates is less developed. As is customary in the coal and gas industry, a summary review of the title to coal, CBM and other gas rights is made on properties at the time of the acquisition of the other rights in the properties. Prior to the commencement of gas drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties; we are typically responsible for curing any title defects. We generally will not commence our drilling operations on a property until we have cured any material title defects on such property. We completed title work on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the gas industry.

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.

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.

Virginia

The vast majority of CBM we produce, as well as our proved reserves, are in Virginia. The Virginia Supreme Court has stated that the grant of coal rights only does not include rights to CBM absent an express grant of CBM, natural gases, or minerals in general. The situation may be different if there is any expression in the severance deed indicating more than mere coal is conveyed. Virginia courts have also found that the owner of the CBM did not have the right to fracture the coal in order to retrieve the CBM and that the coal operator had 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 the vast majority of our producing properties.

In addition, Virginia has established the Virginia Gas and Oil Board and a procedure for 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. The general practice is to force pool both the coal owner and the gas owner. In those instances, any royalties otherwise payable 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.

West Virginia

The West Virginia Supreme Court has held that in 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. As of December 31, 2009, the West Virginia courts have not clarified who owns CBM in West Virginia. Therefore, the ownership of CBM is an open question in West Virginia.

West Virginia has enacted a law, 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 pooling law. 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.

We anticipate in future years to more actively explore for and develop Northern Appalachian CBM in West Virginia. As indicated, we may need or desire to acquire additional rights from other holders of real estate interests, including acquiring rights from other real estate interest holders if the law at that time continues to lack clarity on ownership rights to CBM in West Virginia. As we explore and develop this other acreage where we have coal rights, we expect in accordance with our existing procedures to have a title examination performed of the rights to CBM. If we believe we need to obtain additional rights from the holders of other real estate interests, we have developed a methodology as part of deciding the feasibility of developing a particular tract to evaluate the ability to locate and negotiate a royalty arrangement with those other holders or use pooling provisions under the West Virginia Act.

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).

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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.

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

As widely reported, economic conditions in the United States and globally have deteriorated and the extent and timing of a recovery, especially in the United States and Europe, is uncertain. Financial markets in the United States, Europe and Asia have also experienced a period of unprecedented turmoil and upheaval 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. Unemployment has risen while business and consumer confidence have declined and there are fears of a prolonged recession in the United States and Europe. Although we cannot predict the impacts, continued weakness in the United States or global economies, in any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

- the demand for natural gas in the United States has declined and may remain at low levels or further decline if economic conditions remain weak and continue to negatively impact the revenues, margins and profitability of our natural gas business;

- the demand for electricity in the United States and for steel globally has declined and may remain at low levels or further decline if economic conditions remain weak and continue to negatively impact the revenues, margins and profitability of our steam and metallurgical coal businesses;

- 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 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.

A significant or extended decline in the prices CONSOL Energy receives for our coal and gas could adversely affect our operating results and cash flows.

Our financial results are significantly affected by the prices we receive for our coal and gas. Extended or substantial price declines for coal would adversely affect our operating results for future periods and our ability to generate cash flows necessary to improve productivity and expand operations. Prices of coal may fluctuate due to factors beyond our control such as overall domestic and global economic conditions; the consumption pattern of industrial consumers, electricity generators and residential users; technological advances affecting energy consumption; domestic and foreign government regulations; price and availability of alternative fuels; price of foreign imports and weather conditions. Any adverse change in these factors could result in weaker demand and possibly lower prices for our production, which would reduce our revenues.

Gas prices are closely linked to consumption patterns of the electric generation industry and certain industrial and residential patterns where gas is the principal fuel. Natural gas prices are very volatile, and even relatively modest drops in prices can significantly affect our financial results and impede growth. Changes in natural gas prices have a significant impact on the value of our reserves and on our cash flow. In the past we have used hedging transactions to reduce our exposure to market price volatility when we deemed it appropriate. If we

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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 and oil prices than our competitors who engage in hedging arrangements to a greater extent than we do. 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 and foreign supply of natural gas; the price of foreign imports; overall domestic and global economic conditions; the consumption pattern of industrial consumers, electricity generators and residential users; weather conditions; technological advances affecting energy consumption; domestic and foreign governmental regulations; proximity and capacity of gas pipelines and other transportation facilities; and the price and availability of alternative fuels. Many of these factors may be beyond our control. Lower natural gas prices may not only decrease our revenues on a per unit basis, but may also limit our access to capital. A significant decrease in price levels for an extended period would negatively affect us in several ways including our cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves or increase production; and 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 a material adverse effect on our results of operations in the period taken.

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

During the year ended December 31, 2009, approximately 91% 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 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, 2009, we derived over 25% of our total revenues from sales to our four largest coal customers. At December 31, 2009, we had approximately 16 coal supply agreements with these customers that expire at various times from 2010 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 four 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 materially.

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 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 $165 million accounts receivable securitization program and our business could be adversely affected. In addition, if a customer refuses 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.

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.

Competition within the coal and gas industries may adversely affect our ability to sell our products. A loss of our competitive position because of overcapacity in these industries could adversely affect pricing 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 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 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 for 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 and we may compete with foreign companies for domestic sales, many of whom 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. For example, one of our competitive strengths is being a low-cost producer of gas. If our competitors can produce gas at a lower cost than us, it would effectively eliminate our competitive strength in that area. In addition, larger companies may be able to pay more to acquire new gas properties for future exploration, limiting our ability to replace gas we produce or to grow our production. Our ability to acquire additional properties and to discover new 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, 2009, we had 8,012 employees. Approximately 35% of these employees are represented by unions. Union operations generated 46% of our U.S. coal production during the year ended December 31, 2009. Relations with our employees and, where applicable, organized labor is important to our success. If we do not maintain satisfactory labor relations with our organized and non-union employees, we may incur strikes, other work stoppages or have reduced productivity. Our labor costs may increase relative to other coal companies which could adversely affect our ability to compete with other coal companies and our results of operations.

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The characteristics of coal may make it difficult for coal users to comply with various environmental standards. These standards are continually under review by international, federal and state agencies, related to coal combustion. As a result, coal users may switch to other alternative fuel or alternative energy sources, which would affect the volume of CONSOL Energy s coal sales.

Coal contains impurities, including sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air when coal is burned. Stricter environmental regulations of emissions from coal-fired electric generating plants could increase the costs of using coal thereby reducing demand for coal as a fuel source, the volume of our coal sales and price. Stricter regulations could make coal a less attractive fuel alternative in the planning and building of utility power plants in the future.

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 power generators switch to alternative fuel could materially affect us if we cannot offset the cost of sulfur removal by lowering the delivered costs of our higher sulfur coals on an energy equivalent basis.

Proposed reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, particulate matter or greenhouse gases 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. The Environmental Protection Agency continues to require reduction of nitrogen oxide emissions in a number of eastern states and the District of Columbia and will require reduction of particulate matter emissions over the next several years for areas that do not meet air quality standards for fine particulates. In addition, Congress and several states may consider legislation to further control air emissions of multiple pollutants from electric generating facilities and other large emitters. Any new or proposed reductions will make it more costly to operate coal-fired plants and could make coal a less attractive fuel alternative to the planning and building of utility power plants in the future. In addition, utilities may favor building new power plants fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain as natural gas is seen as having a lower environmental impact than coal-fueled generators. Apart from alternative fuel sources, 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 reduction in the amount of coal consumed by domestic

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electric power generators as a result of new or proposed requirements or a switch to alternative fuels or renewable energy sources could reduce the price of coal that we mine and sell, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

CONSOL Energy may not be able to produce sufficient amounts of coal to fulfill our customers requirements, which could harm our relationships with customers and could cause our inability to satisfy our contractual demands.

CONSOL Energy may not be able to produce sufficient amounts of coal to meet customer demand, including amounts that we are required to deliver under long-term contracts. CONSOL Energy s inability to satisfy contractual obligations could result in our customers initiating claims against us.

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.

Coal mining is subject to conditions or events beyond CONSOL Energy s control, which could cause our financial results to deteriorate.

CONSOL Energy s coal mining operations are predominantly underground mines. These mines are subject to conditions or events beyond CONSOL Energy s control that could disrupt operations and affect production and the cost of mining at particular mines for varying lengths of time. These conditions or events may have a significant impact on our operating results. Conditions or events have included:

- 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 and other accidents; and
- weather conditions.

A decrease in the availability or increase in the costs of key services, capital equipment or commodities such as steel, liquid fuels and rubber products could impact our cost of production and decrease our anticipated profitability.

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

For mining and drilling operations, CONSOL Energy must obtain, maintain, and renew governmental permits and approvals which can be a costly and time consuming process and can result in restrictions on our operations.

Most 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 of the laws that regulate mining. The pace with which 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 mining on various grounds. The most recent challenges have focused on the adequacy of the 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. 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. However, since that reversal, the U.S. Environmental Protection Agency (EPA) began to more critically review valley fill permits and has been recommending that a number of permits be denied because of alleged concerns by EPA of potential impacts to water quality in streams below valley fills, with cumulative impacts of mining on watersheds and with adequacy of mitigation EPA s objections and an enhanced review process that is being implemented under a federal multi-agency memorandum of understanding have effectively held up the issuance of permits for all types of mining operations that require valley fill permits, including surface facilities for underground mines, without any indication as to when normal permitting will resume. CONSOL Energy s surface and underground operations have been impacted to a limited extent to date, but future permits will likely be delayed by the EPA s current position, which will likely adversely impact our surface operations. In addition, over the past few years, 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. New safety laws and regulations have impacted productivity at underground mines, although the company has not yet been able to ascertain the exact amount of the impact.

Proposals to regulate greenhouse gas emissions could impact the market for our fossil fuels, increase our costs and reduce the value of our coal and gas assets.

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 that is currently emitted into the atmosphere by coal and gas end users, such as coal-fired electric generation power 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. Further regulation of GHGs could occur in the United States pursuant to legislation, treaty obligations, regulation under the Clean Air Act, or states enacting new laws and regulations. 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) expires in 2012 and negotiations are underway for a new protocol. In 2007, the U.S. Supreme Court upheld in Massachusetts v. the Environmental Protection Agency (EPA), that the EPA had authority to regulate GHG s under the Clean Air Act and a number of states have filed lawsuits seeking to force the EPA to adopt GHG regulations. President Obama has pledged to implement an economy-wide cap-and-trade program to reduce GHG emissions 80 percent by 2050. He also pledged the United States to be a world leader on GHG reduction and re-engage with the United Nations Framework Convention on Climate Change to develop a global GHG program. 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 utility power plants which may make it more difficult for utilities to obtain financing for coal-fired plants. If comprehensive laws focusing on GHGs emission reductions were to be enacted by the United States, individual states, in other countries where we sell coal, or if utilities were to have difficulty obtaining financing in connection with coal-fired plants, it may adversely affect the use of and demand for fossil fuels, particularly coal, which could have a material adverse effect on our results of operations, cash flows and financial condition.

In July 2008, the EPA published an Advance Notice of Proposed Rulemaking (ANPR) seeking comments and discussion of the complex issues associated with the possible regulation of GHGs under the Clean Air Act.

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The deadline for comments on the ANPR was November 28, 2008. The EPA sought comments and discussion on: (i) advantages and disadvantages of regulating GHGs under various provisions of the Clean Air Act; (ii) how a decision to regulate GHGs under one provision of the Clean Air Act would lead to regulation under other provisions; (iii) issues relevant to legislation to regulate greenhouse gases and the potential overlap of the Clean Air Act and such future legislation; and (iv) scientific information relevant to, and the issues raised by, an analysis as to whether greenhouse gas emissions from automobiles may reasonably be anticipated to endanger public health or welfare. In December 2009, the EPA made a determination that GHGs cause or contribute to air pollution and may reasonably be anticipated to endanger public health or welfare, which findings are prerequisites to the EPA regulating GHGs under the Clean Air Act.

Coalbed methane must be expelled from our underground coal mines for mining safety reasons. Coalbed methane enhances the GHG effect to a greater degree 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 curtail coal production, pay higher taxes, or incur costs to purchase credits that permit us to continue operations as they now exist at our underground coal mines. The amount of coalbed methane we capture is recorded, on a voluntarily basis, with the U.S Department of Energy. We have recorded the amounts we have captured since the early 1990 s and our subsidiary, CNX Gas, has registered as an offset provider of credits with the Chicago Climate Exchange. If regulation of GHGs does not give us credit for capturing methane that would otherwise be released into the atmosphere at our coal mines, any value associated with our historical or future credits would be reduced or eliminated.

Existing and future government laws, regulations and other legal requirements relating to protection of the environment, health and safety matters and others that govern our business increase our costs of doing business for both coal and gas, and may restrict our 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 and health and safety matters, including 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, 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, control 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 effect on our costs of operations and competitive position. In addition, we could incur substantial costs as a result of violations under environmental and health and safety 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 and health and safety matters could further affect our costs of operations and competitive position.

For example, the federal Clean Water Act and corresponding state laws affect coal mining and gas operations by imposing restrictions on discharges into regulated 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 (including those relating to protection of impaired waters so designated by individual states through the use of new effluent limitations known as Total Maximum Daily Load (TMDL) limits; anti-degradation regulations which protect state designated high quality/exceptional use streams by restricting or prohibiting discharges which result in degradation; and requirements to treat discharges from coal mining properties for non-traditional pollutants requiring expensive treatment technologies, such as total dissolved solids, chlorides and selenium; and protecting streams, wetlands, other regulated water sources and associated riparian lands from the surface impacts of underground mining) may cause CONSOL Energy to incur significant additional costs that could adversely affect our operating results, financial condition and

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cash flows or may prevent us from being able to mine portions of our reserves. The Clean Water Act is being used by opponents of mountain top removal mining as a means to challenge permits. Also, beginning in early 2009, EPA has relied upon the Clean Water Act to become more actively involved in the permitting of mountain top removal mining operations and other coal mining operations requiring permits to place fill in streams. In addition, CONSOL Energy incurs and will continue to incur significant 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.

Additionally, the gas industry is subject to extensive legislation and regulation, which is under constant review for amendment or expansion. Any changes may affect, among other things, the pricing or marketing of gas production. 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. If we fail to comply with statutes and regulations, we may be subject to substantial penalties, which would decrease our profitability.

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.

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.

CONSOL Energy has reclamation, mine closure 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 and gas well drilling. 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 $533 million at December 31, 2009. 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.

CONSOL Energy faces uncertainties in estimating our economically recoverable coal 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 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 cost of materials.

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 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. As a result, our estimates may not accurately reflect our actual reserves.

Fairmont Supply Company, a subsidiary of CONSOL Energy, is a co-defendant 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 22,500 asbestos claims in state courts in Pennsylvania, Ohio, West Virginia, Maryland, Mississippi, New Jersey 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. For the year ended December 31, 2009, payments by Fairmont with respect to asbestos cases have not been material**.** Our current estimates related to these asbestos claims, individually and in the aggregate, are immaterial to the financial position, results of operations and cash flows of CONSOL Energy. 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 and its subsidiaries are subject to various legal proceedings, which may have a material effect on our business.

We are party to a number of legal proceedings incident to normal business activities. There is the potential that an individual matter or the aggregation of many matters could have an adverse effect on our cash flows,

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results of operations or financial position. See Note 24 in the Notes to the Audited Consolidated Financial Statements in Item 8 of the Form 10-K for further discussion.

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

The federal government has been reviewing the income tax regulations relating to the coal industry regarding percentage depletion benefits. If the percentage depletion tax benefit was reduced or eliminated, CONSOL Energy s financial position could be materially impacted.

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, 2009, the current and non-current portions of these obligations included:

postretirement medical and life insurance ($2.8 billion);

coal workers black lung benefits ($194.6 million);

salaried retirement benefits ($192.0 million); and

workers compensation ($179.3 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 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 a multi-employer pension plan, we have exposure under that plan that extends beyond what our obligation would be with respect to our employees.

Certain of our subsidiaries are obligated to contribute to a multi-employer defined benefit pension plan for United Mine Workers of America (UMWA) retirees. In the event of a partial or complete withdrawal by us from such pension plan, we 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 limited information available from the plan's administrators, which we cannot independently validate, we believe that our portion of the contingent liability represented by the pension plan's unfunded vested benefits, in the case of our withdrawal from the pension plan or the termination of the pension plan, could be material to our financial position and results of operations. In the event that any other contributing employer withdraws from such pension plan 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 a proportionate share of the pension plan s unfunded vested benefits at the time of our withdrawal from the pension plan or its termination.

The minimum funding level requirements of the Pension Protection Act of 2006 (Pension Act) applicable to single employer and multi-employer defined benefit pension plans, coupled with significant investment asset losses suffered by such pension plans during the recent decline in equity markets and the current volatile economic environment, have exposed CONSOL Energy to having to make additional cash contributions to fund the pension benefit plans which we sponsor and the multi-employer pension benefit plans in which we participate.

CONSOL Energy sponsors a defined benefit retirement plan that covers substantially all of our employees not participating in multi-employer pension plans. For this pension plan, the Pension Act requires a funding target of 100% of the present value of accrued benefits. The Pension Act includes a funding target phase-in provision that establishes a funding target of 96% in 2010 and 100% thereafter for our defined benefit pension plan. Any such plan with a funded ratio of less than 80%, or less than 70% using special assumptions, will be

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deemed to be at risk and will be subject to additional funding requirements under the Pension Act. The volatile economic environment and the deterioration in the equity markets have caused investment income and the value of investment assets held in our pension trust to decline and lose value. As a result, CONSOL Energy may be required to increase the amount of cash contributions it makes into the pension trust in order to meet the funding level requirements of the Pension Act.

Certain subsidiaries of CONSOL Energy also participate in a defined benefit multi-employer pension plan negotiated with the UMWA and contained in the National Bituminous Coal Wage Agreement (the NBCWA). The NBCWA currently calls for contribution amounts to be paid into the multi-employer 1974 Pension Trust based principally on hours worked by UMWA-represented employees. The current contribution rates called for by the NBCWA are: $4.25 per hour worked in 2009, $5.00 per hour worked in 2010, and $5.50 per hour worked in 2011. These multi-employer pension plan contributions are expensed as incurred. The Pension Act requires a minimum funding ratio of 80% be maintained for this multi-employer pension plan. If the plan was determined to have a funded ratio of less than 80% it will be deemed to be endangered or "seriously endangered", and if less than 65%, it will be deemed to be in critical status, and will in either case be subject to additional funding requirements. Under the Pension Act, the multi-employer plan's actuary must certify the plan's funded status for each plan year. Based on an estimated funded percentage of 91.4%, a certification was provided by the multi-employer plan actuary, stating that the 1974 Pension Trust was in neither endangered nor critical status for the plan year beginning July 1, 2008. However, the volatile economic environment and the rapid deterioration in the equity markets caused investment income and the value of investment assets held in the 1974 Pension Trust to decline and lose value.

In late 2008, the Worker, Retiree and Employer Recovery Act of 2008 ("WRERA") was enacted. Under WRERA, a plan is permitted temporarily to avoid applying the Pension Act's requirements for improving its financial status by giving a plan the option to elect to retain its prior year zone status and to freeze the plan's zone status at the level determined for 2008. WRERA also required that the plan's actuary certify the plan's actual zone status for 2009. On September 28, 2009, based on an estimated funded percentage of 74%, the 1974 Pension Trust's actuary provided the Pension Act zone certification for 2009, certifying that the 1974 Pension Trust is seriously endangered for the plan year beginning July 1, 2009. Thereafter, pursuant to WRERA, the 1974 Pension Trust elected to retain its 2008 funded status of neither "endangered" nor critical for the plan year beginning July 1, 2009. If the freeze election had not been made, the 1974 Pension Trust's zone status for 2009 as certified by its actuary would have been "seriously endangered" and the 1974 Pension Trust would have been required to develop a funding improvement plan.

The freeze election only applies for the current plan year of 2009. If the 1974 Pension Trust is certified to be in endangered, seriously endangered or critical status for the plan year beginning July 1, 2010, steps will have to be taken under the Pension Act to improve its funded status. Such a determination would require certain subsidiaries of CONSOL Energy to make additional contributions pursuant to a funding improvement plan implemented in accordance with the Pension Act and, therefore, could have a material impact on our operating results.

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 materially 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

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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 material reduction in operating results.

Various federal or state laws and regulations require CONSOL Energy to obtain surety bonds or to provide other assurance of payment for certain of our long-term liabilities including mine closure or reclamation costs, workers compensation, coal workers black lung and other postemployment benefits.

Federal and state laws and regulations require us to provide surety bonds or provide other assurances to secure payment of certain long-term obligations including mine closure or reclamation costs, water treatment costs, federal and state workers compensation costs and other miscellaneous obligations. The requirements and amounts of security are not fixed and can vary from year to year. For certain requirements, there have been periods in the past when it has been difficult for us to secure new surety bonds or renew such bonds without posting collateral. CONSOL Energy has satisfied our obligations under these statutes and regulations by providing letters of credit or other assurances of payment. The issuance of letters of credit under our bank credit facility reduces amounts that we can borrow under our bank credit facility for other purposes.

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.

We have completed several acquisitions and mine and gas expansions in the past. We 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, our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Mine expansion, gas operation expansion and acquisition transactions 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;
- Problems that could arise from the integration of the acquired business; and
- Unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion or the acquisition opportunity.

CONSOL Energy s rights plan may have anti-takeover effects that could prevent a change of control.

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 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.

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We face uncertainties in estimating proved recoverable gas reserves, and inaccuracies in our estimates could result in lower than expected reserve quantities and a lower present value of our reserves.

Natural gas reserves requires subjective estimates of underground accumulations of natural gas and assumptions concerning future natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved 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 future 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 reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of 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 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;
- assumptions governing future prices;
- the amount and timing of actual production;
- 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 reserves as of December 31, 2009 would decrease from $1.5 billion to $1.4 billion. The standardized Generally Accepted Accounting Principle measure associated with this decline of $0.10 per thousand cubic feet, would be approximately $0.8 billion.

Unless we replace our natural gas reserves, our 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, 2009, 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.

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Our exploration and development activities may not be commercially successful.

The exploration for and production of gas involves numerous risks. The cost of drilling, completing and operating wells for coal bed methane (CBM) or other gas is often uncertain, and a number of factors can delay or prevent drilling operations or production, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;
- pipeline ruptures; and
- unavailability or high cost of drilling rigs, other field services and equipment.

Our future drilling activities may not be successful, and our drilling success rates could decline. Unsuccessful drilling activities could result in higher costs without any corresponding revenues.

Our focus on new development projects in our operating areas and other unexplored areas increases the risks inherent in our gas and oil activities.

We have little or no proved reserves in certain areas in Pennsylvania, Kentucky and Tennessee. These exploration, drilling and production activities will be subject to many risks, including the risk that CBM or other natural gas is not present in sufficient quantities in the coal seam or target strata, or that sufficient permeability does not exist for the gas to be produced economically. We have invested in property, and will continue to invest in property, including undeveloped leasehold acreage, that we believe will result in projects that will add value over time. Drilling for CBM, other natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. We cannot be certain that the wells we drill in these new areas will be productive or that we will recover all or any portion of our investments.

Our business depends on transportation facilities owned by others. Disruption of, capacity constraints in, or proximity to pipeline systems could limit sales of our gas.

We transport our gas to market by utilizing pipelines owned by others. If pipelines do not exist near our producing wells, if pipeline capacity is limited or if pipeline capacity is unexpectedly disrupted, our gas sales could be limited, reducing our profitability. If we cannot access pipeline transportation, 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 are reduced because of transportation constraints, our revenues will be reduced, and our unit costs will also increase. If we cannot obtain transportation capacity and we do not have the ability to store gas, we may have to reduce production. If pipeline quality tariffs change, we might be required to install additional processing equipment which could increase our costs. The pipeline could curtail our flows until the gas delivered to their pipeline is in compliance.

Increased industry activity may create shortages of field services, equipment and personnel, which may increase our costs and may limit our ability to drill and produce from our natural gas properties.

The demand for well service providers, related equipment, and qualified and experienced field personnel to drill wells and conduct field operations, including geologists, geophysicists, engineers and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices,

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causing periodic shortages. These shortages may lead to escalating prices, the possibility of poor services, inefficient drilling operations, and personnel injuries. Such pressures will likely increase the actual cost of services, extend the time to secure such services and add costs for damages due to accidents sustained from the over use of equipment and inexperienced personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling equipment, crews and associated supplies, equipment and services. 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 material increases in the cost of, drilling equipment, crews and associated supplies, equipment and services in the future. Any such delays and price increases could adversely affect our ability to pursue our drilling program and our results of operations.

We may incur additional costs and delays to produce gas because we have to acquire additional property rights to perfect our title to the gas estate.

Some of the gas rights we believe we control are in areas where we have not yet done any exploratory or production drilling. Most of these properties were acquired primarily for the coal rights, and, in many cases were acquired years ago. While chain of title work for the coal estate was generally fully developed, in many cases, the gas estate title work is less robust. Our practice is to perform a thorough title examination of the gas estate before we commence drilling activities and to acquire any additional rights needed to perfect our ownership of the gas estate for development and production purposes. We may incur substantial costs to acquire these additional property rights and the acquisition of the necessary rights may not be feasible in some cases. Our inability to obtain these rights may adversely impact our ability to develop those properties. Some states permit us to produce the 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 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.

Our shale gas drilling and production operations require adequate sources of water to facilitate the fracturing process and the disposal of that water when it flows back to the well-bore, and our CBM gas drilling and production operations require the removal and disposal of water from the coal seams, from which we produce gas. If we are unable to dispose of the water we use or remove from the strata at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially and in commercial quantities could be impaired.

New environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse affect on our operations and financial performance.

Coal seams, frequently contain water that must be removed in order for the gas to detach from the coal and flow to the wellbore. Further, we must remove the water that we use to fracture our shale gas wells when it flows back to the well-bore. Our ability to remove and dispose of water will affect our production and the cost of water treatment and disposal may affect our profitability. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing or disposal of waste, including, produced water, drilling fluids and other wastes associated with the exploration, development and production of natural gas.

Coalbed methane and other gas that we produce often contains impurities that must be removed, and the gas must be processed before it can be sold, which can adversely affect our operations and financial performance.

A substantial amount of our gas needs to be processed in order to make it saleable to our intended customers. At times, the cost of processing this gas relative to the quantity of gas produced from a particular well, or group of wells, may outweigh the economic benefit of selling that gas. Our profitability may decrease due to the reduced production and sale of gas.

Enactment of a severance tax in several states where we have operations, including Pennsylvania, on natural gas could adversely impact our results of existing operations and the economic viability of exploiting new gas drilling and production opportunities in those states.

As a result of a funding gap in the Pennsylvania state budget due to significant declines in anticipated tax revenues, the Pennsylvania governor has proposed to its legislature the adoption of a wellhead or severance tax on the production of natural gas in Pennsylvania. The amount of the proposed tax is 5 percent of the value of the natural gas at wellhead plus 4.7 cents per thousand cubic feet of natural gas severed. In Pennsylvania we have rights in significant acreage for coalbed methane and other natural gas extraction on which we have drilled and expect to continue to drill producing wells. In 2009, 17% or 18.4 billion cubic feet, of our production was from Pennsylvania. In addition, a significant amount of our Marcellus shale play acreage is in Pennsylvania. We cannot predict whether Pennsylvania (or any other states) will adopt any such tax, nor if adopted the rate of tax. If states adopt such taxes, it could adversely impact our results of existing operations and the economic viability of exploiting new gas drilling and production opportunities.

Currently the majority of our producing properties are located in three counties in southwestern Virginia, making us vulnerable to risks associated with having our production concentrated in one area.

The vast majority of our producing properties are geographically concentrated in three counties in Virginia. As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailment of production, natural disasters or interruption of transportation of natural gas produced from the wells in this basin or other events which impact this area.

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, 2009, we had hedges on approximately 45.7 billion cubic feet of our 2010 natural gas production, 22.6 billion cubic feet of our 2011 natural gas production and 15.1 billion cubic feet of our 2012 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.

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.

Item 1B. ***Unresolved Staff Comments.***

None.

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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 eighteenth paragraphs of Note 24 of the Notes to the Audited Consolidated Financial Statements included as Item 8 in Part II of this Form 10-K are incorporated herein by reference.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

None.

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PART II

Item 5. ***Market for Registrant s Common Equity and Related Stockholder Matters and Issuer Purchases of Equity Securities.***
Common Stock Market Prices and Dividends

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, 2009:			
Quarter Ended March 31, 2009	$ 37.66	$ 22.47	$ 0.10
Quarter Ended June 30, 2009	$ 44.13	$ 24.01	$ 0.10
Quarter Ended September 30, 2009	$ 49.84	$ 28.60	$ 0.10
Quarter Ended December 31, 2009	$ 53.50	$ 42.18	$ 0.10
Year Period Ended December 31, 2008:			
Quarter Ended March 31, 2008	$ 84.18	$ 53.63	$ 0.10
Quarter Ended June 30, 2008	$ 119.10	$ 67.33	$ 0.10
Quarter Ended September 30, 2008	$ 112.23	$ 36.25	$ 0.10
Quarter Ended December 31, 2008	$ 44.95	$ 18.50	$ 0.10

As of December 31, 2009, there were 186 holders of record of our common stock. The computation of the approximate number of shareholders is based upon a broker search.

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, Alliance Resource Partners, Alpha Natural Resources, Inc., Anadarko Petroleum Corp., Apache Corp., Arch Coal, Inc., Cabot Oil & Gas Corp., Callon Petroleum Co., Cheasapeake Energy, Corp., Climarex Energy, Co., Comstock Resources, Inc., Denbury Resources, Inc., Devon Energy Corp., Encana Corp., EOG Resources, Inc., International Coal Group, Inc., James River Coal Co., Massey Energy Co., Newfield Exploration Co., Nexen Inc., Noble Energy Inc., Peabody Energy Corp., Penn Virginia Corp., Pioneer Natural Resources Co., Rio Tinto PLC (ADR), St. Mary Land & Exploration, Stone Energy Corp., Ultra Petroleum Corp., and Westmorland Coal Co. The graph assumes that the value of the investment in CONSOL Energy common stock and each index was $100 at December 31, 2004. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2009.

	2004	2005	2006	2007	2008	2009
CONSOL Energy Inc.	100.0	160.1	159.5	283.1	223.6	299.2
Peer Group	100.0	158.1	161.4	221.7	170.8	218.8
S&P 500 Stock Index	100.0	104.8	120.4	125.8	89.2	115.1

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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 January 29, 2010, CONSOL Energy s board of directors declared a dividend of $0.10 per share, payable on February 19, 2010, to shareholders of record on February 9, 2010.

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 when our leverage ratio covenant is 2.50 to 1.00 or greater or our availability is less than $100 million. The leverage ratio was 0.87 to 1.00 and our availability was approximately $317 million at December 31, 2009. The credit facility does not permit dividend payments in the event of defaults. There were no defaults in the year ended December 31, 2009.

See Part III, Item 12. Security ownership of Certain Beneficial Owners and Management and Related Stockholders 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, 2009, 2008, 2007, 2006 and 2005 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, 2009 as required by the Noncontrolling Interest Topic of the Financial Accounting Standards Board Accounting Standards Codification. 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 report.

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STATEMENT OF INCOME DATA

(In thousands except per share data)

	For the Years Ended December 31, 2009	2008	2007	2006	2005
Sales Outside	$ 4,311,791	$ 4,181,569	$ 3,324,346	$ 3,286,522	$ 2,935,682
Sales Purchased Gas	7,040	8,464	7,628	43,973	275,148
Sales Gas Royalty Interests	40,951	79,302	46,586	51,054	45,351
Freight Outside	148,907	216,968	186,909	162,761	119,811
Other Income	113,186	166,142	196,728	170,861	107,131
Gain on Sale of 18.5% interest in CNX Gas					327,326
Total Revenue and Other Income	4,621,875	4,652,445	3,762,197	3,715,171	3,810,449
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	2,757,052	2,843,203	2,352,000	2,249,776	2,122,259
Purchased Gas Costs	6,442	8,175	7,162	44,843	278,720
Gas Royalty Interests Costs	32,376	73,962	39,921	41,879	36,501
Freight Expense	148,907	216,968	186,909	162,761	119,811
Selling, General and Administrative Expenses	130,704	124,543	108,664	91,150	80,700
Depreciation, Depletion and Amortization	437,417	389,621	324,715	296,237	261,851
Interest Expense	31,419	36,183	30,851	25,066	27,317
Taxes Other Than Income	289,941	289,990	258,926	252,539	228,606
Black Lung Excise Tax Refund	(728)	(55,795)	24,092		
Total Costs	3,833,530	3,926,850	3,333,240	3,164,251	3,155,765
Earnings Before Income Taxes	788,345	725,595	428,957	550,920	654,684
Income Taxes	221,203	239,934	136,137	112,430	64,339
Net Income	567,142	485,661	292,820	438,490	590,345
Less: Net Income Attributable to Noncontrolling Interest	(27,425)	(43,191)	(25,038)	(29,608)	(9,484)
Net Income Attributable to CONSOL Energy Inc. Shareholders	$ 539,717	$ 442,470	$ 267,782	$ 408,882	$ 580,861
Earnings Per Share:					
Basic	$ 2.99	$ 2.43	$ 1.47	$ 2.23	$ 3.17
Dilutive	$ 2.95	$ 2.40	$ 1.45	$ 2.20	$ 3.13
Weighted Average Number of Common Shares Outstanding:					
Basic	180,693,243	182,386,011	182,050,627	183,354,732	183,489,908
Dilutive	182,821,136	184,679,592	184,149,751	185,638,106	185,534,980
Dividends Paid Per Share	$ 0.40	$ 0.40	$ 0.31	$ 0.28	$ 0.28

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BALANCE SHEET DATA

(In thousands)

	Year Ended December 31, 2009	2008	2007	2006	2005
Working (deficiency) capital	$ (487,550)	$ (527,926)	$ (333,242)	$ 174,372	$ 194,578
Total assets	7,725,401	7,370,458	6,208,090	5,663,332	5,071,963
Short-term debt	472,850	557,700	247,500		
Long-term debt (including current portion)	468,302	490,752	507,208	552,263	442,996
Total deferred credits and other liabilities	3,849,428	3,716,021	3,325,231	3,228,653	2,726,563
CONSOL Energy Inc. Stockholders equity	1,785,548	1,462,187	1,214,419	1,066,151	1,025,356

OTHER OPERATING DATA

(unaudited)

	Year Ended December 31, 2009	2008	2007	2006	2005
Coal:					
Tons sold (in thousands) (D)(E)	58,123	66,236	65,462	68,920	70,401
Tons produced (in thousands)(E)	59,389	65,077	64,617	67,432	69,126
Productivity (tons per manday)(E)	38.21	36.80	41.29	38.41	37.95
Average production cost ($ per ton produced)(E)	$ 44.87	$ 41.08	$ 33.68	$ 32.53	$ 30.06
Average sales price of tons produced ($ per ton produced)(E)	$ 58.28	$ 48.77	$ 40.60	$ 38.99	$ 35.61
Recoverable coal reserves (tons in millions)(E)(F)	4,520	4,543	4,526	4,272	4,546
Number of active mining complexes (at end of period)	11	17	15	14	17
Gas:					
Net sales volumes produced (in billion cubic feet)(E)	94.4	76.6	58.3	56.1	48.4
Average sales price ($ per mcf)(E)(G)	$ 6.68	$ 8.99	$ 7.20	$ 7.04	$ 5.90
Average cost ($ per mcf)(E)	$ 3.44	$ 3.67	$ 3.33	$ 2.88	$ 2.69
Proved reserves (in billion cubic feet)(E)(H)	1,911	1,422	1,343	1,265	1,130

CASH FLOW STATEMENT DATA

(In thousands)

	Year Ended December 31, 2009	2008	2007	2006	2005
Net cash provided by operating activities	$ 945,451	$ 1,029,464	$ 684,033	$ 664,547	$ 409,086
Net cash used in investing activities	(845,341)	(1,098,856)	(972,104)	(661,546)	(74,413)
Net cash (used in) provided by financing activities	(173,015)	166,253	105,839	(119,758)	(455)

OTHER FINANCIAL DATA

(Unaudited)

(In thousands)

Year Ended December 31,

	2009	2008	2007	2006	2005
Capital expenditures	$ 920,080	$ 1,061,669	$ 1,039,838	$ 690,546	$ 532,796
EBIT(I)	786,520	685,574	421,978	531,009	664,451
EBITDA(I)	1,223,937	1,075,195	746,693	827,246	926,302
Ratio of earnings to fixed charges(J)	11.76	10.67	7.48	11.36	15.95

(A) See Note 25 of Notes to the Audited Consolidated Financial Statements 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 2,127,893 shares, 2,293,581 shares, 2,099,124 shares, 2,283,374 shares, and 2,045,072 shares for the year ended December 31, 2009, 2008, 2007, 2006 and 2005, respectively.

(C) On May 4, 2006, CONSOL Energy s Board of Directors declared a two-for-one stock split of the common stock. The stock split resulted in the issuance of approximately 92.5 million additional shares of common stock. Shares and earnings per share for all periods presented are reflected on a post-split basis.

(D) 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: 0.3 million tons in the year ended December 31, 2009, 1.7 million tons in the year ended December 31, 2008, 0.5 million tons in the year ended December 31, 2007, 1.3 million tons in the year ended December 31, 2006 and 1.5 million tons in year ended December 31, 2005.

(E) Amounts include intersegment transactions. For entities that are not wholly owned but in which CONSOL Energy owns an equity interest, includes a percentage of their net production, sales and reserves equal to CONSOL Energy s percentage equity ownership. For coal, the proportionate share of recoverable reserves for equity affiliates was 170, 171 and 179 tons at December 31, 2009, 2008 and 2007 respectively. Sales of coal produced by equity affiliates were 0.4 million tons in the year ended December 31, 2009, 0.2 million tons in the year ended December 31, 2008 and 0.1 million ton in the year ended December 31, 2007. Recoverable reserves and production amounts related to 2006 and 2005 for coal equity affiliates were immaterial. For gas, amounts include 100% of CNX Gas basis; they exclude the noncontrolling interest reduction. There was no equity in affiliates at December 31, 2009 and 2008. The proportionate share of proved gas reserves for equity affiliates was 3.6 Bcfe at December 31, 2007, 2.2 Bcfe at December 31, 2006 and 2.7 Bcfe at December 31, 2005. Sales of gas produced by equity affiliates were 0.32 Bcfe for the year ended December 31, 2007, 0.22 Bcfe for the year ended December 2006, 0.23 Bcfe for the year ended December 31, 2005.

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

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

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

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(I) EBIT is defined as earnings before deducting net interest expense (interest expense less interest income) and income taxes. EBITDA is defined as earnings before deducting net interest expense (interest expense less interest income), income taxes and depreciation, depletion and amortization. Although EBIT and 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 EBITDA. EBIT and 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 EBIT and 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 EBIT and 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 EBIT and EBITDA to financial net income is as follows:

(Unaudited)

(In thousands)

	Year Ended December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
Net Income	$ 539,717	$ 442,470	$ 267,782	$ 408,882	$ 580,861
Add: Interest expense	31,419	36,183	30,851	25,066	27,317
Less: Interest income	(5,052)	(2,363)	(12,792)	(15,369)	(8,066)
Less: Interest income included in black lung excise tax refund	(767)	(30,650)			
Add: Income tax expense	221,203	239,934	136,137	112,430	64,339
Earnings before interest and taxes (EBIT)	786,520	685,574	421,978	531,009	664,451
Add: Depreciation, depletion and amortization	437,417	389,621	324,715	296,237	261,851
Earnings before interest, taxes and depreciation, depletion and amortization (EBITDA)	$ 1,223,937	$ 1,075,195	$ 746,693	$ 827,246	$ 926,302

(J) 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.

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Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations.***

General

The U.S. economy began growing in the third quarter of 2009 and continued growing in the fourth quarter. Due to the significant fiscal spending and relaxed monetary policy in the United States, a modest recovery appears likely to continue in the U.S. through 2010. This should lead to an increase in demand for energy products from industrial customers, power generators and steel producers. Depending on the pace and sustainability of the recovery, we believe substantial opportunities exist for our metallurgical coal, thermal coal, and gas businesses.

Steel plant capacity utilization rates in the U.S. and globally continue to improve compared to last year. Domestic steel mills are using approximately 65% of their capacity, while Asian steel mills currently are using about 82% of their capacity. Chinese steel demand is again driving world demand and pricing for coking coal. Through its arrangement with Xcoal, CONSOL expects to increase its sales to Asian mills throughout 2010.

Going into the fourth quarter, thermal coal inventories were at historic highs. Because of the colder than normal weather in December 2009 and early January 2010, inventories at coal-fired power generators have been significantly drawn down, but are still somewhat higher than normal. Customers in our major market area (the PJM power pool) had an estimated 55-60 days of inventory on hand as of mid-January. The Company believes that thermal coal inventories could return to normal by mid-year. The outlook for a gradual economic recovery with strengthening demand and higher gas prices combined with the production declines over the past year are expected to tighten the thermal coal markets and support higher pricing. Higher gas prices in 2010 should result in power generators switching back from gas to coal based on dispatch economics. We anticipate up to 30 million tons of coal generation could displace natural gas generation in 2010. In addition, approximately 19 gigawatts of new coal-fired electricity generation capacity is set to come online by the end of 2012. This new demand, coupled with permanent cuts in coal production as well as safety and regulatory issues, is setting the stage for coal supply shortages over the next few years. With the continued build-out of scrubbers by generators, increased economic activity and its low cost position, CONSOL Energy is in a position to increase market share.

At the onset of the winter heating season, natural gas in storage fields was at record high levels. Because of much colder than normal weather in much of the U.S. from mid-December through mid-January, gas in storage has been drawn down to normal levels. The economic recovery is expected to positively affect industrial and commercial demand.

CONSOL Energy established an arrangement with Xcoal to market CONSOL Energy coal in Asia. In January 2010, we sold a vessel of high-vol coking coal from Bailey Mine in Northern Appalachia to merchant coke plants in China. This re-branding of Bailey Mine coal from a premium thermal coal to a high-volatile coking coal has meaningful implications for CONSOL Energy s 2010 earnings and beyond. Our goal in 2010 is to sell 500,000 tons of Northern Appalachia high-volatile coking coal into Asian markets.

In 2009, a fish kill occurred in Dunkard Creek, which is a creek with segments in both Pennsylvania and West Virginia. The fish kill was caused by the growth of golden brown algae in the creek, which appears to be an invasive species, not indigenous to the area. A CONSOL Energy subsidiary discharges water into Dunkard Creek, after treatment, from its Blacksville No. 2 Mine and from its Loveridge Mine. This water has levels of chlorides that are higher than West Virginia in-stream limits. The subsidiary is subject to a state administrative order in West Virginia that requires compliance in 2013 with effluent limits for chlorides for discharges from four active and two closed underground coal mines in northern West Virginia. Given the volumes of water involved and the options that are available to timely meet the effluent limits, it is likely that it will be necessary to construct one or more treatment facilities using advanced water treatment technologies. These requirements may cause CONSOL Energy to incur additional costs that could adversely affect our operating results, financial condition and cash flows.

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Results of Operations

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

Net Income Attributable to CONSOL Energy Shareholders

Net income attributable to CONSOL Energy shareholders changed primarily due to the following items

(table in millions):

	2009	2008	Dollar Variance	Percentage Change
Sales Outside	$ 4,312	$ 4,182	$ 130	3.1%
Sales Purchased Gas	7	8	(1)	(12.5)%
Sales Gas Royalty Interest	41	79	(38)	(48.1)%
Freight-Outside	148	217	(69)	(31.8)%
Other Income	113	166	(53)	(31.9)%
Total Revenue and Other Income	4,621	4,652	(31)	(0.7)%
Coal Cost of Goods Sold and Other Charges	2,757	2,843	(86)	(3.0)%
Purchased Gas Costs	6	8	(2)	(25.0)%
Gas Royalty Interest Costs	32	74	(42)	(56.8)%
Total Cost of Goods Sold	2,795	2,925	(130)	(4.4)%
Freight Expense	148	217	(69)	(31.8)%
Selling, General and Administrative Expense	132	125	7	5.6%
Depreciation, Depletion and Amortization	437	390	47	12.1%
Interest Expense	32	36	(4)	(11.1)%
Taxes Other Than Income	290	290		
Black Lung Excise Tax Refund	(1)	(56)	55	(98.2)%
Total Costs	3,833	3,927	(94)	(2.4)%
Earnings Before Income Taxes and Noncontrolling Interest	788	725	63	8.7%
Income Tax Expense	221	240	(19)	(7.9)%
Earnings Before Noncontrolling Interest	567	485	82	16.9%
Noncontrolling Interest	27	43	(16)	(37.2)%
Net Income Attributable to CONSOL Energy Inc. Shareholders	$ 540	$ 442	$ 98	22.2%

Net income attributable to CONSOL Energy shareholders for the year ended December 31, 2009 was $540 million compared to $442 million in the year ended December 31, 2008. Net income attributable to CONSOL Energy shareholders for the year ended December 31, 2009 increased in comparison to the year ended December 31, 2008 primarily due to:

- Higher average thermal coal sales prices;

- Higher gas sales volumes; and

- Lower average cost per unit of gas sold.

Improvements in net income attributable to CONSOL Energy shareholders were offset, in part, by the following items:

- Lower volume of thermal and metallurgical coal sold;
- Lower average sales prices for gas volumes sold;
- Lower average sales prices for metallurgical tons sold;
- Higher average cost per ton of coal sold;

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Business interruption insurance settlement of $50 million recognized in the year ended December 31, 2008 related to the Buchanan roof collapse incident; and

Black lung excise tax refunds of $56 million recognized in the year ended December 31, 2008.

See discussion below for additional details of the changes in net income in the year-to-year comparison. The cost per unit below is not necessarily indicative of unit costs in the future.

Revenue

Revenue and other income decreased due to the following items:

	2009	2008	Dollar Variance	Percentage Change
Sales:				
Produced Coal Thermal	$ 3,148	$ 2,669	$ 479	17.9%
Produced Coal Metallurgical	223	398	(175)	(44.0)%
Purchased Coal	39	118	(79)	(66.9)%
Produced Gas	629	681	(52)	(7.6)%
Industrial Supplies	195	196	(1)	(0.5)%
Other	78	120	(42)	(35.0)%
Total Sales-Outside	4,312	4,182	130	3.1%
Gas Royalty Interest	41	79	(38)	(48.1)%
Purchased Gas	7	8	(1)	(12.5)%
Freight Revenue	148	217	(69)	(31.8)%
Other Income	113	166	(53)	(31.9)%
Total Revenue and Other Income	$ 4,621	$ 4,652	$ (31)	(0.7)%

The increase in company produced thermal coal sales revenue during the year ended December 31, 2009 was due to the higher average price per ton sold, offset, in part, by lower sales volumes of company produced thermal coal sold.

	2009	2008	Variance	Percentage Change
Produced Thermal Tons Sold (in millions)	55.1	61.4	(6.3)	(10.3)%
Average Sales Price Per Thermal Ton	$ 57.11	$ 43.44	$ 13.67	31.5%

The increase in average sales price in the year-to-year comparison primarily reflects higher prices negotiated in previous periods when there was a significant increase in the global demand for coal. Sales of company produced coal shipments decreased in the current period due to delivery deferments of Central and Northern Appalachian coals. Coal consumption by the electric power sector continued to decline during the year. In the year-to-year comparison of the thermal coal changes, the increased pricing improved sales income by $753 million. This was partially offset by lower thermal tons sold which reduced sales income by approximately $274 million dollars.

The decrease in company produced metallurgical coal sales revenue during the year ended December 31, 2009 was due to the lower average price per ton sold and lower sales volumes of company produced metallurgical coal sold.

	2009	2008	Variance	Percentage Change
Produced Metallurgical Tons Sold (in millions)	2.3	2.9	(0.6)	(20.7)%

Average Sales Price Per Metallurgical Ton	$ 96.68	$ 136.92	$ (40.24)	(29.4)%

The decrease in average sales price for metallurgical coal in the year-to-year comparison reflects lower prices realized due to a downturn in the domestic and international steel business and the deferment of previously negotiated pricing into future periods. Sales of company produced metallurgical coal decreased in the current period due to a downturn in the domestic and international steel business resulting in reduced demand for metallurgical coal and the idling of the Buchanan Mine from March 1, 2009 to August 7, 2009. In the year-to-year comparison of metallurgical coal changes, the decreased pricing impaired sales income by $93 million. Also, lower metallurgical tons sold impaired sales income by approximately $82 million dollars.

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 decrease of $79 million in purchased coal sales revenue was primarily due to a decrease in demand in the year-to-year comparison, offset, in part, by higher sales prices.

The decrease of $52 million in produced gas sales revenue in the year ended December 31, 2009 compared to the year ended December 31, 2008 was due to lower average sales price per thousand cubic feet sold, offset, in part, by higher sales volumes.

	2009	2008	Variance	Percentage Change
Produced Gas Sales Volume (in billion cubic feet)	93.6	75.3	18.3	24.3%
Average Sales Price Per thousand cubic feet	$ 6.72	$ 9.04	$ (2.32)	(25.7)%

Sales volumes increased as a result of additional wells coming online from our on-going drilling program. The decrease in average sales price is the result of the general market price decreases in the year-to-year comparison. The general market price decline was offset, in part, by the various gas swap transactions entered into by CNX Gas. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 51.6 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2009 at an average price of $8.76 per thousand cubic feet. In the year ended December 31, 2008, these financial hedges represented approximately 43.4 billion cubic feet at an average price of $9.25 per thousand cubic feet.

The $1 million decrease in revenues from the sale of industrial supplies was primarily due to lower sales volumes. Economic conditions had a negative impact on major customers, particularly those serving the auto and housing markets.

The $42 million decrease in other sales was attributable to decreased revenues from barge towing and terminal services. The decrease is related to lower tonnage moved by the barge towing and terminal services in the year ended December 31, 2009 compared to the year ended December 31, 2008. Lower tonnage moved reflects the weak economic environment which has reduced the volume of products moved on the rivers in the year ended December 31, 2009.

Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by CNX Gas on their behalf. The decrease in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the year-to-year change.

	2009	2008	Variance	Percentage Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	9.8	8.5	1.3	15.3%
Average Sales Price Per thousand cubic feet	$ 4.17	$ 9.32	$ (5.15)	(55.3)%

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Purchased gas sales volumes represent volumes of gas, sold at market prices, that were purchased from third-party producers.

	2009	2008	Variance	Percentage Change
Purchased Gas Sales Volumes (in billion cubic feet)	1.6	1.0	0.6	60.0%
Average Sales Price Per thousand cubic feet	$ 4.46	$ 8.76	$ (4.30)	(49.1)%

Freight revenue is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e., rail, barge, truck, etc.) used for the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is the amount billed to customers for transportation costs incurred. Freight revenue has decreased $69 million in 2009 primarily due to lower domestic shipments to customers for whom CONSOL Energy pays the freight and then passes on the cost to the customer. Freight revenue also decreased due to fewer export sales made to customers whom CONSOL Energy pays the ocean-going freight and then passes the cost to the customer.

Other income consists of interest income, gain or loss on the disposition of assets, equity in earnings of affiliates, service income, royalty income and miscellaneous income.

	2009	2008	Dollar Variance	Percentage Change
Business interruption proceeds	$	$ 50	$ (50)	(100.0)%
Gain on sale of assets	15	23	(8)	(34.8)%
Contract towing	5	11	(6)	(54.5)%
Proceeds from relinquishment of mining rights		6	(6)	(100.0)%
Royalty income	17	21	(4)	(19.0)%
Recognition of unrealized gains on options	2		2	100.0%
Interest income	5	2	3	150.0%
Equity in earnings of affiliates	16	11	5	45.5%
Contract settlement	12		12	100.0%
Other miscellaneous	41	42	(1)	(2.4)%
Total other income	$ 113	$ 166	$ (53)	(31.9)%

In March 2008, CONSOL Energy received notice from its insurance carriers that $50 million would be paid as final settlement of the insurance claim related to the July 2007 Buchanan Mine incident that idled the mine. The $50 million represented business interruption coverage which was recognized in other income; the coal segment recognized $42 million and the gas segment recognized $8 million. The final settlement brought the total amount recovered from insurance carriers to $75 million, the maximum allowed per covered event.

Gain on sale of assets decreased $8 million in the year-to-year comparison due to 2008 including the sale of an idled facility which included the transfer of the mine closing liabilities to the buyer. This transaction resulted in $8 million pre-tax gain in 2008. Both periods also include various miscellaneous transactions, none of which were individually material.

Contract towing revenue has decreased approximately $6 million due primarily to the general slow-down in the economy negatively impacting the volume of material being shipped via river transportation.

The year ended December 31, 2008 includes $6 million of proceeds received from a third party in order for CONSOL Energy to relinquish the mining of certain in-place coal reserves.

Royalty income decreased $4 million primarily due to lower volumes of CONSOL Energy coal produced by third-parties.

In 2009, mark-to-market adjustments for free standing coal sales options resulted in approximately a $2 million reversal of previously recognized unrealized losses. The reversal of losses was due to the options expiring during the year ended December 31, 2009.

Interest income increased $3 million primarily due to higher average cash balances available to invest in the year-to-year comparison.

Equity in earnings of affiliates increased $5 million in the year ended December 31, 2009 due to various transactions entered into by our equity affiliates throughout both periods, none of which were individually material.

In 2009, $12 million of income was recognized related to contracts with certain customers that were unable to take delivery of previously contracted coal tonnage. These customers agreed to buy out their contracts in order to release them from the requirement of taking delivery of previously committed tons.

Other miscellaneous income decreased $1 million in the year-to-year comparison due to various miscellaneous transactions that occurred throughout both periods, none of which were individually material.

Costs

Cost of goods sold and other charges decreased due to the following:

	2009	2008	Dollar Variance	Percentage Change
Cost of Goods Sold and Other Charges				
Produced Coal	$ 1,968	2,031	$ (63)	(3.1)%
Purchased Coal	46	124	(78)	(62.9)%
Produced Gas	204	184	20	10.9%
Industrial Supplies	185	186	(1)	(0.5)%
Closed and Idle Mines	114	78	36	46.2%
Other	240	240		
Total Cost of Goods Sold and Other Charges Outside	2,757	2,843	(86)	(3.0)%
Gas Royalty Interest	32	74	(42)	(56.8)%
Purchased Gas	6	8	(2)	(25.0)%
Total Cost of Goods Sold	$ 2,795	2,925	$ (130)	(4.4)%

Produced coal cost of goods sold and other charges decreased primarily due to lower sales volumes, offset, in part, by an 8.6% increase in average unit cost per ton sold.

	2009	2008	Variance	Percentage Change
Produced Tons Sold (in millions)	57.4	64.3	(6.9)	(10.7)%
Average Cost of Goods Sold and Other Charges per Ton	$ 34.27	$ 31.57	$ 2.70	8.6%

Average cost of goods sold and other charges per unit increased in the year-to-year comparison primarily due to an increase in average unit costs related to the following items:

In general, average cost of goods sold per unit has increased due to the reduced amount of tons sold from CONSOL Energy mines. The reduction in tons sold reflects the weak economic environment which has affected electricity generation and correspondingly the demand for coal. Fixed costs incurred at our mining operations are now spread over fewer tons sold, which has negatively impacted average unit costs.

Supply costs have increased $1.39 per ton sold related to higher supply and maintenance costs at several locations. Additional supply and maintenance projects were related to additional preparation plant maintenance, additional belt advancement costs, additional mining equipment maintenance, additional roof support, additional use of contract labor to complete belt projects and additional water handling costs. These increased supply and maintenance costs were offset, in part, by fewer seals being constructed in previously mined areas. Average unit costs of supplies were also impacted by lower sales tons in the year-to-year comparison.

Labor costs have increased $0.91 per ton sold due to the effects of wage increases at the union and non-union mines. These contracts call for specified hourly wage increases in each year of the contract. The average increase in unit cost for labor was also impacted by lower sales volumes due to the economic environment as discussed above.

United Mine Workers of America (UMWA) health and retirement plan expenses have increased $0.30 per ton sold primarily due to the effects of the 2007 labor contract that require additional contributions to be made into employee benefit funds. The contribution increase over 2007 was $0.42 per United Mine Worker of America hour worked. The average increase in unit costs for health and retirement plans was also impacted by lower sales tons in the year-to-year comparison.

Subsidence cost increased $0.30 per ton sold primarily due to the year ended December 31, 2009 including additional expenses related to work to be performed on streams that have been impacted by underground mining in Pennsylvania. The average increase in unit costs for subsidence was also impacted by lower sales tons in the year-to-year comparison.

Other costs per unit on a net basis have increased $0.05 per ton sold due to various transactions that have occurred throughout both periods, none of which were individually material.

These increases in costs were offset, in part, by the following decrease:

Contract Mining Fees decreased $0.25 per ton sold due to lower contractor usage in the year ended December 31, 2009 compared to the year ended December 31, 2008.

Purchased coal cost of goods sold consists of costs from processing purchased coal in our preparation plants for blending purposes to meet customer coal specifications, coal purchased and sold directly to the customer and costs for processing third party coal in our preparation plants. The decrease of $78 million in purchased coal cost of goods sold and other charges in 2009 was primarily due to lower volumes purchased.

Gas cost of goods sold and other charges increased primarily due to a 24.3% increase in volumes of produced gas sold, offset, in part, by lower average cost per unit sold.

	2009	2008	Variance	Percentage Change
Produced Gas Sales Volumes (in billion cubic feet)	93.6	75.3	18.3	24.3%
Average Cost per thousand cubic feet	$ 2.36	$ 2.51	$ (0.15)	(6.0)%

Average costs per unit decreased in the year ended December 31, 2009 as a result of several factors:

Well service costs have decreased by $0.07 per thousand cubic feet due to lower contract service rig hours needed as a result of less pump maintenance being required in 2009.

Gob collection charges were $0.04 per thousand cubic feet lower in the year-to-year comparison. Lower gob collection charges per unit were primarily due to the Buchanan longwall being idled throughout some of 2009.

Compression expenses decreased $0.03 per thousand cubic feet primarily due to a reduction in the number of compressors utilized in the Northern Appalachian production field. Due to the slow-down in the drilling program in Northern Appalachia, rented compressors have been returned to more appropriately design the gathering fields for existing needs.

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Other costs have decreased $0.22 per thousand cubic feet primarily due to the impact of additional volumes of gas sold during the year ended December 31, 2009. Dollars spent remained consistent in the year-to-year comparisons, therefore additional volumes decreased the unit costs.

These decreases in unit costs were offset, in part, by the following:

Idle drilling costs were $0.09 per thousand cubic feet related to idling various drilling rigs throughout the company. Some of CNX Gas drilling contracts require minimum payments be made to the contracting party when drilling rigs are not being used. The CNX Gas drilling program has been slowed down pending a change in the economic environment. These charges resulted in an increase to costs.

Firm transportation costs increased $0.08 per thousand cubic feet primarily due to acquiring additional capacity in the Northern Appalachian region after December 31, 2008.

Power and fuel costs increased $0.04 per thousand cubic feet due to a power rate increase which occurred after December 31, 2008. Also, the increase was due to additional compressors being placed in service after December 31, 2008 along the existing gathering system in the Central Appalachian production field in order to flow the increasing gas volumes more efficiently.

Industrial supplies cost of goods sold decreased $1 million primarily due to decreased sales volumes.

Closed and idle mine cost of goods sold increased approximately $36 million in 2009 compared to 2008. Approximately $38 million of increased expenses were incurred at Mine 84 to pull underground equipment out of the mine in preparation of idling and to construct seals to close sections of the underground mine works so that the mine can be maintained in a more efficient manner. Increases were also attributable to the idled Shoemaker Mine incurring approximately $11 million of additional expenses in the current period related to the continued maintenance of the mine in an idled status. Closed and idle mine cost of goods sold also increased $7 million primarily due to the periodic idling of various other locations throughout 2009 due to the economic environment. These increases were offset, in part, by reductions of $20 million related to mine closing, reclamation and water treatment liabilities. These decreases primarily related to adjustments in engineering estimates of water quality and flows, as well as changes in the credit adjusted risk free interest rates.

Other cost of goods sold remained consistent due to the following items:

	2009	2008	Dollar Variance	Percentage Change
Incentive compensation	$ 51	$ 33	$ 18	54.5%
Legal settlement	15		15	100.0%
Cease use expense	14		14	100.0%
Dry hole and other costs	9	1	8	800.0%
Stock-based compensation	38	34	4	11.8%
Severance expense	4		4	100.0%
Ward superfund site	3	7	(4)	(57.1)%
Sales contract buyout	13	19	(6)	(31.6)%
Profit splits		15	(15)	(100.0)%
Buchanan roof collapse		17	(17)	(100.0)%
Terminal/River operations	59	81	(22)	(27.2)%
Miscellaneous other	34	33	1	3.0%
Other cost of goods sold and other charges	$ 240	$ 240	$	

The incentive compensation program is designed to increase compensation to eligible employees when CONSOL Energy reaches predetermined production, safety and cost targets and the employees reach predetermined performance targets. Incentive compensation expense increased $18 million in 2009 due to exceeding the predetermined targets.

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Legal settlement of $15 million represents the amount expensed for the settlement of the Levisa Action and the Pobst/Combs Action.

Approximately $14 million of cease use expense relates to the relocation of the CONSOL Energy and CNX Gas corporate office and the cease use of the old facilities. Accordingly, a liability for the present value of the remaining lease payments for the previous corporate offices has been recognized in Cost of Goods Sold and Other Charges and resulted in $14 million of expense.

Dry hole and other costs of $9 million were incurred by the gas segment in the year ended December 31, 2009. Dry hole and other costs were incurred in 2009 related to the determination that certain areas where an exploration well was drilled would not be economical to pursue. The costs for the exploration well, which were previously capitalized, were expensed. Other costs include costs associated with certain leased property that will no longer be held due to the determination that the area would not be economical to pursue. Also, costs related to particular permits for areas where management has determined that no drilling will take place have been expensed.

Stock-based compensation expense increased $4 million in the year-to-year comparison primarily due to $3 million of fair value adjustments associated with the exchange offer to convert CNX Gas performance share units into CONSOL restricted stock units. The year ended December 31, 2009 also includes additional expense due to expanding the stock-based compensation program to include additional employees. The year ended December 31, 2008 included a reduction to expense related to the CNX Gas performance share units to reflect the lower market price of CNX Gas shares at December 31, 2008 compared to its peer group. The CNX Gas performance share units were replaced with a CONSOL Energy restricted stock units in 2009.

Severance pay relates to the administrative staff reductions in force and resulted in $4 million of expense in 2009.

Ward transformer superfund site expense was $4 million lower in the year ended December 31, 2009 compared to the year ended December 31, 2008. The expense in each period represents CONSOL Energy s portion of the latest estimate of cost to remediate the site. See Note 24-Commitments and Contingencies of Item 8 of the Consolidated Financial Statements for additional detail.

The year ended December 31, 2008 includes adjustments related to CONSOL Energy agreements to buy out coal sales contracts with several customers in order to release tons committed under lower priced contracts for sale to other customers at higher prices. The year ended December 31, 2009 includes fewer customer buyouts.

In the year ended December 31, 2008, cost of goods sold and other charges includes $15 million related to contracts with certain customers who were unable to take delivery of previously contracted coal tonnage. These customers agreed to allow CONSOL Energy to sell the released tonnage, but required CONSOL Energy to split the incremental sales price over the original contract sales price evenly with them. The $15 million represents the additional sales price received for the tonnage sold that is owed to the original customer.

In July 2007, production at the Buchanan Mine was suspended after several roof falls in previously mined areas damaged some of the ventilation controls inside the mine, requiring a general evacuation of the mine. In 2008, $17 million of cost of goods sold and other charges related to the Buchanan Mine event were incurred.

Terminal/River operation charges have decreased approximately $22 million in the year-to-year comparison due to lower tonnage moved and lower employee counts throughout the year ended December 31, 2009.

Miscellaneous other cost of goods sold and other charges increased $1 million due to various transactions throughout both years, none of which were individually material.

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Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by CNX Gas on their behalf. The decrease in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the year-to-year change.

	2009	2008	Variance	Percentage Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	9.8	8.5	1.3	15.3%
Average Cost Per thousand cubic feet	$ 3.30	$ 8.69	$ (5.39)	(62.0)%

Purchased gas costs represent volumes of gas purchased from third party producers that we sell at market prices. Purchased gas cost volumes also reflect the impact of pipeline imbalances. The decrease in cost of goods sold and other charges related to purchased gas represents overall price changes and contractual differences among customers in the year-to-year comparison.

	2009	2008	Variance	Percentage Change
Purchased Gas Cost Volumes (in billion cubic feet)	1.7	1.0	0.7	70.0%
Average Cost Per thousand cubic feet	$ 3.75	$ 8.13	$ (4.38)	(53.9)%

Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e., rail, barge, truck, etc.) used for the customers to which CONSOL Energy contractually provides transportation services. Freight expense is the amount billed to customers for transportation costs incurred. Freight expense has decreased $69 million in the year ended December 31, 2009 primarily due to lower domestic shipments to customers whom CONSOL Energy pays the freight and then passes on the cost to the customer. Freight revenue also decreased due to fewer export sales made to customers whom CONSOL Energy pays the ocean-going freight and then passes the cost to the customer.

Selling, general and administrative costs have increased due to the following items:

	2009	2008	Dollar Variance	Percentage Change
Rentals	$ 9	$ 3	$ 6	200.0%
Wages, salaries and related benefits	63	61	2	3.3%
Association/charitable contributions	12	12		
Advertising and promotion	5	6	(1)	(16.7)%
Professional, consulting and other purchased services	26	27	(1)	(3.7)%
Other	17	16	1	6.3%
Total Selling, General and Administrative	$ 132	$ 125	$ 7	5.6%

Rentals have increased $6 million primarily due to rent expense related to the new CONSOL Energy headquarters, offset, in part, by reduced rent related to the previous CONSOL Energy and CNX Gas corporate office space that is no longer used.

Wages, salaries and related benefits have increased approximately $2 million primarily due to annual salary increases and additional recruiting expenses.

Association assessments and charitable contributions have remained consistent in the year-to-year comparison.

Advertising and promotion expenses have decreased $1 million in the year-to-year comparison due to the timing of various campaigns.

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Costs of professional, consulting and other purchased services have decreased $1 million related to various corporate initiatives, none of which are individually material.

Other selling, general and administrative costs increased $1 million related to various transactions none of which are individually material.

Depreciation, depletion and amortization increased due to the following items:

	2009	2008	Dollar Variance	Percentage Change
Coal	$ 307	$ 299	$ 8	2.7%
Gas:				
Production	86	51	35	68.6%
Gathering	21	19	2	10.5%
Total Gas	107	70	37	52.9%
Other	23	21	2	9.5%
Total Depreciation, Depletion and Amortization	$ 437	$ 390	$ 47	12.1%

The $8 million increase in coal depreciation, depletion and amortization was primarily attributable to assets placed in service during 2009.

The increase in gas production depreciation, depletion and amortization was primarily due to increased volumes produced, combined with an increase in the units of production rates for the Northern Appalachian region in the year-to-year comparison. These rates increased due to the higher proportion of capital assets placed in service versus the proportion of proved developed reserve additions. These rates are generally calculated using the net book value of assets at the end of the previous year divided by either proved or proved developed reserves. Production asset depreciation also increased due to the recalculation of rates in 2009 related to the Marcellus Shale wells and various other assets being placed in service during 2009.

Gas gathering depreciation, depletion and amortization is recorded using the straight-line method and increased $2 million in the year-to-year comparison due to various assets being placed in service during 2009.

Other depreciation increased $2 million in the year-to-year comparison due to various assets being placed in service during 2009, none of which were individually material.

Interest expense decreased in the year ended December 31, 2009 compared to the year ended December 31, 2008 due to the following items:

	2009	2008	Dollar Variance	Percentage Change
Revolver	$ 6	$ 11	$ (5)	(45.5)%
Interest on unrecognized tax benefits	2	2		
Capitalized leases	6	6		
Long-term secured notes	27	27		
Other	(9)	(10)	1	(10.0)%
Total Interest Expense	$ 32	$ 36	$ (4)	(11.1)%

Revolver interest expense is related to the amounts drawn on the credit facility. The decrease is related to lower interest rates on the facility in 2009 compared to 2008, offset, in part, by higher average amounts drawn in 2009.

Interest on unrecognized tax benefits, capitalize leases and long-term secured notes remained consistent in the year-to-year comparison.

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Other interest expense increased $1 million in the year-to-year comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Taxes other than income remained consistent in the year-to-year comparison.

	2009	2008	Dollar Variance	Percentage Change
Production taxes:				
Coal	$ 177	$ 169	$ 8	4.7%
Gas	6	20	(14)	(70.0)%
Total Production Taxes	183	189	(6)	(3.2)%
Other taxes:				
Coal	87	84	3	3.6%
Gas	7	6	1	16.7%
Other	13	11	2	18.2%
Total Other Taxes	107	101	6	5.9%
Total Taxes Other Than Income	$ 290	$ 290	$	

Increased coal production taxes are primarily due to higher severance taxes attributable to the increase in average sales price for produced coal. These improvements were offset, in part, by lower coal production volumes in the year-to-year comparison.

Gas production taxes decreased $14 million due to lower severance taxes attributable to lower average sales prices for gas, offset, in part, by higher gas sales volumes. Lower severance taxes in the year-to-year comparison are also related to a revised estimate of a pending litigation settlement.

Other coal taxes have increased approximately $3 million primarily due to higher property taxes related to reassessments on property primarily in West Virginia and Pennsylvania owned by CONSOL Energy. The increase was also due to a reduction in the tax credit generated by production in the state of Virginia as a result of the idling of the longwall at the Buchanan Mine which reduced production during a portion of 2009.

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

Other taxes have increased $2 million in the year-to-year comparison due to various transactions that occurred throughout both periods, none of which were individually material.

In 2008, $56 million of refunds related to black lung excise taxes were recognized. The refunds related to the Emergency Economic Stabilization Act of 2008 (the EESA Act) which was signed into law on October 3, 2008. The EESA Act contained a section that authorized certain coal producers and exporters who had filed a black lung excise tax (BLET) return on or after October 1, 1990, to request a refund of the BLET paid on export sales. The EESA Act required the U.S. Treasury to refund an amount equal to the BLET erroneously paid on export sales in prior years along with interest computed at the statutory rates applicable to overpayments. CONSOL Energy recognized, and subsequently received, approximately $56 million of BLET refunds. Approximately $1 million of additional interest income was recognized in 2009 to adjust estimated interest on these claims to the amount of interest received.

Income Taxes

	2009	2008	Variance	Percentage Change

Earnings Before Income Taxes	$ 788	$ 725	$ 63	8.7%
Income Tax Expense	$ 221	$ 240	$ (19)	(7.9)%
Effective Income Tax Rate	28.1%	33.1%	(5.0)%	

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CONSOL Energy s effective income tax rate is sensitive to changes to the relationship between pre-tax earnings and percentage depletion. The proportion of coal pre-tax earnings and gas pre-tax earnings also impacts the benefit of percentage depletion on the effective tax rate. See Note 6 Income Taxes in Item 8, Consolidated Financial Statements of this Form 10-K.

Noncontrolling Interest

Noncontrolling interest represents 16.7% of CNX Gas net income which CONSOL Energy does not own.

Results of Operations

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

Net Income

Net income changed primarily due to the following items (table in millions):

	2008	2007	Dollar Variance	Percentage Change
Sales Outside	$ 4,182	$ 3,324	$ 858	25.8%
Sales Purchased Gas	8	8		
Sales Gas Royalty Interest	79	47	32	68.1%
Freight Outside	217	187	30	16.0%
Other Income	166	196	(30)	(15.3)%
Total Revenue and Other Income	4,652	3,762	890	23.7%
Coal Cost of Goods Sold and Other and Purchased Charges	2,843	2,351	492	20.9%
Purchased Gas Costs	8	7	1	14.3%
Gas Royalty Interest Costs	74	40	34	85.0%
Total Cost of Goods Sold	2,925	2,398	527	22.0%
Freight Expense	217	187	30	16.0%
Selling, General and Administrative Expense	125	109	16	14.7%
Depreciation, Depletion and Amortization	390	325	65	20.0%
Interest Expense	36	31	5	16.1%
Black Lung Excise Tax Refund	(56)	24	(80)	(333.3)%
Taxes Other Than Income	290	259	31	12.0%
Total Costs	3,927	3,333	594	17.8%
Earnings Before Income Taxes and Minority Interest	725	429	296	69.0%
Income Tax Expense	240	136	104	76.5%
Earnings Before Minority Interest	485	293	192	65.5%
Minority Interest	43	25	18	72.0%
Net Income	$ 442	$ 268	$ 174	64.9%

CONSOL Energy had net income of $442 million for the year ended December 31, 2008 compared to $268 million in the year ended December 31, 2007. Net income for 2008 increased in comparison to 2007 due to:

higher average prices received for both coal and gas;

higher volumes of gas sold;

2007 included a total of approximately $94 million of pre-tax expenses, net of insurance recoveries, related to the Buchanan Mine incident that occurred in July 2007 which idled the mine through March 2008; the 2008 period includes approximately $28.6 million of pre-tax income related to this incident;

Black Lung excise tax refund receivable recognized for taxes paid in 1991-1993 due to legislation passed in October 2008; and

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Receivable write off of $24 million in 2007 related to the Supreme Court decision which rendered the Black Lung Excise Tax receivable for 1991-1993 uncollectible.

These increases in net income were offset, in part, by:

an asset exchange and an asset sale in 2007 that resulted in pretax income of approximately $100 million and net income of approximately $59 million;

increased unit cost of goods sold and other charges for both coal and gas.

See below for a more detailed description of variances noted. The cost per unit below is not necessarily indicative of unit costs in the future.

Revenue

Revenue and other income increased due to the following items:

	2008	2007	Dollar Variance	Percentage Change
Sales:				
Produced Coal	$ 3,067	$ 2,640	$ 427	16.2%
Purchased Coal	118	38	80	210.5%
Produced Gas	681	410	271	66.1%
Industrial Supplies	196	147	49	33.3%
Other	120	89	31	34.8%
Total Sales Outside	4,182	3,324	858	25.8%
Gas Royalty Interest	79	47	32	68.1%
Purchased Gas	8	8		
Freight Revenue	217	187	30	16.0%
Other Income	166	196	(30)	(15.3)%
Total Revenue and Other Income	$ 4,652	$ 3,762	$ 890	23.7%

The increase in company produced coal sales revenue during 2008 was due to higher average prices, offset, in part, by slightly lower volumes of produced coal sold.

	2008	2007	Variance	Percentage Change
Produced Tons Sold (in millions)	64.3	64.8	(0.5)	(0.8)%
Average Sales Price Per Ton	$ 47.66	$ 40.74	$ 6.92	17.0%

The increase year-to-year in the average sales prices of coal was the result of global coal fundamentals being more favorable in 2008. Concerns regarding the adequacy of global supplies of coal had strengthened both the international and domestic coal prices and had increased the opportunity for U.S. producers to increase exports of coal. Sales tons were slightly lower in the year-to-year comparison.

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 increase of $80 million in company-purchased coal sales revenue was primarily due to an increase in volumes of purchased coal sold in the year-to-year comparison.

The increase in produced gas sales revenue in 2008 compared to 2007 was primarily due to higher average sales prices and higher volumes of gas sold.

	2008	2007	Variance	Percentage Change
Produced Gas Sales Volumes (in billion cubic feet)	75.7	57.1	18.6	32.6%
Average Sales Price Per thousand cubic feet	$ 9.00	$ 7.18	$ 1.82	25.3%

The increase in average sales price is the result of CNX Gas, an 83.3% subsidiary at December 31, 2008, realizing general market price increases in the year-to-year comparison. CNX Gas periodically enters into various gas swap transactions that qualify as financial cash flow hedges. These gas swap transactions exist parallel to the underlying physical transactions. These financial hedges represented approximately 43.4 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2008 at an average price of $9.25 per thousand cubic feet. In the prior year, these financial hedges represented approximately 18.4 billion cubic feet at an average price of $8.01 per thousand cubic feet. Sales volumes increased as a result of additional wells coming online from our on-going drilling program. Also, prior year sales volumes were impacted by the deferral of production at the Buchanan Mine.

The $49 million increase in revenues from the sale of industrial supplies was primarily due to the July 2007 acquisition of Piping & Equipment, Inc. in addition to an overall increase in sales volumes and higher sales prices.

The $31 million increase in other sales was attributable to increased revenues from barge towing and terminal services. The increase was primarily related to revenue generated from the barge towing operations having higher average rates for services rendered compared to the prior year. The barge towing operations have also increased thru-put tons and delivered tons in 2008. Increases in other sales revenues were also attributable to higher terminal services as a result of additional thru-put tons in 2008. The higher terminal revenues were offset, in part, due to services being suspended for approximately one month due to maintenance needed on a pier in Baltimore.

	2008	2007	Variance	Percentage Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	8.5	7.2	1.3	18.1%
Average Sales Price Per thousand cubic feet	$ 9.32	$ 6.44	$ 2.88	44.7%

Gas royalty interest sales volumes represent the revenues related to the portion of production belonging to royalty interest owners sold by CNX Gas on their behalf. The increase in market prices, contractual differences among leases and the mix of average and index prices used in calculating royalties contributed to the year-to-year change.

	2008	2007	Variance	Percentage Change
Purchased Sales Volumes (in billion cubic feet)	1.0	1.1	(0.1)	(9.1)%
Average Sales Price Per thousand cubic feet	$ 8.76	$ 7.19	$ 1.57	21.8%

Purchased gas sales volumes represent volumes of gas that were sold at market prices that were purchased from third-party producers, less gathering fees.

Freight revenue is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e., rail, barge, truck, etc.) used for the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is the amount billed to customers for transportation costs incurred. Freight revenue has increased $30 million in 2008 due primarily to freight associated with AMVEST, which was acquired on July 31, 2007. Freight revenue has also increased due to higher freight rates being charged for

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exported tons. These increases in freight revenue were offset, in part, by lower export tons shipped in 2008 compared to 2007. There were 7.0 million tons and 7.6 million tons of coal exported by CONSOL Energy in 2008 and 2007, respectively.

Other income consists of interest income, gain or loss on the disposition of assets, equity in earnings of affiliates, service income, royalty income, derivative gains and losses, rental income and miscellaneous income.

	2008	2007	Dollar Variance	Percentage Change
Gain on sale of assets	$ 23	$ 112	$ (89)	(79.5)%
Interest income	2	13	(11)	(84.6)%
Litigation settlement	1	5	(4)	(80.0)%
Equity in earnings of affiliates	11	7	4	57.1%
Railroad spur income	4	1	3	300.0%
Proceeds from relinquishment of mining rights	6		6	100.0%
Royalty income	21	14	7	50.0%
Contract towing	11	3	8	266.7%
Business interruption proceeds	50	10	40	400.0%
Other miscellaneous	37	31	6	19.4%
Total other income	$ 166	$ 196	$ (30)	(15.3)%

Gain on sale of assets decreased $89 million in the year-to-year comparison primarily due to two transactions that occurred in 2007. In June 2007, CONSOL Energy, through our 83.3% owned subsidiary, CNX Gas, exchanged certain coal assets in Northern Appalachia to Peabody Energy for coalbed methane and gas rights, which resulted in a pretax gain of $50 million. Also, in June 2007, CONSOL Energy, through a subsidiary, sold the rights to certain western Kentucky coal in the Illinois Basin to Alliance Resource Partners, L.P. for $53 million. This transaction also resulted in a pretax gain of approximately $50 million. The 2008 period reflects a sale of an idled facility which included the transfer of the mine closing liabilities to the buyer. This transaction resulted in a pretax gain of approximately $8 million. There was also a $3 million increase in the year-to-year comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Interest income decreased $11 million in the year-to-year comparison due to lower cash balances throughout 2008 compared to 2007. Lower cash balances were primarily the result of the purchase price paid for the June 2008 acquisition of the remaining interest in Knox Energy, LLC, the July acquisition of several leases and gas wells from KIS Oil & Gas, Inc., the July 31, 2007 acquisition of AMVEST, the June 2007 purchase of certain coalbed methane and gas rights from Peabody Energy and the July 2007 Buchanan Mine incident.

A litigation settlement with a coal customer in 2007 resulted in $5 million of income. A litigation settlement with a royalty holder resulted in $1 million of income in 2008.

Equity in earnings of affiliates increased $4 million related to our interest in a specialty contracting company, our interest in a real estate development company and our interest in a coal mining company. These increases were offset, in part, by the June 2008 acquisition of our remaining interest in Knox Energy, LLC.

Income related to a railroad spur acquired with the July 2007 acquisition of AMVEST increased $3 million. This income was due to reimbursements from the rail carrier for maintenance completed on the spur during the year. The income is offset in its entirety with the related expenses reflected in cost of goods sold and other charges.

In 2008, approximately $6 million was received from a third party in order for CONSOL Energy to relinquish the mining of certain in-place coal reserves.

Royalty income increased $7 million in the year-to-year comparison due to production of CONSOL Energy coal by a third-party commencing in August 2007. Royalties have also increased due to the higher sales price of coal sold throughout 2008 compared to 2007.

The $8 million increase in contract towing services represents river towing services for third-parties which CONSOL Energy now provides. These services were minimal in 2007.

In 2008, CONSOL Energy received $50 million as final settlement of the insurance claim related to the July 2007 Buchanan Mine incident, which idled the mine from July 2007 to mid-March 2008. The $50 million represents business interruption coverage which was recognized in other income; the coal segment recognized $42 million and the gas segment recognized $8 million. CONSOL Energy had received $10 million of business interruption proceeds related to this incident in 2007; the coal segment recognized $8 million and the gas segment recognized $2 million. In 2007, $15 million was also received from the insurance carrier for reimbursement of fire brigade costs. This was recognized as a reduction of cost of goods sold and other charges as discussed below. The final settlement brought the total amount recovered from insurance carriers to $75 million, the maximum allowed per covered event. All proceeds from this insurance claim have been received.

Other miscellaneous income increased $6 million in the year-to-year comparison due to various miscellaneous transactions that occurred throughout both years, none of which were individually material.

Costs

Cost of goods sold and other charges increased due to the following:

	2008	2007	Dollar Variance	Percentage Change
Cost of Goods Sold and Other Charges				
Produced Coal	$ 2,031	$ 1,685	$ 346	20.5%
Purchased Coal	124	52	72	138.5%
Produced Gas	189	129	60	46.5%
Industrial Supplies	186	141	45	31.9%
Closed and Idle Mines	78	105	(27)	(25.7)%
Other	235	239	(4)	(1.7)%
Total Sales Outside	2,843	2,351	492	20.9%
Gas Royalty Interest	74	40	34	85.0%
Purchased Gas	8	7	1	14.3%
Total Cost of Goods Sold	$ 2,925	$ 2,398	$ 527	22.0%

Increased cost of goods sold and other charges for company-produced coal was due mainly to a higher average unit cost per ton sold, offset slightly by lower sales volumes.

	2008	2007	Variance	Percentage Change
Produced Tons Sold (in millions)	64.3	64.8	(0.5)	(0.8)%
Average Cost of Goods Sold and Other Charges Per Ton	$ 31.57	$ 25.99	$ 5.58	21.5%

Average cost of goods sold and other charges increased in the year-to-year comparison primarily due to an increase in average unit costs related to the following items.

Supply and maintenance costs have increased $2.77 per ton sold due to the following items:

The increase in supply and maintenance costs reflects the change in the mix of sales tons in 2008 compared to 2007. Production tons from the Northern Appalachian underground mines decreased, while production from the Central Appalachian mines increased. This was primarily due to the July 31, 2007 acquisition of AMVEST and to the Buchanan Mine being idled for half of 2007.

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The installation of higher grade seals and a higher number of seals being built in 2008 contributed to the increase in supply cost. The Mine Health and Safety Administration now requires higher strength seals to be constructed in order to isolate old, abandoned areas or previously sealed areas of the mine. At several locations, the installed seals are also required to be stronger. The increase in strength of seals was required to better protect the active sections of the underground mines from explosions, fires, or other situations that may occur within the sealed areas. The installation of higher strength seals and a higher number of seals being completed contributed to the increase in supply costs.

Higher roof control costs are attributable to higher usage of products used in the mining process due to mining conditions and additional development work. Development work by continuous mining machines requires more roof support products than are used in the area of the mine where extraction is done using a longwall mining system. Roof control costs have also increased due to higher usage of pumpable cribs which are more expensive per unit than the standard wooden crib support. The pumpable crib is a canvas cylinder hung from the roof and extending to the floor into which concrete is pumped. Because the pumpable crib allows concrete to be pumped to the roof level, it eliminates the need to use wood shims to tighten the concrete to the roof. The pumpable crib is quicker to install, enhances safety due to the customized fit and minimizes the use of combustible products at underground locations. Also, roof control costs have increased due to approximately a 9% inflation rate related to roof control products.

Gas well plugging/drilling costs related to the mining process have increased in 2008 compared to 2007. Gas well plugging expenses are related to plugging abandoned gas wells which CONSOL Energy does not own that are in front of the underground mining process. These wells have to be plugged in accordance with current safety regulations in order to mine through. CONSOL Energy has plugged more wells in 2008 than in 2007, which has contributed to increased supply costs. Gas well drilling ahead of mining, vents the gas from the coal seam which then allows for the longwall process to extract coal from a ventilated seam. CONSOL Energy drilled more wells ahead of mining in 2008 than in 2007 primarily due to Buchanan Mine being idled for half of 2007, as previously discussed.

Higher fuel and explosive costs are due to the general increase of these commodities in the year-to-year comparison. The AMVEST surface locations were acquired on July 31, 2007. These surface locations are a large consumer of these products.

Higher equipment maintenance costs are also attributable to the acquisition of AMVEST on July 31, 2007.

These increases in supply costs were offset, in part, by expenses for self contained self rescuers which were purchased in 2007 in compliance with the Miner Act. There were fewer self-contained self rescuers purchased in 2008.

Labor costs have increased $1.14 per ton sold due to the effects of wage increases at the union and non-union mines from labor contracts which began in 2007. These contracts call for specified hourly wage increases in each year of the contract. Labor also increased due to a higher number of employees in 2008 compared to 2007. This was somewhat due to the utilization of new work schedules requiring more manpower and operations trainees.

Other postemployment benefit costs have increased $0.49 per ton sold primarily due to a change in the discount rate used to calculate the net periodic benefit costs. The weighted average discount rate for 2008 was 6.63% and was 6.00% in 2007.

Combined Fund costs have increased $0.33 per ton sold due to the 2007 settlement with the Fund. In March 2007, CONSOL Energy entered into a settlement agreement with the Combined Fund that resolved all previous issues relating to the calculation of the payments. The total income, including interest, as a result of this settlement was approximately $33.4 million, of which approximately $28.1 million impacted cost of goods sold and other charges for produced coal.

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Health & Retirement costs have increased $0.25 per ton sold due to additional contributions required to be made into employee benefit funds in 2008 compared to 2007 as a result of the five-year labor agreement with the United Mine Workers of America (UMWA) that commenced January 1, 2007. The contribution increase over 2007 was $1.27 per UMWA hour worked.

In-transit costs have increased $0.25 per ton sold. In-transit costs are costs to move coal from the point of extraction to the preparation plant in order for the coal to be processed for sale. These costs have increased due primarily to increased trucking expenses related to higher fuel costs as well as several locations operating in the current year that did not operate in 2007.

Various other costs have increased $0.35 per ton sold due to various items that have occurred throughout both periods, none of which individually increased or decreased costs per ton sold.

Purchased coal cost of goods sold consists of costs from processing purchased coal in our preparation plants for blending purposes to meet customer coal specifications, coal purchased and sold directly to customers and costs for processing third-party coal in our preparation plants. The increase of $72 million in purchased coal cost of goods sold and other charges in 2008 was primarily due to higher volumes purchased.

Gas cost of goods sold and other charges increased due primarily to a 32.6% increase in volumes of produced gas sold and an 11.1% increase in unit costs of goods sold and other charges.

	2008	2007	Variance	Percentage Change
Produced Gas Sales Volumes (in billion cubic feet)	75.7	57.1	18.6	32.6%
Average Cost Per thousand cubic feet	$ 2.50	$ 2.25	$ 0.25	11.1%

Average cost of goods sold and other charges per unit sold increased in the current year as a result of the following items:

Fuel and power increased $0.08 per thousand cubic feet for both lifting and gathering combined. This increase was primarily due to additional compressors being placed in service along the existing gathering systems in order to flow gas more efficiently.

Well closing costs increased $0.05 per thousand cubic feet in the year-to-year comparison. Well closing liabilities were adjusted in 2007 to reflect longer well lives than were previously estimated. This adjustment resulted in a reduction to expense. The adjustments to well closing liabilities were insignificant in 2008.

Water disposal costs have increased $0.05 per thousand cubic feet due to additional volumes of water produced by CNX Gas wells in 2008 compared to 2007.

Repairs and maintenance costs have increased $0.02 per thousand cubic feet due to higher material costs and higher contract labor costs.

Compression expenses increased $0.03 per thousand cubic feet due to the additional compressors discussed above.

Various other costs have also increased by $0.02 per thousand cubic feet for various items which occurred throughout both years, none of which were individually material.

Industrial supplies cost of goods sold increased $45 million primarily due to the July 2007 acquisition of Piping & Equipment, Inc. The increase was also related to additional volumes of goods sold and higher costs of good sold throughout 2008.

Closed and idle mine cost of goods sold decreased approximately $27 million in 2008 compared to 2007. The decrease was primarily due to $16 million of lower cost of goods sold and other charges at Shoemaker Mine. Shoemaker resumed longwall production in May 2008, but was idled throughout all of 2007. The decrease was

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also related to updated engineering surveys related to mine closing, perpetual care water treatment and reclamation liabilities for closed and idled locations resulting in $23 million of expense in 2008 compared to $33 million of expense in 2007. The higher 2007 survey adjustments related primarily to perpetual water treatment changes in estimates of water flows and increased hydrated lime costs. Closed and idle mine cost of goods sold and other charges also increased $1 million due to various other charges which occurred throughout both periods, none of which were individually significant.

Other cost of goods sold decreased due to the following items:

	2008	2007	Dollar Variance	Percentage Change
Buchanan roof collapse	$ 17	$ 95	$ (78)	(82.1)%
Contract settlement		6	(6)	(100.0)%
Incentive compensation	33	35	(2)	(5.7)%
Ward superfund site	7	5	2	40.0%
Accounts receivable securitization	6	3	3	100.0%
Railroad spur expenses	4	1	3	300.0%
Asset impairment	6		6	100.0%
Stock-based compensation	34	24	10	41.7%
Profit splits	15		15	100.0%
Sales contract buy-outs	19		19	100.0%
Terminal/River operations	81	58	23	39.7%
Miscellaneous	13	12	1	8.3%
Total of the Cost of Goods Sold and Other Charges	$ 235	$ 239	$ (4)	(1.7)%

In July 2007, production at the Buchanan Mine was suspended after several roof falls in previously mined areas damaged some of the ventilation controls inside the mine, requiring a general evacuation of the mine. In 2008, we have incurred approximately $17 million of cost of goods sold and other charges related to the Buchanan Mine event compared to $95 million in the prior year. The 2007 expense figure is net of $15 million related to insurance proceeds received as reimbursement for costs incurred under the policy. The mine resumed longwall production on March 17, 2008.

In 2007, CONSOL Energy agreed to a $6 million settlement for a contract violation with a customer.

The incentive compensation program is designed to increase compensation to eligible employees when CONSOL Energy reaches predetermined earnings targets and the employees reach predetermined performance targets. Incentive compensation expense decreased $2 million due to the level of earnings in comparison to the predetermined performance target in the year-to-year comparison.

The year ended December 31, 2008 includes expense of $7 million related to the Ward Transformer superfund site. In 2008, revised estimates of total costs related to this site were received. The revised estimates indicate an increase in costs to remediate the site. The year ended December 31, 2007 includes $5 million of expense related to this site. See Note 25 Commitments and Contingencies of Item 8, of the Consolidated Financial Statements for more details.

Accounts receivable securitization fees increased $3 million in the year-to-year comparison. Higher amounts have been drawn under this program throughout 2008 compared to 2007.

Expenses increased $3 million in 2008 related to a railroad spur acquired with the July 2007 acquisition of AMVEST. The increase was related to maintenance completed on the spur during the year. These expenses are offset with the related income reflected in other income.

Asset impairment expenses of $6 million were recognized in 2008 primarily related to loans made to, and options to purchase shares of common stock, with a startup company whose efforts are to commercialize

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technology to burn waste coal with near zero emissions to generate power. Due mainly to the downturn in the economy, it is not probable that the company can repay these loans, or that the company will complete a public offering. Therefore, the asset values have been written down.

Stock-based compensation expense increased $10 million primarily as a result of additional awards granted to CONSOL Energy and CNX Gas employees in 2008. In addition, stock-based compensation expense increased due to changes in expected value of the cash payout related to the performance share units of CNX Gas.

Cost of goods sold and other charges includes $15 million in 2008 related to contracts with certain customers which were unable to take delivery of previously contracted coal tonnage. These customers have agreed to allow CONSOL Energy to sell the released tonnage, but require CONSOL Energy to split the incremental sales price over the original contract sales price evenly with them. The $15 million represents the additional sales price received for the tonnage sold that is owed to the original customer.

In 2008, CONSOL Energy agreed to buy-out sales contracts with several customers in order to release tons committed under lower priced contracts for sale to other customers at higher prices which resulted in $19 million of expense. No such agreements were made in 2007.

Terminal/River operation charges have increased $23 million in the year-to-year comparison due to increased fuel charges resulting from higher fuel prices and increased operating hours. Costs also have increased due to the acquisition of Tri-River Fleeting on October 3, 2007, as well as higher thru-put volumes in 2008.

Miscellaneous cost of goods sold and other charges increased $1 million due to various transactions throughout both periods, none of which were individually material.

	2008	2007	Variance	Percentage Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	8.5	7.2	1.3	18.1%
Average Cost Per thousand cubic feet	$ 8.69	$ 5.52	$ 3.17	57.4%

Gas royalty interest costs represent the expenses related to the portion of production belonging to royalty interest owners sold by CNX Gas on their behalf. The increase in volumes and price relates to the volatility and contractual differences among leases, as well as the mix of average and index prices used in calculating royalties.

	2008	2007	Variance	Percentage Change
Purchased Sales Volumes (in billion cubic feet)	1.0	1.1	(0.1)	(9.1)%
Average Cost Per thousand cubic feet	$ 8.13	$ 6.66	$ 1.47	22.1%

Purchased gas costs represent volumes of gas purchased from third-party producers, less our gathering and marketing fees, that we sell at market prices. Purchased gas volumes also include the impact of pipeline imbalances. The increase in cost of goods sold and other charges related to purchased gas represents overall price increases and contractual differences among customers in the year-to-year comparison.

Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e., rail, barge, truck, etc.) used for the customers to which CONSOL Energy contractually provides transportation services. Freight expense is the amount billed to customers for transportation costs incurred. Freight expense has increased in 2008 due primarily to freight associated with AMVEST, which was acquired on July 31, 2007. Freight expense has also increased due to higher freight rates being charged for exported tons. These increases in freight expense were offset, in part, by lower export tons shipped in 2008 compared to 2007. There were 7.0 million tons and 7.6 million tons of coal exported by CONSOL Energy in 2008 and 2007, respectively.

	2008	2007	Dollar Variance	Percentage Change
Freight expense	$ 217	$ 187	$ 30	16.0%

Selling, general and administrative costs have increased due to the following items:

	2008	2007	Dollar Variance	Percentage Change
Wages, salaries and related benefits	$ 61	$ 52	$ 9	17.3%
Association/charitable contributions	12	6	6	100.0%
Advertising and promotion	6	4	2	50.0%
Professional, consulting and other purchased services	27	29	(2)	(6.9)%
Other	19	18	1	5.6%
Total Selling, General and Administrative	$ 125	$ 109	$ 16	14.7%

Wages, salaries and related benefits increased $9 million in the year-to-year comparison due to additional staffing at our CNX Gas subsidiary, additional administrative staffing acquired in the July 2007 Piping & Equipment acquisition and various other increases in support staff throughout CONSOL Energy.

Association assessments have increased $6 million in the year-to-year comparison due primarily to CONSOL Energy s participation in an industry organization which has launched a program related to the promotion of coal as an energy solution. CONSOL Energy did not participate in this organization in 2007. Also, CONSOL Energy participates in various associations and contributes to various charities in an effort to support the professions and the communities in which we do business. The level of funding made to these organizations varies from year-to-year.

Advertising and promotion expenses increased $2 million in 2008 due to various additional advertising and promotion agreements entered into throughout the current year.

Costs of professional, consulting and other purchased services decreased $2 million due to various administrative projects throughout both years, none of which are individually material.

Other selling, general and administrative costs increased $1 million due to various transactions that have occurred throughout both years, none of which are individually material.

Depreciation, depletion and amortization increased due to the following items:

	2008	2007	Dollar Variance	Percentage Change
Coal	$ 299	$ 258	$ 41	15.9%
Gas:				
Production	50	31	19	61.3%
Gathering	20	18	2	11.1%
Total Gas	70	49	21	42.9%
Other	21	18	3	16.7%
Total Depreciation, Depletion and Amortization	$ 390	$ 325	$ 65	20.0%

The increase in coal depreciation, depletion and amortization was primarily attributable to additional expense related to the assets purchased in the July 2007 acquisition of AMVEST. The increase was also attributable to assets placed in service after December 31, 2007.

The increase in gas production related depreciation, depletion and amortization was primarily due to higher volumes combined with an increase in the units of production rates in the year-to-year comparison. These rates increased due to the higher proportion of capital assets placed in service versus the proportion of proved developed reserve additions. These rates are generally calculated using the net book value of assets at the end of the previous year divided by either proved or proved developed reserves.

Gathering depreciation, depletion and amortization is recorded using the straight-line method and increased due to additional assets placed in service after December 31, 2007.

Other depreciation increased $3 million due to various items placed in service after December 31, 2007, none of which were individually material.

Interest expense increased in 2008 compared to 2007 due to the following items:

	2008	2007	Dollar Variance	Percentage Change
Revolver	$ 11	$ 5	$ 6	120.0%
Interest on unrecognized tax benefits	2	3	(1)	(33.3)%
Capitalized lease	6	7	(1)	(14.3)%
Long-term secured notes	27	28	(1)	(3.6)%
Other	(10)	(12)	2	(16.7)%
Total Interest Expense	$ 36	$ 31	$ 5	16.1%

Revolver interest expense increased $6 million due to the amounts drawn by CONSOL Energy and CNX Gas on the credit facility throughout 2008. There were no amounts drawn until August 2007 on this facility by CONSOL Energy. CNX Gas had no amounts drawn throughout all of 2007. These increases were offset, in part, by lower interest rates in the year-to-year comparison.

Interest on uncertain tax benefits decreased $1 million due primarily to the settlement of various uncertain tax positions due to receipt of the audit report related to the years 2004-2005.

Interest on capital leases decreased $1 million due to the planned payments made on these leases after December 31, 2007.

Interest on long-term secured notes decreased $1 million due to the planned June 2007 principal payment on our $45 million secured note.

Other interest increased $2 million due primarily to lower amounts of interest capitalized in 2008 compared to 2007. Capitalized interest was lower in 2008 because capital expenditures which qualify for interest capitalization were lower. These lower expenditures were primarily related to the Robinson Run overland belt which was placed in service in September 30, 2007.

On October 3, 2008 the Emergency Economic Stabilization Act of 2008 (the EESA Act) was signed into law. The EESA Act contains a section that authorizes certain coal producers and exporters who have filed a Black Lung Excise Tax (BLET) return on or after October 1, 1990, to request a refund of the BLET paid on export sales. The EESA Act requires that the U.S. Treasury refund a coal producer or exporter an amount equal to the BLET erroneously paid on export sales in prior years along with interest computed at the statutory rates applicable to overpayments. CONSOL Energy filed timely claims for refunds under the EESA Act of the BLET with the Internal Revenue Service in the amount of approximately $27 million. In addition, the estimated interest related to the BLET refunds expected to be received is approximately $32 million. In relation to this receivable, CONSOL Energy also recognized approximately $3 million of expense that will be owed to third parties upon collection of the refunds. The year ended December 31, 2007 included a $24 million charge related to the reversal of the receivable that had been recognized in previous quarters related to the BLET refund. The Federal Circuit court had ruled that the damage claim for BLET paid for the period 1991-1993 be repaid. The Government appealed a similar case to the U.S. Supreme Court. On December 3, 2007 the United States Supreme Court granted the Government s appeal to hear the case. The Supreme Court s appeal of the petition made collection of the refund no longer highly probable because of the adverse ruling by the Supreme Court during 2007 under the statute on which our claim for this period was based. Accordingly, CONSOL Energy reversed the BLET receivable it had previously recognized.

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Taxes other than income increased primarily due to the following items:

	2008	2007	Dollar Variance	Percentage Change
Production taxes:				
Coal	$ 168	$ 150	$ 18	12.0%
Gas	20	13	7	53.8%
Total Production Taxes	188	163	25	15.3%
Other taxes:				
Coal	84	79	5	6.3%
Gas	7	5	2	40.0%
Other	11	12	(1)	(8.3)%
Total Other Taxes	102	96	6	6.3%
Total Taxes Other Than Income	$ 290	$ 259	$ 31	12.0%

Coal production taxes increased $18 million due to higher severance taxes and reclamation fee taxes attributable to the increase in average sales price for produced coal. Coal production taxes also increased due to higher tons produced in 2008 than 2007.

Gas production taxes increased $7 million due to higher severance taxes attributable to higher average sales prices for gas and higher gas sales volumes.

The $5 million increase in other coal taxes is primarily due to higher payroll related taxes and higher property taxes. Higher payroll related taxes were the result of additional employees in 2008 and higher wages paid as discussed in the cost of goods sold and other cost section. Higher property taxes were related to additional properties acquired in the July 31, 2007 AMVEST acquisition, as previously disclosed.

Other gas taxes have increased $2 million primarily related to payroll taxes and capital stock & franchise taxes due to the on-going growth of the company.

Other taxes decreased $1 million due to various transactions that occurred throughout both years, none of which were individually material.

Income Taxes

	2008	2007	Variance	Percentage Change
Earnings Before Income Taxes	$ 725	$ 429	$ 296	69.0%
Tax Expense	$ 240	$ 136	$ 104	76.5%
Effective Income Tax Rate	33.1%	31.7%	1.4%	

CONSOL Energy s effective tax rate is sensitive to changes in the relationship between pre-tax earnings and percentage depletion. The proportion of coal pre-tax earnings and gas pre-tax earnings also impacts the benefit of percentage depletion on the effective tax rate. See Note 6 Income Taxes in Item 8, Consolidated Financial Statements of this Form 10-K.

Noncontrolling Interest

Noncontrolling interest represents 18.3% of CNX Gas net income which CONSOL Energy did not own through September 30, 2008, 18.0% for October 2008, 16.9% for November 2008 and 16.7% for December 2008. The noncontrolling interest in CNX Gas has been changing due to the share repurchase program that was approved by the CONSOL Energy Board of Directors on October 21, 2008.

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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. Note 1 of the Notes to the Audited Consolidated Financial Statements in this Annual Report on Form 10-K describes the significant accounting policies and methods used in the preparation of the Consolidated Financial Statements. 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

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 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 participant. Any salaried or non-represented hourly employees that were hired or rehired effective January 1, 2007 or later will not become 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, will not be eligible to receive retiree benefits. In lieu of these benefits, these employees will receive a defined contribution benefit of $1 per each hour worked.

After our review, 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 are used by our independent actuary to estimate the cost and benefit obligations for our retiree health plans. Most assumptions used in 2009 have not differed materially from the prior year actual experience. Expected trend in health care cost assumptions have been changed since the prior year. The initial expected trend in health care costs at this year s measurement date, which was December 31, 2009, was 8.74% compared to a prior year expected 2009 trend in health care cost of 9.6%. In addition, the year the ultimate trend rate is reached was extended from 5.0% in 2015 to 4.50% in 2023. A 1.0% decrease in the health care trend rate would decrease interest and service cost for 2009 by approximately $17.0 million. A 1.0% increase in the health care trend rate would increase the interest and service cost by approximately $19.9 million. The discount rate is also determined each year at the measurement date. The discount rate is estimated by utilizing a corporate yield curve model developed from corporate bond data using only bonds rated Aa by Moody s as of the measurement date. All future post employment benefit expected payments were discounted using a spot rate yield curve as of December 31, 2009. The appropriate discount rate was then selected from resulting discounted cash flows. For the years ended December 31, 2009 and 2008, the discount rate used to calculate the period end liability and the following year s expense was 5.87% and 6.20%, respectively. A 0.25% increase in the discount rate would have decreased 2009 net periodic postretirement benefit costs by approximately $3.8 million. A 0.25% decrease in the discount rate would have increased 2009 net periodic postretirement benefit costs by approximately $3.8 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, 2009 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, 2009, the average remaining life expectancy of our retired UMWA population used to calculate the following year s expense is approximately 13 years.