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

FORM 10-K

(Mark One)

☒ 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 to

Commission File No. 001-07775

MASSEY ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware	95-0740960
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
4 North 4th Street, Richmond, Virginia	23219
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (804) 788-1800

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.625 par value	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 ☒ 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 ☒

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 ☒ No ☐

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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," "non-accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check One):

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

The aggregate market value of the common stock held by non-affiliates of the registrant on June 30, 2009, was $1,670,076,824 based on the last sales price reported that date on the New York Stock Exchange of $19.54 per share. In determining this figure, the Registrant has assumed that all of its directors and executive officers are affiliates. Such assumptions should not be deemed to be conclusive for any other purpose.

Common stock, $0.625 par value ("Common Stock"), outstanding as of February 15, 2010 — 86,545,037 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Part III incorporates certain information by reference from the registrant's definitive proxy statement for the 2010 Annual Meeting of Stockholders, which proxy statement will be filed no later than 120 days after the close of the registrant's fiscal year ended December 31, 2009.

Forward Looking Statements

From time to time, we make certain comments and disclosures in reports, including this report, or through statements made by our officers that may be forward-looking in nature. Examples include statements related to our future outlook, anticipated capital expenditures, projected cash flows and borrowings and sources of funding. We caution readers that forward-looking statements, including disclosures that use words such as “anticipate,” “believe,” “estimate,” “expect,” “goal,” “intend,” “may,” “objective,” “plan,” “project,” “target,” “will” and similar words or statements are subject to certain risks, trends and uncertainties that could cause actual cash flows, results of operations, financial condition, cost reductions, acquisitions, dispositions, financing transactions, operations, expansion, consolidation and other events to differ materially from the expectations expressed or implied in such forward-looking statements. Any forward-looking statements are also subject to a number of assumptions regarding, among other things, future economic, competitive and market conditions. These assumptions are based on facts and conditions, as they exist at the time such statements are made as well as predictions as to future facts and conditions, the accurate prediction of which may be difficult and involve the assessment of circumstances and events beyond our control. We disclaim any intent or obligation to update these forward-looking statements unless required by securities law, and we caution the reader not to rely on them unduly. We have based any forward-looking statements we have made on our current expectations and assumptions about future events and circumstances that are subject to risks, uncertainties and contingencies that could cause results to differ materially from those discussed in the forward-looking statements, including, but not limited to:

(i) our cash flows, results of operation or financial condition;
(ii) the successful completion of acquisition, disposition or financing transactions and the effect thereof on our business;
(iii) governmental policies, laws, regulatory actions and court decisions affecting the coal industry or our customers’ coal usage;
(iv) legal and administrative proceedings, settlements, investigations and claims and the availability of insurance coverage related thereto;
(v) inherent risks of coal mining beyond our control, including weather and geologic conditions or catastrophic weather-related damage;
(vi) inherent complexities make it more difficult and costly to mine in Central Appalachia than in other parts of the United States;
(vii) our production capabilities to meet market expectations and customer requirements;
(viii) our ability to obtain coal from brokerage sources or contract miners in accordance with their contracts;
(ix) our ability to obtain and renew permits necessary for our existing and planned operations in a timely manner;
(x) the cost and availability of transportation for our produced coal;
(xi) our ability to expand our mining capacity;
(xii) our ability to manage production costs, including labor costs;
(xiii) adjustments made in price, volume or terms to existing coal supply agreements;
(xiv) the worldwide market demand for coal, electricity and steel;
(xv) environmental concerns related to coal mining and combustion and the cost and perceived benefits of alternative sources of energy such as natural gas and nuclear energy;
(xvi) competition among coal and other energy producers, in the United States and internationally;
(xvii) our ability to timely obtain necessary supplies and equipment;
(xviii) our reliance upon and relationships with our customers and suppliers;
(xix) the creditworthiness of our customers and suppliers;
(xx) our ability to attract, train and retain a skilled workforce to meet replacement or expansion needs;
(xxi) our assumptions and projections concerning economically recoverable coal reserve estimates;
(xxii) our failure to enter into anticipated new contracts;
(xxiii) future economic or capital market conditions;
(xxiv) foreign currency fluctuations;
(xxv) the availability and costs of credit, surety bonds and letters of credit that we require;
(xxvi) the lack of insurance against all potential operating risks;
(xxvii) our assumptions and projections regarding pension and other post-retirement benefit liabilities;
(xxviii) our interpretation and application of accounting literature related to mining specific issues; and
(xxix) the successful implementation of our strategic plans and objectives for future operations and expansion or consolidation.

We are including this cautionary statement in this document 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. Any forward-looking statements should be considered in context with the various disclosures made by us about our businesses, including without limitation the risk factors more specifically described below in Item 1A. Risk Factors of this Annual Report on Form 10-K.

2009 ANNUAL REPORT ON FORM 10-K

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Annual Shareholders Meeting

Our 2010 Annual Meeting of Shareholders will be held at 9:00 a.m. EDT on Tuesday, May 18, 2010 at The Jefferson Hotel, 101 West Franklin Street, Richmond, Virginia 23220.

Part I

Because certain terms used in the coal industry may be unfamiliar to many investors, we have provided a Glossary of Selected Terms beginning on page 21 at the end of Item 1. Business.

Item 1. Business

Business Overview

We are one of the largest coal producers in the United States and we are the largest coal company in Central Appalachia, our primary region of operation, in terms of tons produced and total coal reserves in 2009.

We produce, process and sell bituminous coal of various steam and metallurgical grades, primarily of a low sulfur content, through our 23 processing and shipping centers (“Resource Groups”), many of which receive coal from multiple mines. At January 31, 2010, we operated 56 mines, including 42 underground mines (two of which employ both room and pillar and longwall mining) and 14 surface mines (with 12 highwall miners in operation) in West Virginia, Kentucky and Virginia. The number of mines that we operate may vary from time to time depending on a number of factors, including the existing demand for and price of coal, exhaustion of economically recoverable reserves and availability of experienced labor.

Customers for our steam coal product include primarily electric power utility companies who use our coal as fuel for their steam-powered generators. Customers for our metallurgical coal include primarily steel producers who use our coal to produce coke, which is in turn used as a raw material in the steel manufacturing process.

A.T. Massey was originally incorporated in Richmond, Virginia in 1920 as a coal brokering business. In the late 1940s, A.T. Massey expanded its business to include coal mining and processing. In 1974, St. Joe Minerals acquired a majority interest in A.T. Massey. In 1981, St. Joe Minerals was acquired by Fluor Corporation. A.T. Massey was wholly owned by Fluor Corporation from 1987 until November 30, 2000. On November 30, 2000, we completed a reverse spin-off (the “Spin-Off”) which separated Fluor Corporation into two entities: the “new” Fluor Corporation (“New Fluor”) and Fluor Corporation which retained our coal-related businesses and was subsequently renamed Massey Energy Company. Massey Energy Company has been a separate, publicly traded company since December 1, 2000.

Industry Overview

Coal accounted for 25% of the energy consumed (excluding certain alternative fuels including wind, geothermal and solar power generators) by the United States and 29% of energy consumed globally in 2008, according to the BP Statistical Review of World Energy (“BP”). In 2008, coal was the fuel source of 49% of the electricity generated nationwide, as reported by the Energy Information Administration (“EIA”), a statistical agency of the United States Department of Energy.

According to BP, in 2008, the United States was the second largest coal producer in the world, exceeded only by China. Other leading coal producers include Australia, India, South Africa, the Russian Federation and Indonesia. According to BP, the United States has the largest coal reserves in the world, with proved reserves totaling 238 billion tons. The Russian Federation ranks second in proved coal reserves with 157 billion tons, followed by China with 115 billion tons, according to BP. The United States has more than 200 years of coal reserves at current production rates.

United States coal production has more than doubled over the last 40 years. In 2009, total United States coal production, as estimated by EIA, was 1.1 billion tons. The primary producing regions by tons were as follows:

Region	% of Total
Powder River Basin	46%
Central Appalachia	19%
Northern Appalachia	12%
West (other than Powder River Basin)	11%
Midwest	10%
All other	2%
Total	100%

The EIA estimated that approximately 69% of United States coal was produced by surface mining methods in 2008. The remaining 31% was produced by underground mining methods, which include room and pillar mining and longwall mining (more fully described in Item 1. Business, under the heading “Mining Methods”).

Coal is used in the United States by utilities to generate electricity, by steel companies to make steel products, and by a variety of industrial users to produce heat and to power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. Significant quantities of coal are also exported from both East and Gulf Coast terminals. The breakdown of United States coal consumption for the first ten months of 2009 as estimated by EIA is as follows:

End Use	% of Total
Electric Power	94%
Other Industrial	4%
Coke	2%
Residential and Commercial	<1%
Total	100%

Coal has long been favored as an electricity generating fuel because of its basic economic advantage. The largest cost component in electricity generation is fuel. This fuel cost is typically lower for coal than competing fuels such as oil and natural gas on a Btu-comparable basis. The EIA estimates the average cost of various fossil fuels for generating electricity in the first 10 months of 2009 was as follows:

Electricity Generation Source	Average Cost per million BTU
Petroleum Liquids	$9.92
Natural Gas	$4.65
Coal	$2.22
Petroleum Coke	$1.59

There are factors other than fuel cost that influence each utility’s choice of electricity generation mode, including facility construction cost, access to fuel transportation infrastructure, environmental restrictions, and other factors. The breakdown of United States electricity generation by fuel source in the first 10 months of 2009, as estimated by EIA, is as follows:

Electricity Generation Source	% of Total Electricity Generation
Coal	44%
Natural Gas	24%
Nuclear	20%
Hydroelectric	7%
Oil and other (solar, wind, etc.)	5%
Total	100%

Demand for electricity has historically been driven by United States economic growth but it can fluctuate from year to year depending on weather patterns. In the first 10 months of 2009, electricity consumption in the United States decreased 4.4% from the same period in 2008, but the average growth rate in the past decade was approximately 1.3% per year according to EIA estimates. Because coal-fired generation is used in most cases to meet base load requirements, coal consumption has generally grown at the pace of electricity demand growth.

According to the World Coal Institute (“WCI”), in 2008, the United States ranked fourth among worldwide exporters of coal. Australia was the largest exporter, with other major exporters including Indonesia, the Russian Federation, Columbia, South Africa and China. According to Energy Ventures Analysis, Inc. ("EVA"), United States exports decreased by 28% from 2008 to 2009. The usage breakdown for 2009 United States coal exports of 59 million tons was 39% for electricity generation and 61% for steel production. In 2009, United States coal exports were shipped to more than 40 countries. The largest purchaser of United States exported utility coal in 2009 continued to be Canada, which took 8.2 million tons or 36% of total utility coal exports. This was down 57% compared to the 19.1 million tons exported to Canada in 2008. Overall steam coal exports decreased 41% in 2009 compared to 2008. The largest purchaser of United States exported metallurgical coal was Brazil, which imported approximately 8.1 million tons from the United States, or 22% of total United States metallurgical coal exports. In total, metallurgical coal exports decreased 16% in 2009, compared to 2008.

Depending on the relative strength of the United States dollar versus currencies in other coal producing regions of the world, United States producers may export more or less coal into foreign countries as they compete on price with other foreign coal producing sources. Likewise, the domestic coal market may be impacted due to the relative strength of the United States dollar to other currencies, as foreign sources could be cost-advantaged based on a coal producing region's relative currency position.

During the past ten years, the global marketplace for coal has experienced swings in the demand/supply balance. In periods of supply shortfall, as occurred from 2003 to early 2006 and again in late 2007 through late 2008, the prices for coal reached record highs in the United States. The increased worldwide demand was primarily driven by higher prices for oil and natural gas and economic expansion, particularly in China, India and elsewhere in Asia. At the same time, infrastructure and regulatory limitations in China contributed to a tightening of worldwide coal supply, affecting global prices of coal. The growth in China and India caused an increase in worldwide demand for raw materials and a disruption of expected coal exports from China to Japan, Korea and other countries. Since mid-2008, the United States and world economies have been in an economic recession and financial credit crisis, reducing the demand for coal.

Metallurgical grade coal is distinguished by special quality characteristics that include high carbon content, volatile matter, low expansion pressure, low sulfur content, and various other chemical attributes. High vol met coal is also high in heat content (as measured in Btus), and therefore is desirable to utilities as fuel for electricity generation. Consequently, high vol met coal producers have the ongoing opportunity to select the market that provides maximum revenue and profitability. The premium price offered by steel makers for the metallurgical quality attributes is typically higher than the price offered by utility coal buyers that value only the heat content. The primary concentration of United States metallurgical coal reserves is located in the Central Appalachian region. EVA estimates that the Central Appalachian region supplied 88% of domestic metallurgical coal and 70% of United States exported metallurgical coal during 2008.

For utility coal buyers, the primary goal is to maximize heat content, with other specifications like ash content, sulfur content, and size varying considerably among different customers. Low sulfur coals, such as those produced in the western United States and in Central Appalachia, generally demand a higher price due to restrictions on sulfur emissions imposed by the Federal Clean Air Act, as amended, and implementing regulations ("Clean Air Act") and the volatility in sulfur dioxide ("SO_2") allowance prices that occurred in recent years when the demand for all specifications of coal increased. SO_2 allowances permit utilities to emit a higher level of SO_2 than otherwise required under the Clean Air Act regulations. The demand and premium price for low sulfur coal is expected to diminish as more utilities install scrubbers at their coal-fired plants.

Coal shipped for North American consumption is typically sold at the mine loading facility with transportation costs being borne by the purchaser. Offshore export shipments are normally sold at the ship-loading terminal, with the purchaser paying the ocean freight. According to the National Mining Association ("NMA"), approximately two-thirds of United States coal shipments in recent years were transported via railroads. Final delivery to consumers often involves more than one transportation mode. A significant portion of United States production is delivered to customers via barges on the inland waterway system and ships loaded at Great Lakes ports.

Neither we nor any of our subsidiaries are affiliated with or have any investment in BP, EIA, EVA or WCI. We are a member of the NMA.

Mining Methods

We produce coal using four distinct mining methods: underground room and pillar, underground longwall, surface and highwall mining, which are explained as follows:

In the underground room and pillar method of mining, continuous miners cut three to nine entries into the coal bed and connect them by driving crosscuts, leaving a series of rectangular pillars, or columns of coal, to help support the mine roof and control the flow of air. Generally openings are driven 20 feet wide and the pillars are 40 to 100 feet wide. As mining advances, a grid-like pattern of entries and pillars is formed. When mining advances to the end of a panel, retreat mining may begin. In retreat mining, as much coal as is feasible is mined from the pillars that were created in advancing the panel, allowing the roof to fall upon retreat. When retreat mining is completed to the mouth of the panel, the mined panel is abandoned.

In longwall mining (which is a type of underground mining), a shearer (cutting head) moves back and forth across a panel of coal typically about 1,000 feet in width, cutting a slice approximately 3.5 feet deep. The cut coal falls onto a flexible conveyor for removal. Longwall mining is performed under hydraulic roof supports (shields) that are advanced as the seam is cut. The roof in the mined out areas falls as the shields advance.

Surface mining is used to extract coal deposits found close to the surface. This method involves removal of overburden (earth and rock covering coal) with heavy earth moving equipment, including large shovels and draglines, and explosives, followed by extraction of coal from coal seams. After extraction of coal, disturbed parcels of land are reclaimed by replacing overburden and reestablishing vegetation and plant life.

Highwall mining is used in connection with surface mining. A highwall mining system consists of a remotely controlled continuous miner, which extracts coal and conveys it via augers or belt conveyors to the portal. The cut is typically a rectangular, horizontal opening in the highwall (the unexcavated face of exposed overburden and coal in a surface mine) 11-feet wide and reaching depths of up to 1,000 feet. Multiple, parallel openings are driven into the highwall, separated by narrow pillars that extend the full depth of the hole.

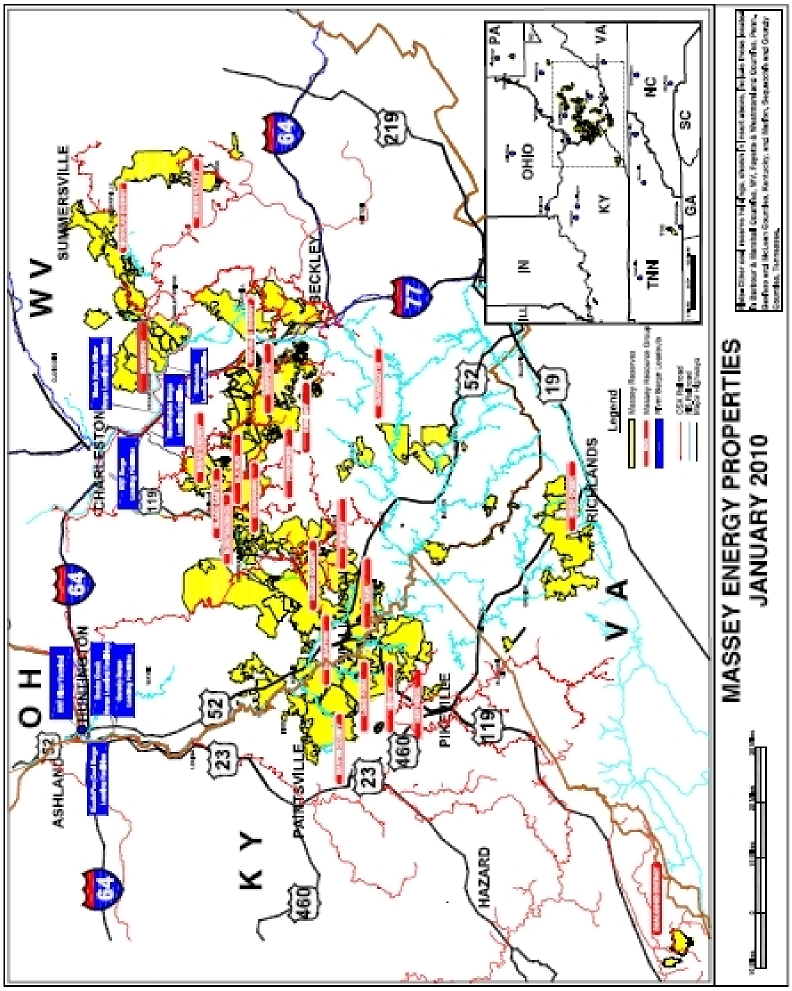
Use of continuous miners in the room and pillar method of underground mining represented approximately 45% of our 2009 coal production. Production from underground longwall mining operations constituted approximately 3% of our 2009 production. Surface mining represented approximately 44% of our 2009 coal production. Highwall mining represented approximately 8% of our 2009 coal production.

Mining Operations

We currently have 23 distinct Resource Groups, including seventeen in West Virginia, five in Kentucky and one in Virginia. These complexes blend, process and ship coal that is produced from one or more mines, with a single complex handling the coal production of as many as ten distinct underground or surface mines. Our mines have been developed at strategic locations in close proximity to our preparation plants and rail shipping facilities.

We currently operate solely in the Central Appalachian region, which is the principal source of low sulfur bituminous coal in the United States, used for power generation, metallurgical coke production and industrial boilers. Central Appalachian coal accounted for 19% of 2009 United States coal production according to EIA.

The following map provides the location of our operations within the Central Appalachian region:



The following table provides key operational information on our Resource Groups in 2009:

Resource Group Name	Location (County)	Active/ Inactive	Mine Type	Active Mine Count (1)	Mining Equipment	Transportation	2009 Production (2)	2009 Shipments (3)	Year Established or Acquired
							(Thousands of Tons)		
West Virgina Resource Groups									
Black Castle	Boone	Active	S	1	HW	truck, barge	2,680	1,843	1987
Delbarton	Mingo	Active	U	1		NS	476	893	1999
Edwight	Raleigh	Active	S	1		CSX	1,482	2,159	2003
Elk Run	Boone	Active	U	5		CSX	2,033	3,292	1978
Endurance	Boone	Inactive				CSX	483	194	2001
Green Valley	Nicholas	Active	U	3		CSX	847	807	1996
Guyandotte	Wyoming	Active	U	1		NS	228	208	2006
Independence	Boone	Active	U	3	LW	CSX	1,490	2,811	1994
Inman	Boone	Active	U	1		CSX	536	-	2008
Logan County	Logan	Active	S/U	2	HW	CSX	3,738	3,233	1998
Mammoth	Kanawha	Active	U	4		barge/NS	1,688	4,465	2004
Marfork	Raleigh	Active	S/U	9	LW/HW	CSX	4,244	3,925	1993
Nicholas Energy	Nicholas	Active	S/U	3	HW	NS	2,211	2,043	1997
Progress	Boone	Active	S	1	HW/DL	CSX	4,954	3,149	1998
Rawl	Mingo	Active	U	2		NS	999	-	1974
Republic Energy	Raleigh	Active	S	2	HW	truck	3,367	260	2004
Stirrat	Logan	Active				CSX	450	1.068	1993
Kentucky Resource Groups									
Coalgood Energy	Harlan	Active	S/U	2	HW	CSX	348	310	2005
Long Fork	Pike	Active				NS	-	1,513	1991
Martin County	Martin	Active	S/U	4	HW	NS	1,691	1,394	1969
New Ridge	Pike	Active				CSX	-	315	1992
Sidney	Pike	Active	S/U	9	HW	NS	3,447	2,219	1984
Virginia Resource Group									
Knox Creek	Tazewell	Active	S/U	2	HW	NS	562	551	1997
Total				56			37,954	36,652	

(1) Active mine count as of January 31, 2010
(2) For purposes of this table, coal production has been allocated to the Resource Group where the coal is mined, rather than the Resource Group where the coal is processed and shipped. Production amounts above represent coal extracted from the ground.
(3) For purposes of this table, coal shipments have been allocated to the Resource Group from where the coal is processed and shipped, rather than the Resource Group where the coal is mined.

S -surface mine
U -underground mine
HW -highwall miners operated in conjunction with surface mines
DL -dragline
NS -Norfolk Southern Railway Company
CSX - CSX Transportation

The following descriptions of the Resource Groups are current as of January 31, 2010:

West Virginia Resource Groups

Black Castle. The Black Castle complex includes a large surface mine, two highwall miners, the Homer III direct-ship loadout, a stoker plant, and the Omar preparation plant. Some of the surface mine coal is trucked to the stoker plant where the coal is crushed and screened. The stoker product is trucked to river docks for barge delivery or trucked directly to customers. A portion of the coal is trucked to the Omar plant, where it is crushed and shipped to customers or, if the coal needs processing, it is belted to the preparation plant at the Independence Resource Group for processing and shipment. The direct-ship facility at the preparation plant can crush 500 tons per hour and the preparation plant can process 800 tons per hour. The Omar preparation plant serves CSX rail system customers with unit train shipments of up to 110 railcars. Coal is also trucked to the Homer III loadout where it is crushed and shipped to customers by rail, trucked to river docks for barge delivery, or trucked directly to customers. The Homer III loadout serves CSX rail system customers with unit train shipments of up to 100 railcars. The Omar preparation plant was not utilized for processing coal in 2009.

Delbarton. The Delbarton complex includes one underground room and pillar mine and a preparation plant. Production from the mine is transported to the Delbarton preparation plant via overland conveyor. The Delbarton preparation plant also processes coal from a surface mine of the Logan County Resource Group. The Delbarton preparation plant can process 600 tons per hour. The clean coal product is shipped to customers via the Norfolk Southern railway in unit trains of up to 110 railcars.

Edwight. The Edwight complex includes a surface mine and the Goals preparation plant. Production from the surface mine is transported via conveyor system to the Goals preparation plant. The Goals preparation plant can process 800 tons per hour. The rail loading facility serves CSX railway customers with unit trains of up to 100 railcars.

Elk Run. The Elk Run complex produces coal from five underground room and pillar mines, which is belted to the Elk Run preparation plant. Additionally, Elk Run processes coal produced by surface mines of the Progress Resource Group and transported via underground conveyor system. The Elk Run preparation plant has a processing capacity of 2,200 tons per hour. Elk Run also operates a 200 ton per hour stoker facility that produces screened, small dimension coal for certain of our industrial customers. Customer shipments are loaded on the CSX rail system in unit trains of up to 150 railcars.

Endurance. The Endurance complex includes an idle surface mine and a direct-ship loadout. When in production, a portion of the production from the surface mine is loaded for shipment to customers at the direct-ship loadout and the remainder is trucked to the preparation plant at the Independence Resource Group for processing.

Green Valley. The Green Valley complex includes three underground room and pillar mines and a preparation plant. The Green Valley preparation plant, which has a processing capacity of 600 tons per hour, receives coal from the mines via trucks. The rail loading facility services customers on the CSX rail system with unit train shipments of up to 75 railcars.

Guyandotte. The Guyandotte complex includes one underground room and pillar mine. The mine belts coal to a third-party preparation plant for washing and shipment to customers via the Norfolk Southern railway system.

Independence. The Independence complex includes the Revolution longwall mine, two underground room and pillar mines and a preparation plant. Production from the underground mines is transported via overland conveyor system to the Independence preparation plant. The surface mine at the Black Castle Resource Group belts coal requiring processing to the Independence preparation plant. The Independence plant has a processing capacity of 2,200 tons per hour. Customers are served via rail shipments on the CSX rail system in unit trains of up to 150 railcars.

Inman. The Inman complex includes one underground room and pillar mine and a preparation plant. Production from the underground mine is transported via overland conveyor system to the preparation plant. The Inman plant has a processing capacity of 800 tons per hour. Coal processed at the preparation plant is trucked to Marfork Resource Group's preparation plant where it is loaded and shipped to customers via the CSX rail system in unit trains of up to 150 railcars.

Logan County. The Logan County complex includes a surface mine, a highwall miner and an underground room and pillar mine. Production from the underground mine is transported via truck to the preparation plant of the Stirrat Resource Group. The surface mine and highwall miner production is transported via truck to the Feats Loadout or the Delbarton Resource Group preparation plant. The Feats Loadout can service customers via the CSX rail system with unit train shipments of up to 80 cars. The Logan County Resource Group preparation plant ("Bandmill preparation plant") was destroyed by fire in August 2009. A new plant is expected to be completed in fall of 2010, at which time the production from the underground room and pillar mine will go to this new plant. Additionally, upon completion of the new plant, three surface mines that are currently idle are expected to be re-started.

Mammoth. The Mammoth complex operates four underground room and pillar mines and a preparation plant. Coal is transported to the preparation plant using a conveyor system. The plant has a 1,200 tons per hour processing facility capacity with barge loading capabilities on the upper Kanawha River and a rail loading facility that services customers on the Norfolk Southern railway with unit trains of up to 130 railcars.

Marfork. The Marfork complex includes seven underground room and pillar mines, a longwall mine, a surface mine, a highwall miner and a preparation plant. Production from the longwall mine and six of the underground mines is belted directly to the Marfork preparation plant while production from the remaining underground mine is belted to Edwight Resource Group's Goals preparation plant. Production from the surface mine and the highwall miner is trucked to either the Marfork preparation plant or the Elk Run Resource Group's preparation plant. The Marfork preparation plant has a capacity of 2,400 tons per hour. Customers are served via the CSX rail system with unit trains of up to 150 railcars.

Nicholas Energy. The Nicholas Energy complex includes one underground room and pillar mine, a surface mine, two highwall miners and a preparation plant. Coal from the underground mine is transported to the preparation plant for processing via conveyor system. Coal from the highwall miners and the portion of surface mined coal requiring processing is transported to the preparation plant using off-road trucks. Coal not requiring processing is transported via off-road trucks to a conveyor system that moves the coal directly to a rail loadout facility. The plant has a processing capacity of 1,200 tons per hour. Coal shipments are loaded into rail cars for delivery via the Norfolk Southern railway in unit trains of up to 140 railcars, or are transported via on-highway trucks to the Mammoth Resource Group's barge loading facility.

Progress. The Progress complex includes the large Twilight MTR surface mine and a highwall miner. A dragline is also utilized at the Twilight MTR surface mine. Production from the Twilight MTR surface mine is transported via underground conveyor to the Elk Run Resource Group for processing and rail shipment.

Rawl. The Rawl complex includes two underground room and pillar mines and a preparation plant. Production from the mines is transported via truck to the preparation plant of the Stirrat Resource Group. The Rawl plant, which was idled in December 2006, has a throughput capacity of 1,450 tons per hour. Customers can be served by the Rawl plant via the Norfolk Southern railway with unit trains of up to 150 railcars.

Republic Energy. The Republic Energy complex consists of two surface mines and a highwall miner. Direct-ship coal is trucked using on-highway trucks to various docks on the Kanawha River for barge delivery to customers and to the Marfork Resource Group for rail delivery to customers. Coal requiring processing is trucked using on-highway trucks to Mammoth Resource Group's preparation plant for processing and barge or train delivery to customers.

Stirrat. The Stirrat complex includes a preparation plant and the Superior loadout. The Superior loadout serves CSX railway customers with unit trains of up to 100 railcars. The Stirrat preparation plant cleans coal from two adjacent underground room and pillar mines of the Rawl Resource Group and one underground room and pillar mine of the Logan County Resource Group. The plant has a rated capacity of 600 tons per hour. Customers are served via the CSX rail system with unit trains of up to 100 railcars.

Kentucky Resource Groups

Coalgood Energy. The Coalgood Energy complex includes one underground room and pillar mine, one surface mine, one highwall miner, a direct-ship loadout and a preparation plant. The coal from the surface mine is trucked off-road to the loadout, which serves CSX railway customers with unit trains of up to 100 railcars. Production from the underground mine and the highwall miner is transported via truck to the preparation plant. The Coalgood Energy preparation plant has a throughput capacity of 800 tons per hour. Coal from this preparation plant is loaded onto trains from the direct-ship loadout.

Long Fork. The Long Fork preparation plant processes coal produced by two underground room and pillar mines of the Sidney Resource Group. All production is transported via conveyor system to the Long Fork preparation plant for processing and shipping to customers. The Long Fork plant has a rated capacity of 1,500 tons per hour. The rail loading facility services customers on the Norfolk Southern railway with unit trains of up to 150 railcars.

Martin County. The Martin County complex includes two underground room and pillar mines, two surface mines, a highwall miner and a preparation plant. Direct-ship coal production from the surface mines is shipped to river docks via truck. Surface mine and highwall miner coal requiring processing and production from the underground mines is transported by conveyor belt or truck to the preparation plant. Martin County's preparation plant has a throughput capacity of 1,500 tons per hour, although the throughput capacity is limited due to decreased impoundment availability. The coal from the preparation plant can be shipped either via the Norfolk Southern railway in unit trains of up to 125 railcars or to river docks via truck.

New Ridge. The New Ridge complex loads clean coal that is transported via truck from the preparation plant of the Sidney Resource Group and coal trucked directly from Sidney's surface mine. The New Ridge preparation plant has a capacity of 800 tons per hour. The preparation plant is currently idle but may be reactivated from time to time during 2010 as needed. All coal is loaded for shipment to customers via the CSX rail system in unit trains of up to 100 railcars.

Sidney. The Sidney complex includes eight underground room and pillar mines, one surface mine, a highwall miner and a preparation plant. Four of the underground mines transport coal via underground conveyor system to the Long Fork Resource Group for processing and shipment, and the remainder of the underground mines transport production via underground conveyor system or truck to Sidney's preparation plant. A portion of the coal from Sidney's preparation plant and coal from the surface mines are trucked to the New Ridge Resource Group for loading into railroad cars. Sidney's preparation plant has a capacity of 1,500 tons per hour. The rail loading facility at the preparation plant serves customers on the Norfolk Southern rail system with unit trains of up to 140 railcars.

Virginia Resource Group

Knox Creek. The Knox Creek complex includes one underground room and pillar mine, one surface mine, one highwall miner and a preparation plant. Production from the underground mine is belted by conveyor system to the preparation plant, while coal requiring processing from the surface mine, including coal from the highwall miner, is trucked to the preparation plant. The preparation plant has a feed capacity of 650 tons per hour. The preparation plant serves customers on the Norfolk Southern rail system with unit trains of up to 100 railcars.

Coal Reserves

We estimate that, as of December 31, 2009, we had total recoverable reserves of approximately 2.4 billion tons consisting of both proven and probable reserves. "Reserves" are defined by the SEC Industry Guide 7 as that part of a mineral deposit, which could be economically and legally extracted or produced at the time of the reserve determination. "Recoverable" reserves means coal that is economically recoverable using existing equipment and methods under federal and state laws currently in effect. Approximately 1.5 billion tons of reserves are classified as proven reserves. "Proven (measured) reserves" are defined by the SEC Industry Guide 7 as 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 closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established. The remaining approximately 0.9 billion tons of our reserves are classified as probable reserves. "Probable reserves" are defined by the SEC Industry Guide 7 as 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.

Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our internal engineers, geologists and finance associates. Reserve estimates are updated annually using geologic data taken from drill holes, adjacent mine workings, outcrop prospect openings and other sources. Coal tonnages are categorized according to coal quality, seam thickness, mineability and location relative to existing mines and infrastructure. In accordance with applicable industry standards, proven reserves are those for which reliable data points are spaced no more than 2,700 feet apart. Probable reserves are those for which reliable data points are spaced 2,700 feet to 7,900 feet apart. Further scrutiny is applied using geological criteria and other factors related to profitable extraction of the coal. These criteria include seam height, roof and floor conditions, yield and marketability.

As with most coal-producing companies in Central Appalachia, the majority of our coal reserves are controlled pursuant to leases from third-party landowners. The leases are generally long-term in nature (original term five to fifty years or until the mineable and merchantable coal reserves are exhausted), and substantially all of the leases contain provisions that allow for automatic extension of the lease term as long as mining continues. These leases convey mining rights to the coal producer in exchange for a per ton or percentage of gross sales price royalty payment to the lessor. However, approximately 18% of our reserve holdings are owned and require no royalty or per ton payment to other parties. Royalty expense for coal reserves from our producing properties (owned and leased) was approximately 4.4% of Produced coal revenue for the year ended December 31, 2009.

The following table provides proven and probable reserve data by "status" (i.e., location, owned or leased, assigned or unassigned, etc.) as of December 31, 2009:

Recoverable Reserves (1)

Resource Group	**Location (2)**	**Total**	**Proven**	**Probable**	**Assigned (3)**	**Unassigned (3)**	**Owned**	**Leased**
(In Thousands of Tons)								
West Virginia								
Black Castle	Boone County	83,440	57,364	26,076	39,297	44,143	538	82,902
Delbarton	Mingo County	285,761	120,440	165,321	140,263	145,498	25	285,736
Edwight	Raleigh County	4,851	4,851	-	4,851	-	-	4,851
Elk Run	Boone County	106,756	73,963	32,793	80,734	26,022	4,660	102,096
Endurance	Boone County	20,871	20,871	-	20,871	-	20,831	40
Green Valley	Nicholas County	11,360	11,360	-	10,417	943	-	11,360
Guyandotte	Wyoming County	45,336	17,366	27,970	2,100	43,236	330	45,006
Independence	Boone County	42,881	41,571	1,310	30,293	12,588	9,482	33,399
Inman	Boone County	45,501	43,986	1,515	-	45,501	-	45,501
Logan County	Logan County	102,302	84,718	17,584	75,134	27,168	2,388	99,914
Mammoth	Kanawha County	131,628	100,705	30,923	73,881	57,747	42,596	89,032
Marfork	Raleigh County	128,977	100,849	28,128	70,759	58,218	815	128,162
Nicholas Energy	Nicholas County	86,161	48,258	37,903	43,745	42,416	33,554	52,607
Progress	Boone County	21,860	21,860	-	21,860	-	-	21,860
Rawl	Mingo County	107,853	80,623	27,230	73,985	33,868	1,333	106,520
Republic Energy	Raleigh County	77,211	65,626	11,585	77,211	-	-	77,211
Stirrat	Logan County	9,512	7,330	2,182	4,631	4,881	-	9,512
Kentucky								
Coalgood Energy	Harlan County	20,906	12,939	7,967	3,361	17,545	2,704	18,202
Long Fork	Pike County	4,964	2,764	2,200	264	4,700	-	4,964
Martin County	Martin County	46,967	30,278	16,689	1,905	45,062	1,336	45,631
New Ridge	Pike County	-	-	-	-	-	-	-
Sidney	Pike County	120,685	70,173	50,512	120,685	-	7,028	113,657
Virginia								
Knox Creek	Tazewell County	62,307	46,756	15,551	34,776	27,531	4,552	57,755
Subtotal		1,568,090	1,064,651	503,439	931,023	637,067	132,172	1,435,918
Land Management Companies: (4)								
Black King	Boone County, WV Raleigh County, WV	53,536	40,804	12,732	734	52,802	-	53,536
Boone East	Boone County, WV Kanawha County, WV	138,741	101,268	37,473	4,340	134,401	61,218	77,523
Boone West	Lincoln County, WV Logan County, WV	241,974	92,201	149,773	10,496	231,478	65,553	176,421
Ceres Land	Raleigh County, WV	33,351	24,220	9,131	-	33,351	-	33,351
Rostraver Energy	Various counties, PA	94,086	44,449	49,637	-	94,086	65,728	28,358
Lauren Land	Mingo County, WV Logan County, WV Various counties, KY	171,028	104,814	66,214	11,175	159,853	17,669	153,359
New Market Land	Wyoming County, WV	5,884	2,690	3,194	-	5,884	102	5,782
Raven Resources	Raleigh County, WV Boone County, WV	18,978	18,978	-	-	18,978	-	18,978
Tennessee Consolidated Coal	Various counties, TN	26,907	1,332	25,575	-	26,907	24,054	2,853
Subtotal Land Management		784,485	430,756	353,729	26,745	757,740	234,324	550,161
Other	N/A	57,733	29,680	28,053	12,740	44,993	3,112	54,621
Total		2,410,308	1,525,087	885,221	970,508	1,439,800	369,608	2,040,700

(1) Recoverable reserves represents the amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods under current law.

(2) All of the recoverable reserves listed are in Central Appalachia, except for the Rostraver reserves, which are located in Northern Appalachia and Lauren Land reserves, a portion of which are located in the Illinois Basin. The reserve numbers of each Resource Group contain a moisture factor specific to the particular reserves of that Resource Group. The moisture factor represents the average moisture present in our delivered coal.

(3) Assigned Reserves represent recoverable reserves that are dedicated to a specific permitted mine; otherwise, the reserves are considered Unassigned. For Land Management Companies, Assigned Reserves have been leased to a third-party and are dedicated to a specific permitted mine of the lessee.

(4) Land management companies are our subsidiaries whose primary purposes are to acquire and hold our reserves.

The categorization of the "quality" (i.e., sulfur content, Btu, coal type, etc.) of coal reserves is as follows:

Resource Group	Recoverable Reserves	Recoverable Reserves [1] Sulfur Content +1% [2]	-1% [2]	Compliance [2]	Avg. Btu as Received [3]	Coal Type [4]
	(In Thousands of Tons Except Average Btu as Received)					
West Virginia						
Black Castle	83,440	33,978	49,462	22,093	12,700	Utility
Delbarton	285,761	111,954	173,807	127,073	13,350	High Vol Met and Utility
Edwight	4,851	1,225	3,626	3,512	12,550	High Vol Met and Utility
Elk Run	106,756	46,795	59,961	50,058	13,700	High Vol Met and Utility
Endurance	20,871	6,443	14,428	6,381	11,850	Utility
Green Valley	11,360	2,550	8,810	9,750	13,100	High Vol Met, Mid Vol Met, and Industrial
Guyandotte	45,336	-	45,336	45,336	13,850	Low Vol Met
Independence	42,881	16,725	26,156	-	12,650	High Vol Met and Utility
Inman	45,501	26,672	18,829	19,549	12,650	High Vol Met and Utility
Logan County	102,302	34,899	67,403	44,840	12,050	High Vol Met, Utility, and Industrial
Mammoth	131,628	22,391	109,237	41,073	12,150	High Vol Met and Utility
Marfork	128,977	51,797	77,180	38,606	14,050	High Vol Met and Utility
Nicholas Energy	86,161	38,466	47,695	28,000	12,450	High Vol Met and Utility
Progress	21,860	9,038	12,822	12,836	12,350	High Vol Met and Utility
Rawl	107,853	27,658	80,195	59,378	12,350	High Vol Met and Utility
Republic	77,211	16,576	60,635	36,980	12,450	High Vol Met and Utility
Stirrat	9,512	204	9,308	7,492	12,300	High Vol Met and Utility
Kentucky						
Coalgood Energy	20,906	4,708	16,198	11,680	13,100	Utility and Industrial
Long Fork	4,964	3,500	1,464	-	12,850	Utility
Martin County	46,967	33,900	13,067	4,888	12,500	Utility
New Ridge	-	-	-	-	-	N/A
Sidney	120,685	47,878	72,807	52,545	13,200	Utility
Virginia						
Knox Creek	62,307	9,193	53,114	38,491	12,350	High Vol Met and Utility
Subtotal	1,568,090	546,550	1,021,540	660,561		
Land Management Companies:						
Black King	53,536	99	53,437	36,858	12,150	Low Vol Met, High Vol Met and Utility
Boone East	138,741	34,939	103,802	36,789	12,500	Low Vol Met, High Vol Met and Utility
Boone West	241,974	130,063	111,911	79,369	13,350	High Vol Met and Utility
Ceres Land	33,351	5,991	27,360	12,740	12,700	High Vol Met and Utility
Rostraver Energy	94,086	94,086	-	-	14,050	High Vol Met, Utility, and Industrial
Lauren Land	171,028	88,195	82,833	62,286	12,700	High Vol Met and Utility
New Market Land	5,884	-	5,884	5,884	12,700	High Vol Met and Low Vol Met
Raven Resources	18,978	7,449	11,529	1,369	12,100	High Vol Met and Utility
Tennessee Consolidated Coal	26,907	20,353	6,554	4,816	13,000	Mid Volume Met, Utility, and Industrial
Subtotal Land Management	784,485	381,175	403,310	240,111		
Other	57,733	6,638	51,095	45,948	12,800	Various
Total	2,410,308	934,363	1,475,945	946,620		

(1) The reserve numbers of each Resource Group contain a moisture factor specific to the particular reserves of that Resource Group. The moisture factor represents the average moisture present in our delivered coal.
(2) +1% or -1% refers to sulfur content as a percentage in coal by weight. Compliance coal is less than 1% sulfur content by weight and is included in the -1% column.
(3) Represents an estimate of the average Btu per pound in our coal, as it is received by the customer.
(4) Reserve holdings include metallurgical coal reserves. Although these metallurgical coal reserves receive the highest selling price in the current coal market when marketed to steel-making customers, they can also be marketed as an ultra high Btu, low sulfur utility coal for electricity generation.

Compliance compared to non-compliance coal

Coals are sometimes characterized as compliance or non-compliance coal. The phrase compliance coal, as it is commonly used in the coal industry, refers to compliance only with sulfur dioxide emissions standards imposed by Title IV of the Clean Air Act and indicates that when burned, the coal will produce emissions that will meet the current standard without further cleanup. A coal that is 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 labeled compliance. Currently, coal classified as compliance will meet the power plant emission standard of 1.2 pounds of sulfur dioxide per million Btu's of fuel consumed. At December 31, 2009, approximately 0.9 billion tons, or 39%, of our coal reserves met the current standard as compliance coal.

Distribution

We employ transportation specialists who negotiate freight and terminal agreements with various providers, including railroads, barge lines, ocean-going vessels, bulk motor carriers and terminal facilities. Transportation specialists also coordinate with customers, mining facilities and transportation providers to establish shipping schedules that meet each customer's needs.

Our 2009 shipments of 36.7 million tons were loaded from 23 mining complexes. Rail shipments constituted 89% of total shipments, with 28% loaded on Norfolk Southern trains and 61% loaded on CSX trains. The balance was shipped from mining complexes via truck or barge.

Approximately 21% of production was ultimately delivered via the inland waterway system. Coal is loaded directly into barges, or is transported by rail or truck to docks on the Ohio, Big Sandy and Kanawha Rivers and then ultimately transported by barge to electric utilities, integrated steel producers and industrial consumers served by the inland waterway system. We also moved approximately 5% of our production to Great Lakes' ports for transport to various United States and Canadian customers.

Customers and Coal Contracts

We have coal supply commitments with a wide range of electric utilities, steel manufacturers, industrial customers and energy traders and brokers. By offering coal of both steam and metallurgical grades, we are able to serve a diverse customer base. This market diversity allows us to adjust to changing market conditions and sustain high sales volumes. The majority of our customers purchase coal for terms of one year or longer, but we also supply coal on a spot basis for some customers. At December 31, 2009, approximately 61%, 19% and 20% of Trade receivables represents amounts due from utility customers, metallurgical customers and industrial customers, respectively, compared with 75%, 13% and 12%, respectively, as of December 31, 2008. During 2009, we had 27 separate, active coal purchase agreements with Constellation Energy Commodities Group, Inc. ("Constellation"), with terms ranging from one month to two years which, in the aggregate accounted for approximately 19% of our fiscal year 2009 Produced coal revenue. The largest of the 27 agreements represented less than 2% of our fiscal year 2009 Produced coal revenue. As a result, we do not consider our business to be substantially dependent upon any of these agreements, individually or in the aggregate. No other customer accounted for 10% or more of fiscal year 2009 Produced coal revenue or produced tons.

As is customary in the coal industry, we enter into long-term contracts (one year or more in duration) with many of our customers. These arrangements allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. Long-term contracts are a result of extensive negotiations with customers. As a result, the terms of these contracts vary with respect to price adjustment mechanisms, pricing terms, permitted sources of supply, force majeure provisions, quality adjustments and other parameters. Some of the contracts contain price adjustment mechanisms that allow for changes to prices based on statistics from the United States Department of Labor. Coal quality specifications may be especially stringent for steel customers.

For the year ended December 31, 2009, approximately 99% of coal sales volume was pursuant to long-term contracts. We anticipate that in 2010, coal sales volume percentage pursuant to long-term arrangements will be comparable to 2009. As of February 17, 2010, we had contractual sales commitments of approximately 100 million tons, including commitments subject to price reopener and/or optional tonnage provisions. Remaining contractual terms of our sales commitments range from one to ten years with an average volume-weighted remaining term of approximately 2.1 years. Seventy percent of our total contracted sales tons are priced. As of February 17, 2010, we have committed most of our expected 2010 production. In addition, we purchase coal from third-party coal producers from time to time to supplement production and resell this coal to customers.

Suppliers

The main types of goods we purchase are mining equipment and replacement parts, explosives, fuel, tires, steel-related (including roof control) products and lubricants. Although we have many well-established, strategic relationships with our key suppliers, we do not believe that we are dependent on any of our individual suppliers, except as noted below. The supplier base providing mining materials has been relatively consistent in recent years, although there continues to be some consolidation. Consolidation of suppliers of explosives has limited the number of sources for these materials. Although our current supply of explosives is concentrated with one supplier, some alternative sources are available to us in the regions where we operate. Further consolidation of underground equipment suppliers has resulted in a situation where purchases of certain underground mining equipment are concentrated with one principal supplier; however, supplier competition continues to develop. In recent years, demand for certain surface and underground mining equipment and off-the-road tires has increased. As a result, lead times for certain items have generally increased, although no material impact is currently expected to our cash flows, results of operations or financial condition.

Competition

The coal industry in the United States and overseas is highly competitive, with numerous producers selling into all markets that use coal. We compete against large and small producers in the United States and overseas. The NMA estimated that in 2008 there were 28 coal companies in the United States with annual production of 5 million or more tons, which together account for approximately 87% of United States production. According to the NMA, we were the sixth largest coal company in terms of tons produced in 2008, exceeded by Peabody Energy Corporation (“Peabody”), Rio Tinto Energy America, Inc., Arch Coal, Inc. (“Arch”), Foundation Coal Holdings Inc. (“Foundation”) and CONSOL Energy Inc. (“CONSOL”).

We compete with other producers primarily on the basis of price, coal quality, transportation cost and reliability of supply. Continued demand for coal is also dependent on factors outside of our control, including demand for electricity and steel, general economic conditions, environmental and governmental regulations, weather, technological developments, and the availability and cost of alternative fuel sources. 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.

Historically, global coal markets have responded to increased demand and higher prices for coal by increasing production and supply. In recent years, however, capacity expansion has been somewhat limited by the increased costs of mining, high capital requirements, coal seam degradation, reserve depletion, labor shortages, transportation issues related to rail, barge and truck shipments, higher costs related to compliance with new and increasingly stringent regulations, the difficulty of obtaining permits and bonding and other factors. While these constraints persist in major coal producing countries and regions, periods of supply and demand imbalance may be extended and increased pricing volatility may result.

Other Related Operations

We have other related operations and activities in addition to our normal coal production and sales business. The following business activities are included in this category:

Coal Handling Joint Venture. We hold a 50% interest in a joint venture that owns and operates third-party end-user coal handling facilities. Certain of our subsidiaries currently operate the coal handling facilities for the joint venture.

Gas Operations. We hold interests in operations that produce, gather and market natural gas from shallow reservoirs in the Appalachian Basin. In the eastern United States, conventional natural gas reservoirs are located in various types of sedimentary formations at depths ranging from 2,000 to 15,000 feet. The depths of the reservoirs drilled and operated by us range from 2,500 to 5,800 feet.

Nearly all of our gas production is from operations in southern West Virginia. In this region, we own and operate approximately 160 wells, 200 miles of gathering line, and various small compression facilities. Our southern West Virginia operations control approximately 27,000 acres of drilling rights. In addition, we own a majority working interest in 50 wells operated by others, and minority working interests in approximately 13 wells operated by others. The December 2009 average daily production, from the 228 wells owned or controlled, was 2.0 million cubic feet per day. We do not consider our current gas production level, revenues or costs to be material to our cash flows, results of operations or financial condition.

Other. From time to time, we also engage in the sale of certain non-strategic assets such as timber, oil and gas rights, surface properties and reserves. In addition, we have established several contractual arrangements with customers where services other than coal supply are provided on an ongoing basis. None of these contractual arrangements is considered to be material. Examples of such other services include arrangements with several metallurgical and industrial customers to coordinate shipment of coal to their stockpiles, maintain ownership of the coal inventory on their property and sell tonnage to them as it is consumed. We work closely with customers to provide other services in response to the current needs of each individual customer.

Marketing and Sales

Our marketing and sales force, based in the corporate office in Richmond, Virginia, includes sales managers, distribution/traffic managers and administrative personnel.

During the year ended December 31, 2009, we sold 36.7 million tons of produced coal for total Produced coal revenue of $2.3 billion. The breakdown of produced tons sold by market served was 62% utility, 30% metallurgical and 8% industrial. Sales were concluded with over 100 customers. Export shipment revenue totaled approximately $472.1 million, representing approximately 20% of 2009 Produced coal revenue. In 2009, we exported shipments to customers in 13 countries across the globe, which included destinations in Europe, Asia, Africa, South America and North America. Sales are made in United States dollars, which minimizes foreign currency risk.

Employees and Labor Relations

As of December 31, 2009, we had 5,851 employees, including 76 employees affiliated with the United Mine Workers of America ("UMWA"). Relations with employees are generally good, and there have been no material work stoppages in the past ten years.

Environmental, Safety and Health Laws and Regulations

The coal mining industry is 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 mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, water appropriation and legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, endangered plant and wildlife protection, limitations on land use, and storage of petroleum products and substances that are regarded as hazardous under applicable laws. The possibility exists that new legislation or regulations may be adopted that could have a significant impact on our mining operations or on our customers' ability to use coal.

Numerous governmental permits and approvals are required for mining 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 us could provide a basis to revoke existing permits and to deny the issuance of addition permits. We are required to prepare and present to federal, state or local authorities data and/or analysis pertaining to the effect or impact that any proposed exploration for or production of coal 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 that restricts our ability to conduct our mining operations or to do so profitably. Future legislation and administrative regulations may increasingly emphasize the protection of the environment, health and safety and, as a consequence, our activities 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, 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 for all domestic coal producers. We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, even with our substantial efforts to comply with extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time. In 2007, EPA filed suit against us and twenty-seven of our subsidiaries alleging violations of the Federal Clean Water Act. In January 2008, we announced that we had agreed with EPA to settle the lawsuit for a payment of $20 million in penalties. In 2009, we spent approximately $14.1 million to comply with environmental laws and regulations, of which $6.2 million was for reclamation, including $5.3 million for final reclamation. None of these expenditures were capitalized. We anticipate spending approximately $50.1 million and $29.9 million in such non-capital expenditures in 2010 and 2011, respectively. Of these expenditures, $41.2 million and $20.8 million for 2010 and 2011, respectively, are anticipated to be for final reclamation.

Emission Control Technology. We own a majority interest in Coalsolv, LLC ("Coalsolv"), which holds the United States marketing rights for the coal-fired plant emission control technologies developed by Cansolv Technologies, Inc. ("Cansolv"). Cansolv's technologies remove sulfur dioxide (SO_2), nitrogen oxide (NO_x), mercury, carbon dioxide (CO_2), and other greenhouse gases from flue gas emissions. The Cansolv process has been utilized at various industrial facilities around the world, with additional projects underway in China and Canada. Through Coalsolv, we contributed funds for a pilot plant that has been utilized in the United States and Canada for the testing and piloting of the Cansolv SO_2, NO_X, mercury, and CO_2 capture technology on coal-fired power plants.

Mine Safety and Health

Stringent health and safety standards have been in effect since Congress enacted the Federal Coal Mine Health and Safety Act of 1969. The Federal Coal Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed safety and health standards on all aspects of mining operations. A further expansion occurred in June 2006 with the enactment of the Mine Improvement and New Emergency Response Act of 2006 ("MINER Act").

The MINER Act and related Mine Safety and Health Administration ("MSHA") regulatory action require, among other things, improved emergency response capability, increased availability of emergency breathable air, enhanced communication and tracking systems, more available mine rescue teams, increased mine seal strength and monitoring of sealed areas in underground mines, and larger penalties by MSHA for noncompliance by mine operators. Coal producing states, including West Virginia and Kentucky, have passed similar legislation. The bituminous coal mining industry was actively engaged throughout 2009 in activities to achieve compliance with these new requirements. These compliance efforts will continue into 2010.

In 2008, MSHA published final rules implementing Section 4 of the MINER Act that addressed mine rescue, sealing of abandoned areas, refuge alternatives, fire prevention and detection, use of air from the belt entry and civil penalty assessments. MSHA also provided guidance on wireless communication and electronic tracking systems and new requirements for the plugging of coal bed methane wells with horizontal branches in coal seams. Two additional regulations were also published related to measures to achieve alcohol and drug free mines and the use of coal mine dust personal monitors. In February 2009, the United States Court of Appeals for the District of Columbia Circuit held that the 2008 rules were not sufficient to satisfy the requirements of the Miner Act in certain respects, and remanded those portions of the rules to MSHA for reconsideration. New rules issued by the MSHA will likely contain more stringent provisions regarding training of rescue teams.

All of the states in which we operate have state programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry is perhaps the most comprehensive and pervasive system for protection of employee health and safety affecting any segment of industry in the United States. While regulation has a significant effect on our operating costs, our United States competitors are subject to the same regulation.

We measure our success in this area primarily through the use of occupational injury and illness frequency rates. We believe that a superior safety and health regime is inherently tied to achieving productivity and financial goals, with overarching benefits for our shareholders, the community and the environment.

Black Lung. Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to: (i) current and former coal miners totally disabled from black lung disease; and (ii) certain survivors of a miner who dies from black lung disease. The Black Lung Disability Trust Fund, to which we must make certain tax payments based on tonnage sold, provides for the payment of medical expenses to claimants whose last mine employment was before January 1, 1970 and to claimants employed after such date, where no responsible coal mine operator has been identified for claims or where the responsible coal mine operator has defaulted on the payment of such benefits. In addition to federal acts, we are also liable under various state statutes for black lung claims. Federal benefits are offset by any state benefits paid.

Workers' Compensation. We are liable for workers' compensation benefits for traumatic injuries under state workers' compensation laws in the states in which we have operations. Workers' compensation laws are administered by state agencies with each state having its own set of rules and regulations regarding compensation owed to an employee injured in the course of employment.

Coal Industry Retiree Health Benefit Act of 1992 and Tax Relief and Retiree Health Care Act of 2006. The Coal Industry Retiree Health Benefit Act of 1992 ("Coal Act") provides for the funding of health benefits for certain UMWA retirees. The Coal Act established the Combined Benefit Fund ("CBF") into which "signatory operators" and "related persons" are obligated to pay annual premiums for covered beneficiaries. The Coal Act also created a second benefit fund, the 1992 Benefit Plan, for miners who retired between July 21, 1992 and September 30, 1994 and whose former employers are no longer in business. On December 20, 2006, President Bush signed the Tax Relief and Retiree Health Care Act of 2006. This legislation includes important changes to the Coal Act that impacts all companies required to contribute to the CBF. Effective October 1, 2007, the SSA revoked all beneficiary assignments made to companies that did not sign a 1988 UMWA contract ("reachback companies"), but phased-in their premium relief. As a pre-1988 signatory, our related reachback companies received the applicable premium relief. Effective October 1, 2007, reachback companies paid only 55% of their plan year 2008 assessed premiums, 40% of their plan year 2009 assessed premiums, and will pay 15% of their plan year 2010 assessed premiums. General United States Treasury money will be transferred to the CBF to make up the difference. After 2010, reachback companies will have no further obligations to the CBF, and transfers from the United States Treasury will cover all of the health care costs for retirees and dependents previously assigned to reachback companies.

Pension Protection Act. The Pension Protection Act of 2006 ("Pension Act") has simplified and transformed the 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, made permanent the diversification rights and investment education provisions for plan participants and encouraged automatic enrollment in defined contribution 401(k) plans. In general, most provisions of the Pension Act took effect for plan years beginning on or after December 31, 2007. 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 included a funding target phase-in provision consisting of a 92% funding target in 2008, 94% in 2009, 96% in 2010, and 100% thereafter. Plans with a funded ratio of less than 80%, or less than 70% using special assumptions, are deemed to be "at risk" and are subject to additional funding requirements. As of December 31, 2009, our pension plan was underfunded by $55.6 million. We currently expect to make voluntary contributions in 2010 of approximately $20 million. The funded status at the end of fiscal year 2010, and the need for additional future required contributions, will depend primarily on the actual return on assets during the year and the discount rate at the end of the year.

Environmental Laws

Surface Mining Control and Reclamation Act. The Surface Mining Control and Reclamation Act, ("SMCRA"), which is administered by the Office of Surface Mining Reclamation and Enforcement ("OSM"), establishes mining, environmental protection and reclamation standards for all aspects of surface mining as well as many aspects of deep mining. The SMCRA and similar state statutes require, among other things, the restoration of mined property in accordance with specified standards and an approved reclamation plan. In addition, the Abandoned Mine Land Fund, which is part of the SMCRA, imposes a fee on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is $0.315 per ton on surface-mined coal and $0.135 per ton on deep-mined coal. A mine operator must submit a bond or otherwise secure the performance of its reclamation obligations. Mine operators must receive permits and permit renewals for surface mining operations from the OSM or, where state regulatory agencies have adopted federally approved state programs under the act, the appropriate state regulatory authority. We accrue for reclamation and mine-closing liabilities in accordance with accounting principals generally accepted in the United States ("GAAP"). See Note 9 to the Notes to Consolidated Financial Statements.

Clean Water Act. Section 301 of the Clean Water Act prohibits the discharge of a pollutant from a point source into navigable waters of the United States except in accordance with a permit issued under either Section 402 or Section 404 of the Clean Water Act. Navigable waters are broadly defined to include streams, even those that are not navigable in fact, and may include wetlands. All mining operations in Appalachia generate excess material, which are typically placed in fills in adjacent valleys and hollows. Likewise, coal refuse disposal areas and coal processing slurry impoundments are located in valleys and hollows. These areas frequently contain intermittent or perennial streams, which are considered navigable waters under the Clean Water Act. An operator must secure a Clean Water Act permit before filling such streams. For approximately the past twenty-five years, operators have secured Section 404 fill permits that authorize the filling of navigable waters with material from various forms of coal mining. Operators have also obtained permits under Section 404 for the construction of slurry impoundments. Discharges from these structures require permits under Section 402 of the Clean Water Act. Section 402 discharge permits are generally not suitable for authorizing the construction of fills in navigable waters.

Clean Air Act. Coal contains impurities, including sulfur, mercury, chlorine, nitrogen oxide and other elements or compounds, many of which are released into the air when coal is burned. The Clean Air Act and corresponding state laws extensively regulate emissions into the air of particulate matter and other substances, including sulfur dioxide, nitrogen oxide and mercury. Although these regulations apply directly to impose certain requirements for the permitting and operation of our mining facilities, by far their greatest impact on us and the coal industry generally is the effect of emission limitations on utilities and other customers. Owners of coal-fired power plants and industrial boilers have been required to expend considerable resources to comply with these air pollution standards. The United States Environmental Protection Agency ("EPA") has imposed or attempted to impose tighter emission restrictions in a number of areas, some of which are currently subject to litigation. The general effect of such tighter restrictions could be to reduce demand for coal. This in turn may result in decreased production and a corresponding decrease in revenue and profits.

National Ambient Air Quality Standards. Ozone is produced by a combination of two precursor pollutants: volatile organic compounds and nitrogen oxide, a by-product of coal combustion. Particulate matter is emitted by sources burning coal as fuel, including coal fired power plants. States are required to submit to EPA revisions to their State Implementation Plans ("SIPs") that demonstrate the manner in which the states will attain National Ambient Air Quality Standards ("NAAQS") every time a NAAQS is revised by EPA. In 2006, EPA adopted a new NAAQS for fine particulate matter, which a number of states and environmental advocacy groups challenged as not sufficiently stringent to satisfy Clean Air Act requirements; in February 2009, the United States Court of Appeals for the District of Columbia Circuit agreed that EPA had inadequately explained its decision regarding several aspects of the NAAQS and remanded those to EPA for reconsideration, a process that could lead to more stringent NAAQS for fine particulate matter. EPA also adopted a more stringent ozone NAAQS on March 27, 2008. In addition, in 2009 and early 2010, EPA has proposed even more stringent NAAQS for ozone, SO_2, and NO_2. Revised SIPs for ozone, SO_2, NO_2, and fine particulates could require electric power generators to further reduce particulate, nitrogen oxide and sulfur dioxide emissions. In addition to the SIP process, the Clean Air Act permits states to assert claims against sources in other "upwind" states alleging that emission sources including coal fired power plants in the upwind states are preventing the "downwind" states from attaining a NAAQS. The new NAAQS for ozone and fine particulates, as well as claims by affected states, could result in additional controls being required of coal fired power plants and we are unable to predict the effect on markets for our coal.

Acid Rain Control Provisions. The acid rain control provisions promulgated as part of the Clean Air Act Amendments of 1990 in Title IV of the Clean Air Act ("Acid Rain program") required reductions of sulfur dioxide emissions from power plants. The Acid Rain program is now a mature program and we believe that any market impacts of the required controls have likely been factored into the price of coal in the national coal market.

Regional Haze Program. EPA promulgated a regional haze program designed to protect and to improve visibility at and around so-called Class I Areas, which are generally National Parks, National Wilderness Areas and International Parks. This program may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around the Class I Areas. Moreover, the program requires certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxide and particulate matter. States were required to submit Regional Haze SIPs to EPA by December 17, 2007. Many states did not meet the December 17, 2007, deadline and we are unable to predict the impact on the coal market of the failure to submit Regional Haze SIPs by the deadline or of any subsequent submissions deadlines.

New Source Review Program. Under the Clean Air Act, new and modified sources of air pollution must meet certain new source standards ("New Source Review Program"). In the late 1990s, EPA filed lawsuits against many coal-fired plants in the eastern United States alleging that the owners performed non-routine maintenance, causing increased emissions that should have triggered the application of these new source standards. Some of these lawsuits have been settled, with the owners agreeing to install additional pollution control devices in their coal-fired plants. The remaining litigation and the uncertainty around the New Source Review Program rules could adversely impact utilities' demand for coal in general or coal with certain specifications, including the coal we produce.

Multi-Pollutant Strategies. In March 2005, EPA issued two closely related rules designed to significantly reduce levels of sulfur dioxide, nitrogen oxide and mercury: the Clean Air Interstate Rule ("CAIR") and the Clean Air Mercury Rule ("CAMR"). CAIR sets a "cap-and-trade" program in 28 states and the District of Columbia to establish emissions limits for sulfur dioxide and nitrogen oxide, by allowing utilities to buy and sell credits to assist in achieving compliance with the

NAAQS for 8-hour ozone and fine particulates. CAMR as promulgated will cut mercury emissions nearly 70% by 2018 through a "cap-and-trade" program. Both rules were challenged in numerous lawsuits and the United States Court of Appeals for the District of Columbia Circuit vacated CAMR and remanded it to EPA for reconsideration on February 8, 2008. The same court vacated the CAIR on July 11, 2008, but subsequently revised its remedy to a remand to EPA for reconsideration on December 23, 2008. EPA is preparing its response to the remand, but the court did not impose a response date. Regardless of the outcome of litigation on either rule, stricter controls on emissions of SO_2, NO_X and mercury are likely in some form. Any such controls may have an impact on the demand for our coal. The EPA Administrator announced in December 2009 that EPA will propose a new air toxics Maximum Achievable Control Technology (MACT) standard for power plants in 2010 and finalize it in 2011. The new rule will regulate several air toxics in addition to mercury and will likely have a significant impact on the levels of controls required on power plants. Such rules and controls may have a significant, but undetermined, impact on the demand for coal.

Global Climate Change

Global climate change continues to attract considerable public and scientific attention. Widely publicized scientific reports, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate Change released in 2007, have also engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. A considerable and increasing amount of attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants. According to the EIA report, "Emissions of Greenhouse Gases in the United States 2007," coal combustion accounts for 30% of man-made greenhouse gas emissions in the United States. Legislation was introduced in Congress in the past several years to reduce greenhouse gas emissions in the United States and, although no bills to reduce such emissions have yet to pass both houses of Congress, bills to reduce such emissions remain pending and others are likely to be introduced. President Obama campaigned in favor of a "cap-and-trade" program to require mandatory greenhouse gas emissions reductions and since his election has continued to express support for such legislation, contrary to the previous administration.

The issue of greenhouse gasses has been the subject of a number of recent court cases. Most recently, in the case of Massachusetts v. EPA, the United States Supreme Court ("Supreme Court") found that greenhouse gases are air pollutants covered by the Clean Air Act. The Supreme Court held that the administrator of the EPA must determine whether emissions of greenhouse gases from new motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare, or whether the science is too uncertain to make a reasoned decision. The Supreme Court decision resulted from a petition for rulemaking under section 202(a) of the Clean Air Act filed by more than a dozen environmental, renewable energy, and other organizations. On December 7, 2009, the EPA Administrator signed two distinct findings regarding greenhouse gases under section 202(a) of the Clean Air Act. One finding is that the current and projected concentrations of the six key well-mixed greenhouse gases--carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)--in the atmosphere threaten the public health and welfare of current and future generations. The second finding is that the combined emissions of these well-mixed greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas pollution which threatens public health and welfare. These findings do not themselves impose any requirements on industry or other entities. However, this action is a prerequisite to finalizing the EPA's proposed greenhouse gas emission standards for light-duty vehicles, which were jointly proposed by EPA and the Department of Transportation's National Highway Safety Administration on September 15, 2009. In addition, these findings may trigger permitting and other requirements for stationary sources regarding CO_2 and other greenhouse gasses. Such requirements may have a significant, but undetermined impact on the ability to mine and use coal.

In December 2009, 192 countries attended the Copenhagen Climate Change Summit to discuss actions to be taken to combat global climate change. Leaders from more than two dozen countries representing over 80 percent of the world's SO_2 emissions negotiated the Copenhagen Accord, which puts a non-binding expectation on all of the major emitting countries to officially record their commitments to reduce SO_2 emissions by January 31, 2010. The United States participated in the conference and stated a goal to reduce emissions in the range of 17 percent below 2005 levels by 2020, 42 percent below 2005 levels by 2030, and 83 percent below 2005 levels by 2050, which is substantially in line with the energy and climate legislation passed by the United States House of Representatives in 2009. The ultimate outcome of the Copenhagen Accord and any treaty or other arrangement ultimately adopted by the United States or other countries, may have a material adverse impact on the global supply and demand for coal. This is particularly true if cost effective technology for the capture and sequestration of carbon dioxide is not sufficiently developed. Technologies that may significantly reduce emissions into the atmosphere of greenhouse gases from coal combustion, such as carbon capture and sequestration (which captures carbon dioxide at major sources such as power plants and subsequently stores it in nonatmospheric reservoirs such as depleted oil and gas reservoirs, unmineable coal seams, deep saline formations, or the deep ocean) have attracted and continue to attract the attention of policy makers, industry participants, and the public. For example, in July 2008, EPA proposed rules that would establish, for the first time, requirements specifically for wells used to inject carbon dioxide into geologic formations. No regulations have been promulgated yet, but the issue of carbon sequestration results in considerable uncertainty, not only regarding rules that may become applicable to carbon dioxide injection wells but also concerning liability for potential impacts of injection, such as groundwater contamination or seismic activity. In addition, technical, environmental, economic, or other factors may delay, limit, or preclude large-scale commercial deployment of such technologies, which could ultimately provide little or no significant reduction of greenhouse gas emissions from coal combustion.

Global climate change continues to attract considerable public and scientific attention and a considerable amount of legislative attention in the United States is being paid to global climate change and the reduction of greenhouse gas emissions, particularly from coal combustion by power plants. Enactment of laws and passage of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions, could result in electric generators switching from coal to other fuel sources.

Permitting and Compliance

Our operations are principally regulated under surface mining permits issued pursuant to the SMCRA and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. We currently have over 500 surface mining permits. In conjunction with the surface mining permits, most operations hold national pollutant discharge elimination system permits pursuant to the Clean Water Act and state counterpart water pollution control laws for the discharge of pollutants to waters. These permits are issued for terms of five years. Additionally, the Clean Water Act requires permits for operations that fill waters of the United States. Valley fills and refuse impoundments are authorized under permits issued under the Clean Water Act by the United States Army Corps of Engineers. Additionally, certain surface mines and preparation plants have permits issued pursuant to the Clean Air Act and state counterpart clean air laws allowing and controlling the discharge of air pollutants. These permits are primarily permits allowing initial construction (not operation) and they do not have expiration dates.

We believe we have obtained all permits required for current operations under the SMCRA, Clean Water Act and Clean Air Act and corresponding state laws. We believe that we are in compliance in all material respects with such permits, and routinely correct violations in a timely fashion in the normal course of operations. The expiration dates of the permits are largely immaterial as the law provides for a right of successive renewal. The cost of obtaining surface mining, clean water and air permits can vary widely depending on the scientific and technical demonstrations that must be made to obtain the permits. However, our cost of obtaining a permit is rarely more than $500,000 and our cost of obtaining a renewal is rarely more than $5,000. It is impossible to predict the full impact of future judicial, legislative or regulatory developments on our operations, because the standards to be met, as well as the technology and length of time available to meet those standards, continue to develop and change.

We believe, based upon present information available to us, that accruals with respect to future environmental costs are adequate. For further discussion of our costs, see Note 9 to the Notes to Consolidated Financial Statements. However, the imposition of more stringent requirements under environmental laws or regulations, new developments or changes regarding site cleanup costs or the allocation of such costs among potentially responsible parties, or a determination that we are potentially responsible for the release of hazardous substances at sites other than those currently identified, could result in additional expenditures or the provision of additional accruals in expectation of such expenditures.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on waste generators, site owners and lessees and others regardless of fault or the legality of the original disposal activity. Although EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could implicate the liability provisions of the statute. Under EPA’s Toxic Release Inventory process, companies are required annually to report the use, manufacture or processing of listed toxic materials that exceed defined thresholds, including chemicals used in equipment maintenance, reclamation, water treatment and ash received for mine placement from power generation customers. 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 under CERCLA.

Endangered Species Act

The federal Endangered Species Act and counterpart state legislation protect species threatened with possible extinction. Protection of endangered species may have the effect of prohibiting or delaying us from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species. Based on the species that have been identified on our properties to date and the current application of applicable laws and regulations, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our ability to mine coal from our properties in accordance with current mining plans.

Available Information

We make available, free of charge through our Internet website, www.masseyenergyco.com, our annual report, quarterly reports, current reports, proxy statements, Section 16 reports and other information (and any amendments thereto) as soon as practicable after filing or furnishing the material to the SEC, in addition to, our Corporate Governance Guidelines, codes of ethics and the charters of the Audit, Compensation, Executive, Finance, Governance and Nominating, and Safety, Environmental, and Public Policy Committees. These materials also may be requested at no cost by telephone at (866) 814-6512 or by mail at: Massey Energy Company, Post Office Box 26765, Richmond, Virginia 23261, Attention: Investor Relations.

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 “Executive Officers of the Registrant” (included herein pursuant to Item 401(b) of Regulation S-K).

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GLOSSARY OF SELECTED TERMS

Ash. Impurities consisting of iron, aluminum and other incombustible matter that are contained in coal. Since ash increases the weight of coal, it adds to the cost of handling and can affect the burning characteristics of coal.

Bituminous coal. The most common type of coal with moisture content less than 20% by weight and heating value of 10,500 to 14,000 Btu per pound.

British thermal unit, or "Btu." A measure of the thermal energy required to raise the temperature of one pound of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

Central Appalachia. Coal producing states and regions of eastern Kentucky, eastern Tennessee, western Virginia and southern West Virginia.

Coal seam. Coal deposits occur in layers. Each layer is called a "seam."

Coke. A hard, dry carbon substance produced by heating coal to a very high temperature in the absence of air. Coke is used in the manufacture of iron and steel. Its production results in a number of useful byproducts.

Compliance coal. Described in Item 1. Business, under the heading "Coal Reserves."

Continuous miner. A mining machine with a continuously rolling cutting cylinder used in underground and highwall mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation.

Direct-ship coal. Coal that is shipped without first being processed in a preparation plant.

Deep mine. An underground coal mine.

Dragline. A large machine used in the surface mining process to remove the overburden, or layers of earth and rock covering a coal seam. The dragline has a large bucket suspended from the end of a long boom. The bucket, which is suspended by cables, is able to scoop up substantial amounts of overburden as it is dragged across the excavation area.

Fossil fuel. Fuel such as coal, petroleum or natural gas formed from the fossil remains of organic material.

Highwall mining. Described in Item 1. Business, under the heading "Mining Methods."

High vol met coal. Coal that averages approximately 35% volatile matter. Volatile matter refers to the impurities that become gaseous when heated to certain temperatures.

Illinois Basin. The Illinois Basin consists of the coal producing areas in Illinois, Indiana and western Kentucky.

Industrial coal. Coal used by industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Long-term contracts. Contracts with terms of one year or longer.

Longwall mining. Described in Item 1. Business, under the heading "Mining Methods."

Low vol met coal. Coal that averages approximately 20% volatile matter. Volatile matter refers to the impurities that become gaseous when heated to certain temperatures.

Metallurgical coal. The various grades of coal suitable for carbonization to make coke for steel manufacture. Also known as "met" coal, it possesses four important qualities: volatility, which affects coke yield; the level of impurities, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Met coal has a particularly high Btu heat content, but low ash content.

Mine. A mine consists of those operating assets necessary to produce coal from surface or underground locations.

Nitrogen oxide (NOx). Nitrogen oxide is produced as a gaseous by-product of coal combustion.

Northern Appalachia. Northern Appalachia consists of the bituminous coal producing areas in the states of Pennsylvania, Ohio and Maryland and in the northern part of West Virginia.

Overburden. Layers of earth and rock covering a coal seam. In surface mining operations, overburden is removed prior to coal extraction.

Overburden ratio. The amount of overburden that must be removed to excavate a given quantity of coal. It is commonly expressed in cubic yards per ton of coal or as a ratio comparing the thickness of the overburden with the thickness of the coal bed.

Pillar. An area of coal left to support the overlying strata in an underground mine, sometimes left permanently to support surface structures.

Powder River Basin. The Powder River Basin consists of the coal producing areas in southeast Montana and northeast Wyoming.

Preparation plant. A preparation plant is a facility for crushing, sizing and washing coal to remove rock and other impurities to prepare it for use by a particular customer. Preparation plants are usually located on a mine site, although one plant may serve several mines. The washing process has the added benefit of removing some of the coal's sulfur content.

Probable reserves. Described in Item 1. Business, under the heading "Coal Reserves."

Proven reserves. Described in Item 1. Business, under the heading "Coal Reserves."

Reclamation. The process of restoring land and the environment to their approximate original state following mining activities. The process commonly includes "recontouring" or reshaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers. Reclamation operations are usually underway before the mining of a particular site is completed. Reclamation is closely regulated by both state and federal law.

Reserve. Described in Item 1. Business, under the heading "Coal Reserves."

Resource Group. An organizational unit, generally located within a specific geographic locale, that contains one or more of the following operations related to the mining, processing or shipping of coal: underground mine, surface mine, preparation plant or load-out facility.

Roof. The stratum of rock or other mineral above a coal seam; the overhead surface of a coal working place.

Room and pillar mining. Described in Item 1. Business, under the heading "Mining Methods."

Scrubber (flue gas desulfurization unit). Any of several forms of chemical/physical devices that operate to neutralize sulfur and other greenhouse gases formed during coal combustion. These devices combine the sulfur in gaseous emissions with other chemicals to form inert compounds, such as gypsum, that must then be removed for disposal. Although effective in substantially reducing sulfur from combustion gases, scrubbers require about 6% to 7% of a power plant's electrical output and thousands of gallons of water to operate.

Steam coal. Coal used by power plants and industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal. Also known as utility coal.

Stoker coal. Coal that is sized to a specific, standard range. Stoker coal is typically one quarter inch by one and one quarter to one and three quarter inch.

Sulfur. One of the elements present in varying quantities in coal that reacts with air when coal is burned to form sulfur dioxide.

Sulfur content. Coal is commonly described by its sulfur content due to the importance of sulfur in environmental regulations. "Low sulfur" coal has a variety of definitions, but typically is used to describe coal consisting of 1.0% or less sulfur.

Sulfur dioxide (SO_2). Sulfur dioxide is produced as a gaseous by-product of coal combustion.

Surface mining. Described in Item 1. Business, under the heading “Mining Methods.”

Tons. A “short” or net ton is equal to 2,000 pounds. A “long” or British ton is approximately 2,240 pounds; a “metric” ton is approximately 2,205 pounds. The short ton is the unit of measure referred to in this Annual Report on Form 10-K.

Underground mine. Also known as a “deep” mine. Usually located several hundred feet below the earth’s surface, an underground mine’s coal is removed mechanically and transferred by shuttle car or conveyor to the surface.

Unit train. A railroad train of a specified number of railroad cars carrying only coal. A typical unit train can carry at least 10,000 tons of coal in a single shipment.

Utility coal. Coal used by power plants to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal. Also known as steam coal.

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Item 1A. Risk Factors

We are subject to a variety of risks, including, but not limited to, those risk factors set forth below and those referenced herein to other Items contained in this Annual Report on Form 10-K, including Item 1. Business, under the headings "Customers and Coal Contracts," "Competition," "Environmental, Safety and Health Laws and Regulations," Item 3. Legal Proceedings and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A"), under the headings "Critical Accounting Estimates and Assumptions," "Certain Trends and Uncertainties" and elsewhere in MD&A.

We could be negatively impacted by the competitiveness of the markets in which we compete and declines in the market demand for coal.

We compete with coal producers in various regions of the United States and overseas for domestic and international sales. Continued domestic demand for our coal and the prices that we will be able to obtain primarily will depend upon coal consumption patterns of the domestic electric utility industry and the domestic steel industry. Consumption by the domestic utility industry is affected by the demand for electricity, environmental and other governmental regulations, technological developments and the price of competing coal and alternative fuel supplies including nuclear, natural gas, oil and renewable energy sources, including hydroelectric power. Consumption by the domestic steel industry is primarily affected by economic growth and the demand for steel used in construction as well as appliances and automobiles. In recent years, the competitive environment for coal was impacted by sustained growth in a number of the largest markets in the world, including the United States, China, Japan and India, where demand for both electricity and steel supported pricing for steam and metallurgical coal. The economic stability of these markets has a significant effect on the demand for coal and the level of competition in supplying these markets. The cost of ocean transportation and the value of the United States dollar in relation to foreign currencies significantly impact the relative attractiveness of our coal as we compete on price with other foreign coal producing sources. During the last several years, the United States coal industry has experienced increased consolidation, which has contributed to the industry becoming more competitive. Increased competition by competing coal producers or producers of alternate fuels in the markets in which we serve could cause a decrease in demand and/or pricing for our coal, adversely impacting our cash flows, results of operations or financial condition.

Portions of our coal reserves possess quality characteristics that enable us to mine, process and market them as either metallurgical coal or high quality steam coal, depending on the prevailing conditions in the markets for metallurgical and steam coal. A decline in the metallurgical market relative to the steam market could cause us to shift coal from the metallurgical market to the steam market, potentially reducing the price we could obtain for this coal and adversely impacting our cash flows, results of operations or financial condition.

Demand for our coal depends on its price and quality and the cost of transporting it to our customers.

Coal prices are influenced by a number of factors and may vary dramatically by region. The two principal components of the price of coal are the price of coal at the mine, which is influenced by mine operating costs and coal quality, and the cost of transporting coal from the mine to the point of use. The cost of mining the coal is influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. Underground mining is generally more expensive than surface mining as a result of higher costs for labor (including reserves for future costs associated with labor benefits and health care) and capital costs (including costs for mining equipment and construction of extensive ventilation systems). As of January 31, 2010, we operated 42 active underground mines, including two which employ both room and pillar and longwall mining, and 14 active surface mines, with 12 highwall miners.

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 coal a less competitive source of energy. Such increases could have a material impact on our ability to compete with other energy sources and on our cash flows, results of operations or financial condition. Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country or the world, including coal imported into the United States. For instance, coal mines in the western United States could become an increasingly attractive source of coal to consumers in the eastern part of the United States if the costs of transporting coal from the west were significantly reduced and/or rail capacity was increased.

A significant decline in coal prices in general could adversely affect our operating results and cash flows.

Our results are highly dependent upon the prices we receive for our coal. Decreased demand for coal, both domestically and internationally, could cause spot prices and the prices we are able to negotiate on long-term contracts to decline. The lower prices could negatively affect our cash flows, results of operations or financial condition, if we are unable to increase productivity and/or decrease costs in order to maintain our margins.

We depend on continued demand from our customers.

Reduced demand from or the loss of our largest customers could have an adverse impact on our ability to achieve projected revenue. Decreases in demand may result from, among other things, a reduction in consumption by the electric generation industry and/or the steel industry, the availability of other sources of fuel at cheaper costs and a general slow-down in the economy. When our contracts with customers expire, there can be no assurance that the customers either will extend or enter into new long-term contracts or, in the absence of long-term contracts, that they will continue to purchase the same amount of coal as they have in the past or on terms, including pricing terms, as favorable as under existing arrangements. In the event that a large customer account is lost or a long-term contract is not renewed, profits could suffer if alternative buyers are not willing to purchase our coal on comparable terms.

There may be adverse changes in price, volume or terms of our existing coal supply agreements.

Many of our coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. These contracts may be adjusted based on inflation or deflation and/or changes in the factors affecting the cost of producing coal, such as taxes, fees, royalties and changes in the laws regulating the mining, production, sale or use of coal. In a limited number of contracts, failure of the parties to agree on a price under those provisions may allow either party to terminate the contract. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or the customer for the duration of specified events beyond the control of the affected party. Most coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as Btu, sulfur content, ash content, grindability and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or termination of the contracts.

Our financial condition may be adversely affected if we are required by some of our customers to provide performance assurances for certain below-market sales contracts.

Contracts covering a significant portion of our contracted sales tons contain provisions that could require us to provide performance assurances if we experience a material adverse change or, under certain other contracts, if the customer believes our creditworthiness has become unsatisfactory. Generally, under such contracts, performance assurances are only required if the contract price per ton of coal is below the current market price of the coal. In addition, we may from time to time enter into coal sale agreements that require a posting of collateral to the extent we are "out of the money" on the total contracted sales in excess of $15 million (as of December 31, 2009, no posting was required). Certain of the contracts limit the amount of performance assurance to a per ton amount in excess of the contract price, while others have no limit. The performance assurances are generally provided by the posting of a letter of credit, cash collateral, other security, or a guaranty from a creditworthy guarantor. As of December 31, 2009, we have not received any requests from any of our customers to provide performance assurances. If we are required to post performance assurances on some or all of our contracts with performance assurances provisions, there could be a material adverse impact on our cash flows, results of operations or financial condition.

The level of our indebtedness could adversely affect our ability to grow and compete and prevent us from fulfilling our obligations under our contracts and agreements.

At December 31, 2009, we had $1,319.1 million of total indebtedness outstanding, which represented 51.2% of our total book capitalization. We have significant debt, lease and royalty obligations. Our ability to satisfy debt service, lease and royalty obligations and to effect any refinancing of indebtedness will depend upon future operating performance, which will be affected by prevailing economic conditions in the markets that we serve as well as financial, business and other factors, many of which are beyond our control. We may be unable to generate sufficient cash flow from operations and future borrowings, or other financings may be unavailable in an amount sufficient to enable us to fund our debt service, lease and royalty payment obligations or our other liquidity needs. We also may be able to incur substantial additional indebtedness in the future under the terms of our $175 million asset-based loan credit facility ("ABL Facility") or by other means. Our ABL Facility provides for a revolving line of credit of up to $175.0 million, of which $98.4 million was available as of December 31, 2009. The addition of new debt to our current debt levels could increase the related risks that we now face.

Our relative amount of debt could have material consequences to our business, including, but not limited to: (i) making it more difficult to satisfy debt covenants and debt service, lease payments and other obligations; (ii) making it more difficult to pay quarterly dividends as we have in the past; (iii) increasing our vulnerability to general adverse economic and industry conditions; (iv) limiting our ability to obtain additional financing to fund future acquisitions, working capital, capital expenditures or other general corporate requirements; (v) reducing the availability of cash flows from operations to fund acquisitions, working capital, capital expenditures or other general corporate purposes; (vi) limiting our flexibility in planning for, or reacting to, changes in the business and the industry in which we compete; or (vii) placing us at a competitive disadvantage with competitors with relatively lower amounts of debt. Any of the above-listed factors could have an adverse effect on our business, financial condition and results of operations and our ability to meet our debt payment obligations.

The covenants in our credit facility and the indentures governing debt instruments impose restrictions that may limit our operating and financial flexibility.

Our ABL Facility contains a number of significant restrictions and covenants that may limit our ability and our subsidiaries' ability to, among other things: (1) incur additional indebtedness; (2) increase common stock dividends above specified levels; (3) make loans and investments; (4) prepay, redeem or repurchase debt; (5) engage in mergers, consolidations and asset dispositions; (6) engage in affiliate transactions; (7) create any lien or security interest in any real property or equipment; (8) engage in sale and leaseback transactions; and (9) make distributions from subsidiaries. A decline in our operating results or other adverse factors, including a significant increase in interest rates, could result in us being unable to comply with certain covenants contained in the ABL Facility, which become operative only when our Average Excess Availability (as defined in the ABL Facility) is less than $30 million. These financial covenants include a Minimum Consolidated Fixed Charge Ratio of 1.00 to 1.00 and a minimum Consolidated Net Worth of $550 million under the terms of the ABL Facility (currently approximately $400 million as adjusted for Accounting Changes).

The indentures governing certain of our senior notes also contain a number of significant restrictions and covenants that may limit our ability and our subsidiaries' ability to, among other things: (1) incur additional indebtedness; (2) subordinate indebtedness to other indebtedness unless such subordinated indebtedness is also subordinated to the notes; (3) pay dividends or make other distributions or repurchase or redeem our stock or subordinated indebtedness; (4) make investments; (5) sell assets and issue capital stock of restricted subsidiaries; (6) incur liens; (7) enter into agreements restricting our subsidiaries' ability to pay dividends; (8) enter into sale and leaseback transactions; (9) enter into transactions with affiliates; and (10) consolidate, merge or sell all or substantially all of our assets. If we violate these covenants and are unable to obtain waivers from our lenders, our debt under these agreements would be in default and could be accelerated by the lenders and, in the case of an event of default under our ABL Facility, it could permit the lenders to foreclose on our assets securing the loans under the ABL Facility. If the indebtedness is accelerated, we may not be able to repay our debt or borrow sufficient funds to refinance it. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or on terms that are acceptable to us. If our debt is in default for any reason, our cash flows, results of operations or financial condition could be materially and adversely affected. In addition, complying with these covenants may also cause us to take actions that are not favorable to our shareholders and holders of our senior notes and may make it more difficult for us to successfully execute our business strategy and compete against companies that are not subject to such restrictions.

We are subject to being adversely affected by the potential inability to renew or obtain surety bonds.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers' compensation and to satisfy other miscellaneous obligations. These bonds are typically renewable annually. Surety bond issuers and holders may not continue to renew the bonds or may demand additional collateral upon those renewals. We are also subject to increases in the amount of surety bonds required by federal and state laws as these laws change or the interpretation of these laws changes. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal law would have a material adverse impact on us, possibly by prohibiting us from developing properties that we desire to develop. That failure could result from a variety of factors including the following: (i) lack of availability, higher expense or unfavorable market terms of new bonds; (ii) restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our senior notes or revolving credit facilities; (iii) our inability to meet certain financial tests with respect to a portion of the post-mining reclamation bonds; and (iv) the exercise by third-party surety bond issuers of their right to refuse to renew or issue new bonds.

We depend on our ability to continue acquiring and developing economically recoverable coal reserves.

A key component of our future success is our ability to continue acquiring coal reserves for development that have the geological characteristics that allow them to be economically mined. Replacement reserves may not be available or, if available, may not be capable of being mined at costs comparable to those characteristics of the depleting mines. An inability to continue acquiring economically recoverable coal reserves could have a material impact on our cash flows, results of operations or financial condition.

We face numerous uncertainties in estimating economically recoverable coal reserves, and inaccuracies in estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

There are numerous 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 us. Some of the factors and assumptions that impact economically recoverable reserve estimates include: (1) geological conditions; (2) historical production from the area compared with production from other producing areas; (3) the effects of regulations and taxes by governmental agencies; (4) future prices; and (5) future operating costs.

Each of these factors may 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 may vary substantially. As a result, our estimates may not accurately reflect our actual reserves. Actual production, revenues and expenditures with respect to reserves will likely vary from estimates, and these variances may be material.

Mining in Central Appalachia is more complex and involves more regulatory constraints than mining in other areas of the United States, which could affect our mining operations and cost structures in these areas.

The geological characteristics of Central Appalachian coal reserves, such as depth of overburden and coal seam thickness, make them complex and costly to mine. As mines become depleted, replacement reserves may not be available when required or, if available, may not be capable of being mined at costs comparable to those characteristic of the depleting mines. In addition, as compared to mines in other regions, permitting, licensing and other environmental and regulatory requirements are more costly and time consuming to satisfy. These factors could materially adversely affect the mining operations and cost structures of, and our customers' ability to use coal produced by, our mines in Central Appalachia.

Defects in title or loss of any leasehold interests in our properties could limit our ability to mine our properties or result in significant unanticipated costs.

A significant portion of our mining operations occurs on properties that we lease. Title defects or the loss of leases could adversely affect our ability to mine the reserves covered by those leases. Our current practice is to obtain a title review from a licensed attorney prior to leasing property. We generally have not obtained title insurance in connection with acquisitions of coal reserves. In some cases, the seller or lessor warrants property title. Separate title confirmation sometimes is not required when leasing reserves where mining has occurred previously. Our right to mine some of our reserves may be adversely affected if defects in title or boundaries exist. In order to obtain leases to conduct our mining operations on property where these defects exist, we may have to incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease.

If the coal industry experiences overcapacity in the future, our profitability could be impaired.

An increase in the demand for coal could attract new investors to the coal industry, which could spur the development of new mines, and result in added production capacity throughout the industry. Higher price levels of coal could also encourage the development of expanded capacity by new or existing coal producers. Any resulting increases in capacity could reduce coal prices and reduce our margins.

An inability of brokerage sources or contract miners to fulfill the delivery terms of their contracts with us could reduce our profitability.

We sometimes obtain coal from brokerage sources and contract miners to fulfill deliveries under our coal supply agreements. Some of our brokerage sources and contract miners may experience adverse geologic mining, escalated operating costs and/or financial difficulties that make their delivery of coal to us at the contracted price difficult or uncertain. Our profitability or exposure to loss on transactions or relationships such as these may be affected based upon the reliability of the supply or the ability to substitute, when economical, third-party coal sources, with internal production or coal purchased in the market and other factors.

Decreased availability or increased costs of key equipment, supplies or commodities such as diesel fuel, steel, explosives, magnetite and tires could decrease our profitability.

Our operations are dependant on reliable supplies of mining equipment, replacement parts, explosives, diesel fuel, tires, magnetite and steel-related products (including roof bolts). If the cost of any mining equipment or key supplies increases significantly, or if they should become unavailable due to higher industry-wide demand or less production by suppliers, there could be an adverse impact on our cash flows, results of operations or financial condition. The supplier base providing mining materials and equipment has been relatively consistent in recent years, although there continues to be consolidation. This consolidation has resulted in a situation where purchases of explosives and certain underground mining equipment are concentrated with single suppliers. In recent years, mining industry demand growth has exceeded supply growth for certain surface and underground mining equipment and heavy equipment tires. As a result, lead times for certain items have generally increased.

Transportation disruptions could impair our ability to sell coal.

We are dependent on our transportation providers to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lockouts, fuel shortages or other events could temporarily impair our ability to supply coal to customers. Our ability to ship coal could be negatively impacted by a reduction in available and timely rail service. Lack of sufficient resources to meet a rapid increase in demand, a greater demand for transportation to export terminals and rail line congestion all could contribute to a disruption and slowdown in rail service. We continue to experience rail service delays and disruptions in service which are negatively impacting our ability to deliver coal to customers and which may adversely affect our results of operations.

Severe weather may affect our ability to mine and deliver coal.

Severe weather, including flooding and excessive ice or snowfall, when it occurs, can adversely affect our ability to produce, load and transport coal, which may negatively impact our cash flows, results of operations or financial condition.

Federal, state and local laws and government regulations applicable to operations increase costs and may make our coal less competitive than other coal producers.

We incur substantial costs and liabilities under increasingly strict federal, state and local environmental, health and safety and endangered species laws, regulations and enforcement policies. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. The costs of compliance with applicable regulations and liabilities assessed for compliance failure could have a material adverse impact on our cash flows, results of operations or financial condition.

New legislation and new regulations may be adopted which could materially adversely affect our mining operations, cost structure or our customers' ability to use coal. New legislation and new regulations may also require us, as well as our customers, to change operations significantly or incur increased costs. The United States Environmental Protection Agency (the "EPA") has undertaken broad initiatives to increase compliance with emissions standards and to provide incentives to our customers to decrease their emissions, often by switching to an alternative fuel source or by installing scrubbers or other expensive emissions reduction equipment at their coal-fired plants.

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate change, are resulting in increased regulation of coal combustion in many jurisdictions, and interest in further regulation, which could significantly affect demand for our products.

The Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. Such regulation may require significant emissions control expenditures for many coal-fired power plants. As a result, the generators may switch to other fuels that generate less of these emissions or install more effective pollution control equipment, possibly reducing future demand for coal and the construction of coal-fired power plants. The majority of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser's plant or results in specified increases in the cost of coal or its use.

Global climate change continues to attract considerable public and scientific attention. Widely publicized scientific reports, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate Change released in 2007, have also engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. A considerable and increasing amount of attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants. According to the EIA report, "Emissions of Greenhouse Gases in the United States 2007," coal combustion accounts for 30% of man-made greenhouse gas emissions in the United States. Legislation was introduced in Congress in the past several years to reduce greenhouse gas emissions in the United States and, although no bills to reduce such emissions have yet to pass both houses of Congress, bills to reduce such emissions remain pending and others are likely to be introduced. President Obama campaigned in favor of a "cap-and-trade" program to require mandatory greenhouse gas emissions reductions and since his election has continued to express support for such legislation, contrary to the previous administration. The United States Supreme Court's 2007 decision in *Massachusetts v. Environmental Protection Agency* ruled that EPA improperly declined to address carbon dioxide impacts on climate change in a rulemaking related to new motor vehicles. The reasoning of the court decision could affect other federal regulatory programs, including those that directly relate to coal use. In July 2008, EPA published an Advanced Notice of Proposed Rulemaking (ANPR) seeking comments regarding the regulation of greenhouse gas emissions; and in February 2009 the newly appointed administrator of EPA granted a petition by environmental advocacy groups to reconsider an interpretive memorandum by her predecessor in December 2008 that concluded the Clean Air Act's Prevention of Significant Deterioration program does not extend to carbon dioxide emissions, a decision that could lead to carbon dioxide emissions from coal-fired power plants being a consideration in permitting decisions. In addition, a growing number of states in the United States are taking steps to require greenhouse gas emissions reductions from coal-fired power plants. Enactment of laws and promulgation of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions, could result in electric generators switching from coal to other fuel sources.

In December 2009, 192 countries attended the Copenhagen Climate Change Summit to discuss actions to be taken to combat global climate change. Leaders from more than two dozen countries representing over 80 percent of the world's SO_2 emissions negotiated the Copenhagen Accord, which puts a non-binding expectation on all of the major emitting countries to officially record their commitments to reduce SO_2 emissions by January 31, 2010. The United States participated in the conference and stated a goal to reduce emissions in the range of 17 percent below 2005 levels by 2020, 42 percent below 2005 levels by 2030, and 83 percent below 2005 levels by 2050, which is substantially in line with the energy and climate legislation passed by the United States House of Representatives in 2009. The ultimate outcome of the Copenhagen Accord and any treaty or other arrangement ultimately adopted by the United States or other countries, may have a material adverse impact on the global supply and demand for coal. This is particularly true if cost effective technology for the capture and sequestration of carbon dioxide is not sufficiently developed. Technologies that may significantly reduce emissions into the atmosphere of greenhouse gases from coal combustion, such as carbon capture and sequestration (which captures carbon dioxide at major sources such as power plants and subsequently stores it in nonatmospheric reservoirs such as depleted oil and gas reservoirs, unmineable coal seams, deep saline formations, or the deep ocean) have attracted and continue to attract the attention of policy makers, industry participants, and the public. For example, in July 2008, EPA proposed rules that would establish, for the first time, requirements specifically for wells used to inject carbon dioxide into geologic formations. No regulations have been promulgated yet, but the issue of carbon sequestration results in considerable uncertainty, not only regarding rules that may become applicable to carbon dioxide injection wells but also concerning liability for potential impacts of injection, such as groundwater contamination or seismic activity. In addition, technical, environmental, economic, or other factors may delay, limit, or preclude large-scale commercial deployment of such technologies, which could ultimately provide little or no significant reduction of greenhouse gas emissions from coal combustion.

Further developments in connection with legislation, regulations or other limits on greenhouse gas emissions and other environmental impacts from coal combustion, both in the United States and in other countries where we sell coal, could have a material adverse effect on our cash flows, results of operations or financial condition.

Our operations may adversely impact the environment which could result in material liabilities to us.

The processes required to mine coal may cause certain impacts or generate certain materials that might adversely affect the environment from time to time. The mining processes we use could cause us to become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share.

Certain coal that we mine needs to be cleaned at preparation plants, which generally require coal refuse areas and/or slurry impoundments. Such areas and impoundments are subject to extensive regulation and monitoring. Slurry impoundments have been known to fail, releasing large volumes of coal slurry into nearby surface waters and property, resulting in damage to the environment and natural resources, as well as injuries to wildlife. We maintain coal refuse areas and slurry impoundments at a number of our mining complexes. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental impact and associated liability, as well as for fines and penalties.

Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as acid mine drainage ("AMD"). Although we do not currently face material costs associated with AMD, it is possible that we could incur significant costs in the future.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to certain substances or wastes associated with our operations, could result in costs and liabilities that could materially and adversely affect us and could have a material adverse impact on our cash flows, results of operations or financial condition.

The Mine Safety and Health Administration ("MSHA") or other federal or state regulatory agencies may order certain of our mines to be temporarily or permanently closed, which could adversely affect our ability to meet our customers' demands.

MSHA or other federal or state regulatory agencies may order certain of our mines to be temporarily or permanently closed. Our customers may challenge our issuance of force majeure notices in connection with such closures. If these challenges are successful, we may have to purchase coal from third-party sources to satisfy those challenges; negotiate settlements with customers, which may include price reductions, the reduction of commitments or the extension of the time for delivery, terminate customers' contracts or face claims initiated by our customers against us. The resolution of these challenges could have a material adverse impact on our cash flows, results of operations or financial condition.

We must obtain governmental permits and approvals for mining operations, which can be a costly and time-consuming process, can result in restrictions on our operations, and is subject to litigation that may delay or prevent us from obtaining necessary permits.

Our operations are principally regulated under surface mining permits issued pursuant to the Surface Mining Control and Reclamation Act (the "SMCRA") and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. Additionally, the Clean Water Act requires permits for operations that discharge into waters of the United States. Valley fills and refuse impoundments are authorized under permits issued by the United States Army Corps of Engineers. Such permitting under the Clean Water Act has been a frequent subject of litigation by environmental advocacy groups that has resulted in periodic declines in such permits issued by the United States Army Corps of Engineers. Additionally, certain surface mines and preparation plants have permits issued pursuant to the Clean Air Act and state counterpart laws allowing and controlling the discharge of air pollutants. Regulatory authorities exercise considerable discretion in the timing of permit issuance. Requirements imposed by these authorities may be costly and time-consuming and may result in delays in, or in some instances preclude, the commencement or continuation of development or production operations. Adverse outcomes in lawsuits challenging permits or failure to comply with applicable regulations could result in the suspension, denial or revocation of required permits, which could have a material adverse impact on our cash flows, results of operations or financial condition.

The loss of key personnel or the failure to attract qualified personnel could affect our ability to operate the Company effectively.

The successful management of our business is dependent on a number of key personnel. Our future success will be affected by our continued ability to attract and retain highly skilled and qualified personnel. There are no assurances that key personnel will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have an adverse affect on our cash flows, results of operations or financial condition.

Shortages of skilled labor in the Central Appalachian coal industry may pose a risk in achieving high levels of productivity at competitive costs.

Coal mining continues to be a labor-intensive industry. From time to time, we have encountered a shortage of experienced mine workers when the demand and prices for all specifications of coal we mine increased appreciably. During those periods, the hiring of these less experienced workers negatively impacted our productivity and cash costs. A lack of skilled miners could have an adverse impact on our labor productivity and cost and our ability to meet current production requirements to fulfill existing sales commitments or to expand production to meet the increased demand for coal.

Union represented labor creates an increased risk of work stoppages and higher labor costs.

At December 31, 2009, approximately 1.3% of our total workforce was represented by the United Mine Workers of America (the "UMWA"). Our unionized workforce is spread out amongst five of our coal preparation plants. In 2009, these preparation plants handled approximately 15.8% of our coal production. We are currently in the process of negotiating successor collective bargaining agreements for ones that have expired. In connection with these negotiations and with respect to our unionized operations generally, there may be an increased risk of strikes and other labor disputes, as well as higher labor costs. If some or all of our current open shop operations were to become unionized, we could be subject to additional risk of work stoppages, other labor disputes and higher labor costs, which could adversely affect the stability of production and reduce net income.

Legislation has been proposed to the United States Congress to enact a law allowing for workers to choose union representation solely by signing election cards ("Card Check"), which would eliminate the use of secret ballots to elect union representation. While the impact is uncertain, if Card Check legislation is enacted into law, it will be administratively easier for the UMWA to unionize coal mines and may lead to more coal mines becoming unionized.

Inflationary pressures on supplies and labor may adversely affect our profit margins.

Although inflation in the United States has been relatively low in recent years, over the course of the last two to three years, we have been significantly impacted by price inflation in many of the components of our cost of produced coal revenue, such as fuel, steel and labor. If the prices for which we sell our coal do not increase in step with rising costs or if these costs do not decline sufficiently, our profit margins would be reduced and our cash flows, results of operations or financial condition would be adversely affected.

We are subject to various legal proceedings, which may have a material effect on our business.

We are parties to a number of legal proceedings incident to normal business activities. Some of the allegations brought against us are with merit, while others are not. There is always the potential that an individual matter or the aggregation of many matters could have a material adverse effect on our cash flows, results of operations or financial position. See Note 18 of the Notes to Consolidated Financial Statements.

We have significant reclamation and mine closure obligations. If the assumptions underlying our accruals are materially inaccurate, we could be required to expend greater amounts than anticipated.

SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Estimates of our total reclamation and mine-closing liabilities are based upon permit requirements and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by management and engineers. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

Our future expenditures for postretirement benefit and pension obligations could be materially higher than we have predicted if our underlying assumptions are incorrect.

We are subject to long-term liabilities under a variety of benefit plans and other arrangements with current and former employees. These obligations have been estimated based on actuarial assumptions, including actuarial estimates, assumed discount rates, estimates of life expectancy, expected returns on pension plan assets and changes in healthcare costs.

If our assumptions relating to these benefits change in the future or are incorrect, we may be required to record additional expenses, which would reduce our profitability. In addition, future regulatory and accounting changes relating to these benefits could result in increased obligations or additional costs, which could also have a material adverse impact on our cash flows, results of operations or financial condition. See also Notes 5, 10 and 11 of the Notes to Consolidated Financial Statements for further discussion.

Our pension plans are currently underfunded and we may have to make significant cash payments to the plans, reducing the cash available for our business.

We sponsor a qualified non-contributory defined benefit pension plan, which covers substantially all administrative and non-union employees. We currently expect to make voluntary contributions in 2010 of approximately $20 million. If the performance of the assets in our pension plans does not meet our expectations, or if other actuarial assumptions are modified, our contributions could be higher than we expect.

The value of the assets held in our pension plans has been adversely affected by the recent disruptions in the financial markets, and the applicable discount rates applied in determining our pension liabilities have also been negatively affected by the crisis in the financial markets. As a result, as of December 31, 2009, our annual measurement date, our pension plan was underfunded by $55.6 million (based on the actuarial assumptions used in the application of GAAP). Our pension plans are subject to the Employee Retirement Income Security Act of 1974 ("ERISA"). Under ERISA, the Pension Benefit Guaranty Corporation, or PBGC, has the authority to terminate an underfunded pension plan under limited circumstances. In the event our pension plan is terminated for any reason while the plan is underfunded, we will incur a liability to the PBGC that may be equal to the entire amount of the underfunding.

Provisions in our restated certificate of incorporation and restated bylaws, the agreements governing our indebtedness and Delaware law may discourage a takeover attempt even if doing so might be beneficial to our shareholders.

Provisions contained in our restated certificate of incorporation and restated bylaws could impose impediments to the ability of a third-party to acquire us even if a change of control would be beneficial to our shareholders. Provisions of our restated certificate of incorporation and restated bylaws impose various procedural and other requirements, which could make it more difficult for stockholders to effect certain corporate actions. For example, our restated certificate of incorporation authorizes our Board of Directors to determine the rights, preferences, privileges and restrictions of unissued series of preferred stock, without any vote or action by our stockholders. Thus, our Board of Directors can authorize and issue shares of preferred stock with voting or conversion rights that could adversely affect the voting or other rights of holders of Common Stock. We are also subject to provisions of Delaware law that prohibit us from engaging in any business combination with any "interested stockholder," meaning, generally, that a stockholder who beneficially owns more than 15% of Common Stock cannot acquire us for a period of three years from the date this person became an interested stockholder unless various conditions are met, such as approval of the transaction by our Board of Directors. These provisions may have the effect of delaying or deterring a change of control of our Company, and could limit the price that certain investors might be willing to pay in the future for shares of Common Stock.

If a "fundamental change" (as defined in the indenture governing the 3.25% convertible senior notes due 2015 ("3.25% Notes")) occurs, holders of the 3.25% Notes will have the right, at their option, either to convert their 3.25% Notes or require us to repurchase all or a portion of their 3.25% Notes, and holders of the 2.25% convertible senior notes due 2024 ("2.25% Notes") will have the right to require us to repurchase all or a portion of their notes. In the event of a "make-whole fundamental change" (as defined in the indenture governing the 3.25% Notes), we also may be required to increase the conversion rate applicable to any 3.25% Notes surrendered for conversion. In addition, the indentures for the convertible notes prohibit us from engaging in certain mergers or acquisitions unless, among other things, the surviving entity is a U.S. entity that assumes our obligations under the convertible notes. Certain of our debt instruments impose similar restrictions on us, including with respect to mergers or consolidations with other companies and the sale of substantially all of our assets. These provisions could prevent or deter a third-party from acquiring us even where the acquisition could be beneficial to you.

We may not realize all or any of the anticipated benefits from acquisitions we undertake, as acquisitions entail a number of inherent risks.

From time to time we expand our business and reserve position through acquisitions of businesses and assets, mergers, joint ventures or other transactions. Such transactions involve various inherent risks, such as:

- 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, acquisition or other transaction candidates;

- 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 acquisition or other transaction;
- problems that could arise from the integration of the acquired business;
- the risk of obtaining mining permits for acquired coal assets; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying the acquisition or other transaction rationale.

Any one or more of these and other factors could cause us not to realize the benefits anticipated to result from the acquisition of businesses or assets or could result in unexpected liabilities associated with these acquisitions.

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

We rely on customers in other countries for a portion of our sales, with shipments to countries in North America, South America, Europe, Asia and Africa. We compete in these international markets against coal produced in other countries. Coal is sold internationally in United States dollars. As a result, mining costs in competing producing countries may be reduced in United States 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.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our cash flows, results of operations or financial condition.

Our business is affected by general economic conditions, fluctuations in consumer confidence and spending, and market liquidity, which can decline as a result of numerous factors outside of our control, such as terrorist attacks and acts of war. Future terrorist attacks against United States targets, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions affecting customers may materially adversely affect operations. As a result, there could be delays or losses in transportation and deliveries of coal to customers, decreased sales of coal and extension of time for payment of accounts receivable from customers. Strategic targets such as energy-related assets may be at greater risk of future terrorist attacks than other targets in the United States. In addition, such disruption may lead to significant increases in energy prices that could result in government-imposed price controls. It is possible that any, or a combination, of these occurrences could have a material impact on cash flows, results of operations or financial condition.

Coal mining is subject to inherent risks, some for which we maintain third-party insurance and some for which we self-insure.

Our operations are subject to certain events and conditions that could disrupt operations, including fires and explosions, accidental mine water discharges, coal slurry releases and impoundment failures, natural disasters, equipment failures, maintenance problems and flooding. We maintain insurance policies that provide limited coverage for some, but not all, of these risks. Even where insurance coverage applies, there can be no assurance that these risks would be fully covered by insurance policies and insurers may contest their obligations to make payments. Failures by insurers to make payments could have a material adverse effect on our cash flows, results of operations or financial condition. We self-insure our highwall miners and underground equipment, including our longwalls. We do not currently carry business interruption insurance.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We own and lease properties totaling approximately 1 million acres in West Virginia, Kentucky, Virginia, Pennsylvania and Tennessee. In addition, certain of our owned or leased properties are leased or subleased to third-party tenants. Our current practice is to obtain a title review from a licensed attorney prior to purchasing or leasing property. We generally have not obtained title insurance in connection with acquisitions of coal reserves. In some cases, the seller or lessor warrants property title. We have not required title confirmation in certain cases under long-standing lease agreements where we are now the current lessee and the lease covers property where mining has occurred previously. We currently own or lease the equipment that is utilized in mining operations. The following table describes the location and general character of our major existing facilities, exclusive of mines, coal preparation plants and their adjoining offices.

Administrative Offices:

Richmond, Virginia	Owned	Massey Corporate Headquarters
Julian, West Virginia	Owned	Massey Operational Headquarters

For a description of mining properties, see Item 1. Business, under the heading “Mining Operations” and “Coal Reserves.”

Item 3. Legal Proceedings

We are parties to a number of legal proceedings, incident to our normal business activities. These matters include, but are not limited to, contract disputes, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates, we do not believe that any liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition. However, it is reasonably possible that the ultimate liabilities in the future with respect to these lawsuits and claims may be material to our cash flows, results of operations or financial condition.

We are also party to lawsuits and other legal proceedings related to the non-coal businesses previously conducted by Fluor Corporation (renamed Massey Energy Company) but now conducted by New Fluor. Under the terms of the Distribution Agreement entered into by New Fluor and us as of November 30, 2000, in connection with the Spin-Off of New Fluor, New Fluor agreed to indemnify us with respect to all such legal proceedings and has assumed their defense.

Additional legal proceedings required by this Item 3 are contained in Note 18, “Contingencies” to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K, which is incorporated herein by reference.

Part II

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

Common Stock

Common Stock is listed on the New York Stock Exchange (“NYSE”) and trades under the symbol MEE. As of February 15, 2010, there were 86,545,037 shares outstanding and approximately 6,189 shareholders of record of Common Stock.

The following table sets forth the high and low sales prices per share of Common Stock on the NYSE for the past two years, based upon published financial sources, and the dividends declared on each share of Common Stock for the quarter indicated.

	High	Low	Dividends
Fiscal Year 2008			
Quarter ended March 31, 2008	$ 44.00	$ 26.22	$ 0.05
Quarter ended June 30, 2008	$ 95.70	$ 35.33	$ 0.05
Quarter ended September 30, 2008	$ 94.09	$ 31.15	$ 0.05
Quarter ended December 31, 2008	$ 35.00	$ 10.05	$ 0.06
Fiscal Year 2009			
Quarter ended March 31, 2009	$ 18.69	$ 9.62	$ 0.06
Quarter ended June 30, 2009	$ 26.46	$ 9.80	$ 0.06
Quarter ended September 30, 2009	$ 33.51	$ 15.85	$ 0.06
Quarter ended December 31, 2009	$ 44.40	$ 25.52	$ 0.06

Dividends

On February 16, 2010, our Board of Directors declared a dividend of $0.06 per share, payable on March 31, 2010, to shareholders of record on March 17, 2010.

Our current dividend policy anticipates the payment of quarterly dividends in the future. Our Board of Directors increased the regular quarterly dividend to $0.06 per share in the fourth quarter of 2008. The ABL Facility and our 6.875% senior notes due 2013 (the “6.875% Notes”) contain provisions that restrict us from paying dividends in excess of certain amounts. The ABL Facility limits the payment of dividends to $50 million annually on Common Stock. The 6.875% Notes limit the payment of dividends to $25 million annually on Common Stock, plus the availability in the Restricted Payments Baskets (as defined in the Indenture governing the 6.875% Notes). In addition, dividends can be paid only so long as no default exists under the ABL Facility or the 6.875% Notes, as the case may be, or would result thereunder from paying such dividend. There are no other restrictions, other than those set forth under the corporate laws of the State of Delaware, where we are incorporated, on our ability to declare and pay dividends. The declaration and payment of dividends to holders of Common Stock will be at the discretion of the Board of Directors and will be dependent upon our future earnings, financial condition, and capital requirements.

Convertible Debt Securities

Our 2.25% Notes are convertible by holders into shares of Common Stock during certain periods under certain circumstances. None of the 2.25% Notes were eligible for conversion at December 31, 2009. If all of the notes outstanding at December 31, 2009 had been eligible and were converted, we would have been required to issue 287,113 shares of Common Stock. No conversions occurred during the year. See Note 6 to the Notes to Consolidated Financial Statements for further discussion of conversion features of the 2.25% Notes.

Our 3.25% Notes are convertible under certain circumstances and during certain periods into (i) cash, up to the aggregate principal amount of the 3.25% Notes subject to conversion and (ii) cash, Common Stock or a combination thereof, at our election in respect to the remainder (if any) of our conversion obligation. Effective December 31, 2009, the conversion rate has been adjusted to 11.4420 shares of Common Stock per $1,000 principal amount of 3.25% Notes. The adjustment of the conversion rate is a result of us increasing our cash dividend from $0.05 to $0.06 per share of Common Stock in the fourth quarter of 2008. As of December 31, 2009, the price per share of Common Stock had not reached the specified threshold for conversion. No conversions occurred during the year. See Note 6 to the Notes to Consolidated Financial Statements for further discussion of conversion features of the 3.25% Notes.

Repurchase Program

On November 14, 2005, our Board of Directors authorized a stock repurchase program (the "Repurchase Program"), authorizing us to repurchase shares of Common Stock. We may repurchase Common Stock from time to time, as determined by authorized officers, up to an aggregate amount not to exceed $500 million (excluding commissions) with free cash flow as existing financing covenants may permit. Existing covenants currently allow for up to approximately $611 million of share repurchases. As of December 31, 2009, we had $420 million available under the current authorization. The stock repurchases may be conducted on the open market, through privately negotiated transactions, through derivative transactions or through purchases made in accordance with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended ("Exchange Act"), in compliance with the SEC's regulations and other legal requirements. The Repurchase Program does not require us to acquire any specific number of shares and may be terminated at any time. Through December 31, 2009, 2,874,800 shares have been repurchased at an average price of $27.80 per share and classified as Treasury stock. All of the 2,874,800 shares held as Treasury stock were issued as part of the 4,370,000 shares of Common Stock which we publicly offered and sold in August 2008. No additional share repurchases have been made since that time.

The following table summarizes information about shares of Common Stock that were purchased during the fourth quarter of 2009.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plan
October 1 through October 31	-	-	-	-
November 1 through November 30	-	-	-	-
December 1 through December 31	-	-	-	-
Total	-		-	10,903,427 (1)

(1) Calculated using $420 million that may yet be purchased under our share repurchase program and $38.52, the closing price of Common Stock as reported on the New York Stock Exchange on January 31, 2010.

Common Stock Offering Program

On February 3, 2009, pursuant to Rule 424(b)(5), we filed a prospectus supplement with the Securities and Exchange Commission ("SEC") allowing us to sell up to 5.0 million shares of Common Stock from time to time in our discretion. The proceeds from any shares of Common Stock sold will be used for general corporate purposes, which may include funding for acquisitions or investments in business, products, technologies, and repurchases and repayment of our indebtedness. As of January 31, 2010, no shares of Common Stock had been sold pursuant to this program.

Transfer Agent and Registrar

The transfer agent and registrar for Common Stock is American Stock Transfer & Trust Company, LLC, Shareholder Services Group, 6201 15th Avenue, Brooklyn, New York 11219, toll free (800) 813-2847, or if outside the United States at (718) 921-8124.

Item 6. Selected Financial Data

SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2009	2008 As Adjusted [1]	2007	2006	2005
	(In millions, except per share, per ton, and number of employees amounts)				
CONSOLIDATED STATEMENT OF INCOME DATA:					
Produced coal revenue	$ 2,318.5	$ 2,559.9	$ 2,054.4	$ 1,902.3	$ 1,777.7
Total revenue	2,691.2	2,989.8	2,413.5	2,219.9	2,204.3
Income (loss) before interest and income taxes	227.0	128.7	179.7	111.0	(20.9)
Income (loss) before cumulative effect of accounting change	104.4	47.8	94.1	41.6	(101.6)
Net income (loss)	104.4	47.8	94.1	41.0	(101.6)
Income (loss) per share - Basic [2]					
Income (loss) before cumulative effect of accounting change	$ 1.23	$ 0.58	$ 1.17	$ 0.51	$ (1.33)
Net income (loss)	$ 1.23	$ 0.58	$ 1.17	$ 0.50	$ (1.33)
Income (loss) per share - Diluted [2]					
Income (loss) before cumulative effect of accounting change	$ 1.22	$ 0.58	$ 1.17	$ 0.51	$ (1.33)
Net income (loss)	$ 1.22	$ 0.58	$ 1.17	$ 0.50	$ (1.33)
Dividends declared per share	$ 0.24	$ 0.21	$ 0.17	$ 0.16	$ 0.16
CONSOLIDATED BALANCE SHEET DATA:					
Working capital	$ 869.7	$ 731.3	$ 522.6	$ 445.2	$ 670.8
Total assets	3,799.7	3,672.4	2,860.7	2,740.7	2,986.5
Long-term debt	1,295.6	1,310.2	1,102.7	1,102.3	1,102.6
Shareholders' equity [3]	1,256.3	1,126.6	784.0	697.3	841.0
OTHER DATA:					
EBIT [4]	$ 227.0	$ 128.7	$ 179.7	$ 111.0	$ (20.9)
EBITDA [4]	$ 497.2	$ 386.1	$ 425.7	$ 341.5	$ 213.6
Average cash cost per ton sold [5]	$ 50.48	$ 46.65	$ 41.20	$ 40.95	$ 34.00
Produced coal revenue per ton sold	$ 63.26	$ 62.50	$ 51.55	$ 48.71	$ 42.02
Capital expenditures	$ 274.5	$ 736.5	$ 270.5	$ 298.1	$ 346.6
Produced tons sold	36.7	41.0	39.9	39.1	42.3
Tons produced	38.0	41.1	39.5	38.6	43.1
Number of employees	5,851	6,743	5,407	5,517	5,709

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(1) Amounts for the twelve months ended December 31, 2008, have been adjusted in accordance with new accounting guidance related to our 3.25% Notes, effective January 1, 2009. See Note 6 in the Notes to Consolidated Financial Statements for further discussion.

(2) In accordance with GAAP, the effect of certain dilutive securities was excluded from the calculation of the diluted income (loss) per common share for the years ended December 31, 2009, 2008, 2007, 2006, and 2005, as such inclusion would result in antidilution.

(3) Certain accounting pronouncements adopted in 2007 and 2006 affect the comparability of the 2007 and 2006 financial statements to prior years. The adoption of accounting guidance related to income taxes on January 1, 2007 increased equity by $5.2 million. The adoption of accounting guidance related to stripping costs on January 1, 2006 decreased equity by $93.8 million and the adoption of accounting guidance related to pension and other postretirement plans on December 31, 2006 decreased equity by $40.2 million.

(4) EBIT is defined as Income (loss) before interest and taxes. EBITDA is defined as Income (loss) before interest and taxes before deducting Depreciation, depletion, and amortization (“DD&A”). Although neither EBIT nor EBITDA are measures of performance calculated in accordance with GAAP, we believe that both measures are useful to an investor in evaluating us because they are widely used in the coal industry as measures to evaluate a company’s operating performance before debt expense and as a measure of its cash flow. Neither EBIT nor EBITDA purport to represent operating income, net income or cash generated by operating activities and should not be considered in isolation or as a substitute for measures of performance calculated in accordance with GAAP. In addition, because neither EBIT nor EBITDA are calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. The table below reconciles the GAAP measure of Net income (loss) to EBIT and to EBITDA.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
		As Adjusted			
			(In millions)		
Net income (loss)	$ 104.4	$ 47.8	$ 94.1	$ 41.0	$ (101.6)
Cumulative effect of accounting change, net of tax	-	-	-	0.6	-
Income tax expense	32.9	1.1	35.4	3.4	26.2
Net interest expense and loss on short-term investment	89.7	79.8	50.2	66.0	54.5
EBIT	227.0	128.7	179.7	111.0	(20.9)
Depreciation, depletion and amortization	270.2	257.4	246.0	230.5	234.5
EBITDA	$ 497.2	$ 386.1	$ 425.7	$ 341.5	$ 213.6

(5) Average cash cost per ton is calculated as the sum of Cost of produced coal revenue (excluding Selling, general and administrative expense (“SG&A”) and DD&A), divided by the number of produced tons sold. In 2009, in order to conform more closely to common industry reporting practices, we have changed our calculation of cash cost to exclude SG&A expense. This change has been reflected in the presentation of data for both the current and comparative past reporting periods in this report. Although Average cash cost per ton is not a measure of performance calculated in accordance with GAAP, we believe that it is useful to investors in evaluating us because it is widely used in the coal industry as a measure to evaluate a company’s control over its cash costs. Average cash cost per ton should not be considered in isolation or as a substitute for measures of performance in accordance with GAAP. In addition, because Average cash cost per ton is not calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. The table below reconciles the GAAP measure of Total costs and expenses to Average cash cost per ton.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
		As Adjusted			
		(In millions, except per ton amounts)			
Total costs and expenses	$ 2,464.2	$ 2,861.1	$ 2,233.8	$ 2,108.8	$ 2,225.2
Less: Freight and handling costs	218.2	306.4	167.6	156.5	150.9
Less: Cost of purchased coal revenue	57.1	28.5	95.2	62.6	112.6
Less: Depreciation, depletion and amortization	270.2	257.4	246.0	230.5	234.5
Less: Selling, general and administrative	97.4	77.0	75.8	53.8	68.3
Less: Other expense	8.7	3.2	7.3	6.2	8.0
Less: Litigation charge	-	250.1	-	-	-
Less: Loss on financing transactions	0.2	5.0	-	-	212.4
Less: (Gain) loss on derivative instruments	(37.6)	22.6	-	-	-
Average cash cost	$ 1,850.0	$ 1,910.9 (1)	$ 1,641.9 (1)	$ 1,599.2 (1)	$ 1,438.5 (1)
Average cash cost per ton	$ 50.48	$ 46.65 (1)	$ 41.20 (1)	$ 40.95 (1)	$ 34.00 (1)

(1) Restated Average cash cost and Average cash cost per ton as described in Note 5 above.

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

The following Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") is intended to help the reader understand Massey Energy Company, our operations and our present business environment. MD&A is provided as a supplement to, and should be read in conjunction with, our consolidated financial statements and the accompanying notes thereto contained in Item 8 of this report. From time to time, we may make statements that may constitute "forward-looking statements" within the meaning of the "safe-harbor" provisions of the Private Securities Litigation Reform Act of 1995. These statements are based on our then current expectations and are subject to a number of risks and uncertainties that could cause actual results to differ materially from those addressed in the forward-looking statements. Please see "Forward-Looking Statements" on page i hereto and are incorporated herein and the risk factors that may cause such a difference, which are set forth in Item 1A. Risk Factors and are incorporated herein.

Executive Overview

We operate coal mines and processing facilities in Central Appalachia, which generate revenues and cash flow through the mining, processing and selling of steam and metallurgical grade coal, primarily of low sulfur content. We also generate income and cash flow through other coal-related businesses. Other revenue is obtained from royalties, rentals, gas well revenues, gains on the sale of non-strategic assets and miscellaneous income.

We reported net income for the year ended December 31, 2009 of $104.4 million, or $1.22 per diluted share, compared to net income for 2008 of $47.8 million, or $0.58 per diluted share. Net income in 2009 included pre-tax gains totaling $33.6 million for the sale and exchange of coal reserve interests and other assets with third-parties and a net gain of $37.6 million on certain coal contracts that do not qualify for the normal purchase normal sale ("NPNS") exception. Net income in 2008 included pre-tax charges of $250.1 million related to the litigation with Wheeling-Pittsburgh Steel Corporation ("Wheeling-Pittsburgh"), pre-tax gains totaling $32.4 million related to asset and reserve exchanges with third-parties and a $22.6 million non-cash pre-tax charge to recognize the net unrealized losses on certain coal contracts that do not qualify for the NPNS exception.

During 2009, we completed several coal reserve trades and acquisitions that increased our total reserve base. These transactions, in addition to adjustments made in conjunction with normal annual review and re-evaluation of reserves, and offset by 38 million tons of coal produced, resulted in a net increase of 72 million tons of coal reserves during the year. Following this increase, we estimate that we had 2.4 billion tons of proven and probable coal reserves at December 31, 2009.

On August 27, 2009, a fire destroyed the Bandmill preparation plant at our Logan County resource group, located near Logan, West Virginia. This incident impacted the operations at Logan County and, to a lesser extent, our operations as a whole during the second half of 2009. Efforts to replace production at our other locations to help mitigate the effects of the fire, including meeting customer commitments, are ongoing. We maintain property insurance which is expected to cover property losses incurred from the fire. We received $15.4 million in insurance proceeds during 2009. A replacement preparation plant is currently under construction, which is expected to be operational by the fall of 2010.

Produced tons sold were 36.7 million in 2009, compared to 41.0 million in 2008. We produced 38.0 million and 41.1 million tons in 2009 and 2008, respectively. The lower coal production in 2009 was primarily the result of the idling of higher cost mines and the reduction of hours worked, mainly overtime and weekend shifts, in response to lower demand. Exports decreased from 8.1 million tons in 2008 to 5.7 million tons in 2009. Increasing coal stockpiles due to utilities shifting to gas fired generation and weak demand for electric power generation and steel production in both domestic and international markets has created challenges among our customer base to accept shipments of coal according to contracted schedules. We are working with our customers to modify shipment schedules and amend contract terms where necessary or appropriate, which may affect our revenues and margins in future periods.

During 2009, Produced coal revenue decreased by 9% compared to 2008, reflecting lower shipments in 2009. Our average Produced coal revenue per ton sold in 2009 increased to $63.26 compared to $62.50 in 2008. Our average Produced coal revenue per ton in 2009 for metallurgical tons sold decreased by 1% to $95.93 from $97.07 in 2008. The average per ton sales price for utility and industrial coal was higher in 2009 compared to 2008, attributable to prices contracted during prior periods when demand and pricing were elevated for these grades of coal in the United States.

Our Average cash cost per ton sold was $50.48 in 2009, compared to $46.65 in 2008. The increased cost level is primarily due to higher fixed cost absorption on lower volume shipped, higher labor costs, and higher equipment rental costs. In response to the current difficult market conditions, we have taken certain actions to reduce overall costs including the idling of several higher cost mines, limitation of overtime, selective general and administrative cost reductions, renegotiation of supply contracts and the implementation of significant wage and benefit reductions beginning on May 1, 2009.

While certain general business conditions appear to be improving, the recent recession, credit crisis and related turmoil in the global financial system has had and may continue to have a negative impact on our business, financial condition and liquidity. We may face significant future challenges if conditions in the financial markets do not continue to improve. Worldwide demand for coal has been adversely impacted by the recent global recession. Demand for metallurgical coal has been disproportionately affected as most steel producers responded to the recent recession by significantly reducing production levels. This, in turn, has led to lower sales volumes and a number requests from our customers for the deferral of contracted shipments. These conditions have negatively impacted our revenues. Additionally, the volatility and disruption of financial markets has and could continue to affect the creditworthiness of our customers and/or limit our customers' ability to obtain adequate financing to maintain operations. This could result in a further decrease in sales volume that could have a further negative impact on our cash flows, results of operations or financial condition.

The steel industry and the global metallurgical coal markets have shown recent signs of improvement. Several steel producers have announced plans to restart idled blast furnaces and production capacity utilization rates have begun to increase. The timing of any improvement is uncertain but if these trends continue, it could have a positive impact on metallurgical coal demand and improve our opportunities to sell our metallurgical coal.

Results of Operations

2009 Compared with 2008

Revenues

(In thousands)	Year Ended December 31, 2009	Year Ended December 31, 2008	Increase (Decrease)	% Increase (Decrease)
Revenues				
Produced coal revenue	$ 2,318,489	$ 2,559,929	$ (241,440)	(9%)
Freight and handling revenue	218,203	306,397	(88,194)	(29%)
Purchased coal revenue	62,721	30,684	32,037	104%
Other revenue	91,746	92,779	(1,033)	(1%)
Total revenues	$ 2,691,159	$ 2,989,789	$ (298,630)	(10%)

The following is a breakdown, by market served, of the changes in produced tons sold and average produced coal revenue per ton sold for 2009 compared to 2008:

(In millions, except per ton amounts)	Year Ended December 31, 2009	Year Ended December 31, 2008	Increase (Decrease)	% Increase (Decrease)
Produced tons sold:				
Utility	26.6	27.0	(0.4)	(1%)
Metallurgical	7.4	9.9	(2.5)	(25%)
Industrial	2.7	4.1	(1.4)	(34%)
Total	36.7	41.0	(4.3)	(10%)
Produced coal revenue per ton sold:				
Utility	$ 53.69	$ 49.92	$ 3.77	8%
Metallurgical	95.93	97.07	(1.14)	(1%)
Industrial	68.33	61.78	6.55	11%
Weighted average	63.26	62.50	0.76	1%

Shipments of all grades of coal decreased in 2009, compared to 2008, due to lower customer demand, as the United States and world economies suffered through a severe recession during 2009. Demand for utility coal was also negatively affected by increasing coal stockpiles due to utilities shifting to gas fired generation. The average per ton sales price for industrial and utility coal was higher in 2009, compared to 2008, attributable to prices contracted during periods when demand and pricing were elevated for all grades of coal in the United States.

Freight and handling revenue decreased due to a reduction in the number of contracts in which customers were required to pay freight in 2009, compared to 2008, and by a decrease in export tons sold from 8.1 million in 2008, to 5.7 million in 2009.

Purchased coal revenue increased in 2009, compared to 2008, as a result of 0.5 million tons increase in the number of purchased tons shipped.

Other revenue includes refunds on railroad agreements, royalties related to coal lease agreements, gas well revenue, gains on the sale of non-strategic assets and reserve exchanges, joint venture revenue and other miscellaneous revenue. Other revenue for 2009 includes pre-tax gains of $26.5 million on the exchange of coal reserves and other assets, and $7.1 million for the sale of our interest in certain coal reserves. Other revenue for 2008 includes a pre-tax gain of $32.4 million on the exchange of coal reserves (see Note 4 in the Notes to Consolidated Financial Statements for further discussion).

Costs

	Year Ended December 31,			
(In thousands)	2009	2008	Increase (Decrease)	% Increase (Decrease)
Costs and expenses				
Cost of produced coal revenue	$ 1,850,058	$ 1,910,953	$ (60,895)	(3%)
Freight and handling costs	218,203	306,397	(88,194)	(29%)
Cost of purchased coal revenue	57,108	28,517	28,591	100%
Depreciation, depletion and amortization, applicable to:				
Cost of produced coal revenue	268,317	253,737	14,580	6%
Selling, general and administrative	1,860	3,590	(1,730)	(48%)
Selling, general and administrative	97,381	77,015	20,366	26%
Other expense	8,705	3,207	5,498	171%
Litigation charge	-	250,061	(250,061)	(100%)
Loss on financing transactions	189	5,006	(4,817)	(96%)
(Gain) loss on derivative instruments	(37,638)	22,552	(60,190)	(267%)
Total costs and expenses	$ 2,464,183	$ 2,861,035	$ (396,852)	(14%)

Cost of produced coal revenue decreased due to fewer tons sold in 2009, compared to 2008, offset by increased productions costs, higher labor costs, and higher equipment rental costs.

Freight and handling costs decreased due to a reduction in the number of contracts in which customers were required to pay freight in 2009, compared to 2008, and by a decrease in export tons sold from 8.1 million in 2008, to 5.7 million in 2009.

Costs of purchased coal revenue increased in 2009, compared to 2008, as a result of 0.5 million tons increase in the number of purchased tons shipped, offset by a decrease due to a $7.6 million black lung excise tax refund recorded in 2009.

Depreciation, depletion and amortization applicable to Cost of produced coal revenue increased due to impact of various of our capital projects that went into service during 2008.

Selling, general and administrative expense increased in 2009, compared to 2008, primarily due to an increase in stock-based compensation accruals in 2009, caused by an increase in our stock price during 2009 as compared to 2008.

Other expense includes a $6.0 million reserve for bad debt for 2009 related to a note receivable from a supplier.

Litigation charge represents an accrual for a specific legal action related to the litigation with Wheeling-Pittsburgh that was recorded in 2008.

Loss on financing transactions in 2009, relates to the $0.2 million loss recognized from the purchase of $11.9 million of our 3.25% Notes on the open market. Loss on financing transactions in 2008, relates to a $4.1 million gain recognized from the purchase of $19.0 million of our 3.25% Notes on the open market during the fourth quarter of 2008, offset by a $9.1

million of fees incurred for the tender offer on our 6.625% Notes during the third quarter of 2008. See Note 6 in the Notes to Consolidated Financial Statements for further discussion.

(Gain) loss on derivative instruments represents a net gain of $37.6 million ($53.1 million of unrealized gains due to fair value measurement adjustments and $15.5 million of realized losses due to settlements on existing contracts) related to purchase and sales contracts that did not qualify for the NPNS exception in 2009 (see Note 15 in the Notes to Consolidated Financial Statements for further discussion).

Interest

Interest income decreased in 2009, compared to 2008, primarily as a result of a significant reduction in the interest rates earned on our interest bearing investments. During 2009 and 2008, we recorded $8.7 million and $7.0 million, respectively, of interest income on black lung excise tax refunds.

Interest expense increased primarily as a result of $18.4 million in 2009, compared to $6.9 million in 2008, of non-cash interest expense for the amortization of the discount recorded on our 3.25% Notes. Additionally, interest expense for 2008 includes $1.9 million (pre-tax) for the write-off of unamortized financing fees and $4.2 million for the write-off of unamortized interest rate swap termination payment (see Note 6 in the Notes to Consolidated Financial Statements for further discussion).

Loss on short-term investment

Loss on short-term investment represents a *pro rata* share of the estimated loss in our investment in the Primary Fund of $6.5 million (see Note 16 to the Notes to Consolidated Financial Statements for further discussion).

Income Taxes

Income tax expense was $32.9 million for 2009, compared with a tax expense of $1.1 million for 2008. The income tax rates for 2009 and 2008 were favorably impacted by percentage depletion allowances and the usage of net operating loss carryforwards. The income tax rate in 2009 and 2008 was negatively impacted by nondeductible penalties. Also impacting the 2009 and 2008 income tax rate were favorable adjustments in connection with the election to forego bonus depreciation and claim a refund for alternative minimum tax credits. Because of the discrete tax events occurring in 2009, the tax rate for 2009 may not be indicative of future tax rates. The income tax rate in 2008 was negatively impacted by a nondeductible EPA settlement and an increase in deferred tax asset valuation allowances related principally to federal net operating losses. The 2008 rate was also favorably impacted by the adjustment of reserves in connection with the closing of a prior period audit by the IRS.

2008 Compared with 2007

Revenues

	Year Ended December 31,			
(In thousands)	2008	2007	Increase (Decrease)	% Increase (Decrease)
Revenues				
Produced coal revenue	$ 2,559,929	$ 2,054,413	$ 505,516	25
Freight and handling revenue	306,397	167,641	138,756	83
Purchased coal revenue	30,684	108,191	(77,507)	(72%)
Other revenue	92,779	83,278	9,501	(8%)
Total revenues	$ 2,989,789	$ 2,413,523	$ 576,266	24%

The following is a breakdown, by market served, of the changes in produced tons sold and average produced coal revenue per ton sold for 2008 compared to 2007:

(In millions, except per ton amounts)	Year Ended December 31, 2008	2007	Increase (Decrease)	% Increase (Decrease)
Produced tons sold:				
Utility	27.0	27.4	(0.4)	(1%)
Metallurgical	9.9	8.5	1.4	16%
Industrial	4.1	4.0	0.1	2%
Total	41.0	39.9	1.1	3%
Produced coal revenue per ton sold:				
Utility	$ 49.92	$ 45.18	$ 4.74	10%
Metallurgical	97.07	72.49	24.58	34%
Industrial	61.78	50.82	10.96	22%
Weighted average	62.50	51.55	10.95	21%

Shipments of metallurgical coal increased in 2008, compared to 2007, as demand for this type of coal, especially in the export market, increased during 2008, allowing certain quality coal to be shifted from the utility to the metallurgical market. Production increased as new mines were started in 2008 as part of our expansion plan. The average per ton sales price for utility coal continued to improve in 2008, attributable to prices contracted during a period of increased demand for utility coal in the United States. The higher demand resulted in shortages of certain quality utility coal, increasing the market prices of this coal, and allowing us to negotiate agreements containing higher-priced terms as lower-priced contracts expired.

Freight and handling revenue increased due to an increase in export tons sold from 4.8 million tons in 2007 to 8.1 million tons in 2008. In addition, during 2008 there was a significant increase in freight rates, including fuel surcharges during a large portion of the year.

Purchased coal revenue decreased mainly due to a decrease in purchased tons sold from 2.1 million in 2007 to 0.5 million in 2008.

Other revenue includes refunds on railroad agreements, royalties related to coal lease agreements, gas well revenue, gains on the sale of non-strategic assets and reserve exchanges, joint venture revenue and other miscellaneous revenue. Other revenue for 2008 includes a pre-tax gain of $32.4 million on an exchange of coal reserves and other assets. In addition, railroad refund income was higher in 2008 than in 2007, offset by lower royalty earnings in 2008 compared to 2007. Other revenue for 2007 includes a pre-tax gain of $10.3 million on an exchange of coal reserves and $6.7 million on the sale of mineral rights override (see Note 4 in the Notes to Consolidated Financial Statements for further discussion).

Costs

(In thousands)	2008 As Adjusted	2007	Increase (Decrease)	% Increase (Decrease)
Costs and expenses				
Cost of produced coal revenue	$ 1,910,953	$ 1,641,774	$ 269,179	16%
Freight and handling costs	306,397	167,641	138,756	83%
Cost of purchased coal revenue	28,517	95,241	(66,724)	(70%)
Depreciation, depletion and amortization, applicable to:				
Cost of produced coal revenue	253,737	242,755	10,982	5%
Selling, general and administrative	3,590	3,280	310	9%
Selling, general and administrative	77,015	75,845	1,170	2%
Other expense	3,207	7,308	(4,101)	(56%)
Litigation charge	250,061	-	250,061	100%
Loss on financing transactions	5,006	-	5,006	100%
(Gain) loss on derivative instruments	22,552	-	22,552	100%
Total costs and expenses	$ 2,861,035	$ 2,233,844	$ 627,191	28%

Cost of produced coal revenue increased due to increased sales-related costs on higher produced coal revenues including production royalties and severance taxes, increased supplies costs including diesel fuel and explosives, higher labor costs, litigation settlements and higher indirect costs associated with compliance with new safety regulations. Supplies costs increased both due to a commodity driven inflationary increase and overall usage as the volume of produced tons sold increased from 39.9 million tons in 2007 to 41.0 million tons in 2008.

Freight and handling costs increased due to an increase in export tons sold from 4.8 million tons in 2007 to 8.1 million tons in 2008. In addition, during 2008 there was a significant increase in freight rates, including fuel surcharges during a large portion of the year.

Cost of purchased coal revenue decreased due to a decrease in purchased tons sold from 2.1 million in 2007 to 0.5 million in 2008.

Depreciation, depletion and amortization applicable to Cost of produced coal revenue increased due to impact of various of our capital projects which went into service during 2008.

Litigation charge represents the court award and associated interest for the Wheeling-Pittsburgh matter.

Loss on financing transactions relates to $9.1 million fees incurred for the tender offer for our 6.625% senior notes due 2010 (the "6.625% Notes"), offset by a $4.1.million gain recognized from the purchase of $19.0 million of our 3.25% Notes on the open market during 2008 (see Note 6 in the Notes to Consolidated Financial Statements for further discussion).

(Gain) loss on derivative instruments represents net unrealized losses of $22.6 million related to purchase and sales contracts that did not qualify for the NPNS exception in 2008 (see Note 15 in the Notes to Consolidated Financial Statements for further discussion).

Interest

Interest income in 2008 was comparable to the prior year at $23.6 million as the decline during 2008 in interest rates earned on our interest bearing investments was offset by higher cash balances on hand from August 2008 onward due to the debt and equity issuances in the third quarter of 2008 and the recording of $7.0 million of interest income from black lung excise tax refunds in 2008.

Interest expense was higher in 2008 compared to 2007, primarily due to: 1) a credit to interest expense in 2007 of $11.4 million relating to the reversal of interest accrued on the Harman matter, which was overturned by the WV Supreme Court in 2007 (see Note 18 in the Notes to Consolidated Financial Statements for further discussion), 2) $6.9 million of non-cash interest expense in 2008 for the amortization of the discount recorded on our 3.25% Notes, and 3) $6.1 million in interest expense in 2008 for the write-off of debt issuance costs and the related interest rate swap balance due to the repurchase of the 6.625% Notes (see Note 6 in the Notes to Consolidated Financial Statements for further discussion).

Loss on short-term investment

Loss on short-term investment represents a *pro rata* share of the estimated loss in our investment in the Primary Fund of $6.5 million (see Note 16 to the Notes to Consolidated Financial Statements for further discussion).

Income Taxes

Income tax expense was $1.1 million for 2008, compared with a tax expense of $35.4 million for 2007. The income tax rates for 2008 and 2007 were favorably impacted by percentage depletion allowances and the usage of net operating loss carryforwards. The income tax rate in 2008 was negatively impacted by nondeductible penalties and an increase in deferred tax asset valuation allowances related principally to federal net operating losses. Also impacting the 2008 income tax rate were favorable adjustments in connection with the election to forego bonus depreciation and claim a refund for alternative minimum tax credits. The income tax rate in 2007 was negatively impacted by a nondeductible EPA settlement and an increase in deferred tax asset valuation allowances related principally to federal net operating losses. The 2007 rate was also favorably impacted by the adjustment of reserves in connection with the closing of a prior period audit by the IRS.

Liquidity and Capital Resources

At December 31, 2009, our available liquidity was $764.2 million, comprised of Cash and cash equivalents of $665.8 million and $98.4 million of availability from our ABL. We also had a $10.9 million investment in the Primary Fund, which was recorded in Short-term investment. During January 2010, subsequent to the balance sheet date, we received a distribution in the amount of $14.6 million from the Primary Fund (see Note 16 in the Notes to Consolidated Financial Statements for further discussion). Our total debt-to-book capitalization ratio was 51.2% at December 31, 2009.

Debt was comprised of the following:

	December 31, 2009	December 31, 2008 As Adjusted
	(In Thousands)	
6.875% senior notes due 2013, net of discount	$ 756,727	$ 756,041
3.25% convertible senior notes due 2015, net of discount	526,435	517,538
6.625% senior notes due 2010	21,949	21,949
2.25% convertible senior notes due 2024	9,647	9,647
4.75% convertible senior notes due 2023	-	70
Capital lease obligations	4,328	6,912
Total debt	1,319,086	1,312,157
Amounts due within one year	(23,531)	(1,976)
Total long-term debt	$ 1,295,555	$ 1,310,181

See Note 6 in the Notes to Consolidated Financial Statements for further discussion of our debt and debt-related covenants.

Convertible Debt Securities

On January 1, 2009, new accounting guidance became effective relating to our 3.25% Notes, which was retroactively applied, as required. We separately account for the liability and equity components in a manner reflective of our nonconvertible debt borrowing rate, which was determined to be 7.75% at the date of issuance of the 3.25% Notes. The discount associated with the 3.25% Notes is being amortized via the effective-interest method increasing the reported liability until the notes are carried at par value on their maturity date. We recognized $18.4 million and $6.9 million of non-cash interest expense for the amortization of the discount for the twelve months ended December 31, 2009 and 2008, respectively.

3.25% Notes

In November 2009, we concluded an open market purchase, retiring $11.9 million of principal amount of the 3.25% Notes at a cost of $10.0 million, plus accrued interest of $0.1 million. The retirement also resulted in write-offs of $2.4 million of debt discount and $0.3 million of equity component, resulting in a loss of $0.2 million in Loss on financing transactions. Depending on market conditions and covenant restrictions, we may continue to make debt repurchases from time to time through open market purchases, private transactions or otherwise.

4.75% Notes

During May 2009, we redeemed at par the remaining $70,000 of the 4.75% Notes.

6.625% Notes

During January 2010, subsequent to the balance sheet date, we redeemed at par the remaining $21.9 million of the 6.625% Notes.

Asset-Based Credit Facility

We maintain an asset-based revolving credit agreement, the ABL Facility, which provides for available borrowings, including letters of credit, of up to $175 million, depending on the level of eligible inventory and accounts receivable. As of December 31, 2009, we had $98.4 million of availability from our asset-based revolving credit facility. The ABL Facility expires on August 15, 2011.

Debt Ratings

Moody's Investors Service ("Moody's") and Standard & Poor's Rating Services ("S&P") rate our long-term debt. As of January 31, 2010, the outlook for both our S&P and Moody's ratings was Stable.

Current Ratings:	Moody's	S&P
6.875% Notes	B2	BB-
3.25% Notes	B2	BB-
2.25% Notes	B2	BB-

Cash Flow

Net cash provided by operating activities was $288.9 million for 2009, compared to $385.1 million for 2008. Cash provided by operating activities reflects Net income adjusted for non-cash charges and changes in working capital requirements. During 2009, we posted $72.0 million of cash as collateral for an appeal bond in the Harman litigation (see Note 18 to the Notes to Consolidated Financial Statements for more information) which is included in Other current assets as of December 31, 2009.

Net cash utilized by investing activities was $211.6 million and $776.5 million for 2009 and 2008, respectively. The cash used in investing activities reflects capital expenditures in the amount of $274.6 million and $736.5 million for 2009 and 2008, respectively. These capital expenditures are for replacement of mining equipment, the expansion of mining and shipping capacity, and projects to improve the efficiency of mining operations. Additionally, 2009 and 2008 included $19.0 million and $6.0 million, respectively, of proceeds provided by the sale of assets (see Note 4 to the Notes to Consolidated Financial Statements for further discussion).

Net cash utilized by financing activities was $18.5 million for 2009, compared to net cash provided by financing activities of $633.2 million for 2008. Financing activities reflect changes in debt levels, common stock offerings, exercising of stock options, payments of dividends and cash receipts generated from sale-leaseback transactions. Financing activities for 2009 primarily reflects $10.0 million utilized for the purchase of our 3.25% Notes on the open market. Financing activities for 2008 primarily reflects the $674.1 million of proceeds provided by the issuance of the 3.25% Notes, $258.2 million of proceeds provided by the issuance of Common Stock, $322.1 million utilized for the tender payment for the 6.625% Notes, and the $10.4 million utilized for the purchase of our 3.25% Notes on the open market.

We believe that cash on hand, cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, scheduled debt payments, potential share repurchases and debt repurchases, anticipated dividend payments, expected settlements and final awards of outstanding litigation and anticipated capital expenditures (other than major acquisitions) for at least the next twelve months. Nevertheless, our ability to satisfy our debt service obligations, repurchase shares and debt, pay dividends, pay settlements and final awards of outstanding litigation, or fund planned capital expenditures will substantially depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry, debt covenants and financial, business and other factors, some of which are beyond our control.

(See also "Concentration of Credit Risk and Major Customers" in Note 14 in the Notes to Consolidated Financial Statements.) We frequently evaluate potential acquisitions. In the past, we have funded acquisitions primarily with cash generated from operations. As a result of the cash needs we have described above and possible acquisition opportunities, in the future we may consider a variety of financing sources, including debt or equity financing. Currently, other than our ABL, we have no commitments for any additional financing. We cannot be certain that we can obtain additional financing on terms that we find acceptable, if at all, through the issuance of equity securities or the incurrence of additional debt. Additional equity financing may dilute our stockholders, and debt financing, if available, may, among other things, restrict our ability to repurchase Common Stock, declare and pay dividends and raise future capital. If we are unable to obtain additional needed financing, it may prohibit us from making acquisitions, capital expenditures and/or investments, which could materially and adversely affect our prospects for long-term growth.

Common Stock Offering Program

On February 3, 2009, pursuant to Rule 424(b)(5), we filed a prospectus supplement with the Securities and Exchange Commission ("SEC") allowing us to sell up to 5.0 million shares of Common Stock from time to time in our discretion. The proceeds from any shares of Common Stock sold will be used for general corporate purposes, which may include funding for acquisitions or investments in business, products, technologies, and repurchases and repayment of our indebtedness. As of January 31, 2010, no shares of Common Stock had been sold pursuant to this program.

Share Repurchases

The Board of Directors has authorized a total of $500 million (excluding commissions) to repurchase our Common Stock under our share repurchase program. Through December 31, 2009, 2,874,800 shares have been repurchased at an average price of $27.80 per share and classified as Treasury stock. All of the 2,874,800 shares held as Treasury stock were re-issued as part of the 4,370,000 shares of Common Stock which were offered and sold in an underwritten public offering in August 2008. No additional share repurchases have been made since that time. As of December 31, 2009, we had $420 million available under the current authorization. We may repurchase shares of Common Stock from time to time in compliance with the SEC's regulations and other legal requirements, and subject to market conditions and other factors. The share repurchase program does not require us to acquire any specific number of shares and may be terminated at any time.

Contractual Obligations

We have various contractual obligations that are recorded as liabilities within the Consolidated Financial Statements in this Annual Report on Form 10-K. Other obligations, such as certain purchase commitments, operating lease agreements, and other executory contracts are not recognized as liabilities within the Consolidated Financial Statements but are required to be disclosed. The following table is a summary of our significant obligations as of December 31, 2009 and the future periods in which such obligations are expected to be settled in cash. The table does not include current liabilities accrued within the Consolidated Financial Statements, such as Accounts payable and Payroll and employee benefits.

	Payments Due by Period (In Thousands)				
	Total	**Within 1 Year**	**1-3 Years**	**3-5 Years**	**Beyond 5 Years**
Long-term debt [1]	$ 1,784,580	$ 96,018	$ 147,773	$ 855,523	$ 685,266
Capital lease obligations [2]	4,569	1,759	2,740	70	-
Operating lease obligations [3]	252,452	75,412	119,304	50,135	7,601
Coal lease obligations [4]	134,602	18,835	31,280	26,406	58,081
Purchased coal obligations [5]	59,250	59,250	-	-	-
Other purchase obligations [6]	167,985	126,614	32,617	8,754	-
Total Obligations	$ 2,403,438	$ 377,888	$ 333,714	$ 940,888	$ 750,948

(1) Long-term debt obligations reflect the future interest and principal payments of our fixed rate senior unsecured notes outstanding as of December 31, 2009. See Note 6 to the Notes to Consolidated Financial Statements for additional information.

(2) Capital lease obligations include the amount of imputed interest over the terms of the leases. See Note 13 to the Notes to Consolidated Financial Statements for additional information.

(3) See Note 13 to the Notes to Consolidated Financial Statements for additional information.

(4) Coal lease obligations include minimum royalties paid on leased coal rights. Certain coal leases do not have set expiration dates but extend until completion of mining of all merchantable and mineable coal reserves. For purposes of this table, we have generally assumed that minimum royalties on such leases will be paid for a period of 20 years.

(5) Purchased coal obligations represent commitments to purchase coal from external production sources under firm contracts as of December 31, 2009.

(6) Other purchase obligations primarily include capital expenditure commitments for surface mining and other equipment as well as purchases of materials and supplies. We have purchase agreements with vendors for most types of operating expenses. However, our open purchase orders (which are not recognized as a liability until the purchased items are received) under these purchase agreements, combined with any other open purchase orders, are not material and are excluded from this table. Other purchase obligations also include contractual commitments under transportation contracts. Since the actual tons to be shipped under these contracts are not set and will vary, the amount included in the table reflects the minimum payment obligations required by the contracts.

Additionally, we have liabilities relating to pension and other postretirement benefits, work related injuries and illnesses, and mi reclamation and closure. As of December 31, 2009, payments related to these items are estimated to be:

Payments Due by Years (In Thousands)		
Within 1 Year	**1 - 3 Years**	**3 - 5 Years**
$ 81,478	$ 132,072	$ 136,269

Our determination of these noncurrent liabilities is calculated annually and is based on several assumptions, including then-prevailing conditions, which may change from year to year. In any year, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. Moreover, in particular for periods after 2009, the estimates may change from the amounts included in the table, and may change significantly, if assumptions change to reflect changing conditions. These assumptions are discussed in the Notes to Consolidated Financial Statements and in Critical Accounting Estimates and Assumptions of this Management's Discussion and Analysis of Financial Condition and Results of Operations section.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements including guarantees, operating leases, indemnifications, and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in the consolidated balance sheets, and, except for the operating leases, which are discussed in Note 13 to the Notes to Consolidated Financial Statements, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

From time to time we use bank letters of credit to secure our obligations for workers' compensation programs, various insurance contracts and other obligations. At December 31, 2009, we had $121.6 million of letters of credit outstanding of which $45.1 million was collateralized by $46.0 million of cash deposited in restricted, interest bearing accounts pledged to issuing banks and $76.5 million was issued under our asset based lending arrangement. No claims were outstanding against those letters of credit as of December 31, 2009.

We use surety bonds to secure reclamation, workers' compensation, wage payments and other miscellaneous obligations. As of December 31, 2009, we had $401.1 million of outstanding surety bonds. These bonds were in place to secure obligations as follows: post-mining reclamation bonds of $315.6 million, an appeal bond of $72.0 million of cash as collateral in the Harman litigation (see Note 18 to the Notes to Consolidated Financial Statements for more information), and other miscellaneous obligation bonds of $13.5 million. Outstanding surety bonds of $46.1 million are secured with letters of credit.

Generally, the availability and market terms of surety bonds continue to be challenging. If we are unable to meet certain financial tests applicable to some of our surety bonds, or to the extent that surety bonds otherwise become unavailable, we would need to replace the surety bonds or seek to secure them with letters of credit, cash deposits, or other suitable forms of collateral.

Certain Trends and Uncertainties

Our inability to satisfy contractual obligations may adversely affect profitability.

From time to time, we have disputes with customers over the provisions of sales agreements relating to, among other things, coal pricing, quality, quantity, delays and force majeure declarations. Our inability to satisfy contractual obligations could result in the purchase of coal from third-party sources to satisfy those obligations, the negotiation of settlements with customers, which may include price reductions, the reduction of commitments or the extension of the time for delivery, and customers terminating contracts, declining to do future business with us, or initiating claims against us. A few of our customers have notified us of losses they have allegedly incurred due to alleged shortfalls in contracted coal shipments. We believe that factors beyond our control or responsibility account for most or all of the shortfalls. However, we may not be able to resolve all of these disputes, or other disputes with customers over sales agreements, in a satisfactory manner, which could result in the payment of substantial damages or otherwise harm our reputation and our relationships with our customers (see Note 18 to the Notes to Consolidated Financial Statements for further discussion).

The global financial crisis may have an impact on our business, financial condition and liquidity in ways that we currently cannot predict.

The continuing credit crisis and related turmoil in the global financial markets, which has begun to ease in recent months, has had and may continue to have an impact on our business, financial condition and liquidity.

The current difficult economic market environment has caused contraction in the availability of credit in the marketplace. In addition to the impact that the global financial crisis has already had on us, we may face significant challenges if conditions in the financial markets do not continue to improve or worsen. In addition, our ability to access the capital markets may be severely restricted at a time when we would like, or need, to access these markets, which could have an impact on our flexibility to react to changing economic and business conditions and could potentially reduce our sources of liquidity. Moreover, volatility and disruption of financial markets could limit our customers' ability to obtain adequate financing to maintain operations and result in a decrease in sales volume that could have a negative impact on our cash flows, results of operations or financial condition.

Capital and credit market volatility may affect our costs of borrowing.

While we maintain business relationships with a diverse group of financial institutions, their continued viability is not certain. Difficulties at one or more such financial institutions could lead them not to honor their contractual credit commitments under our ABL Facility or to renew their extensions of credit or provide new sources of credit. Recently, the capital and credit markets have been highly volatile as a result of adverse conditions that have caused the failure and near failure of a number of large financial services companies. If the capital and credit markets continue to experience volatility and the availability of funds remains limited, we may incur increased costs associated with borrowings. While we believe that recent governmental and regulatory actions should reduce the risk of a further deterioration or systemic contraction of capital and credit markets, there can be no certainty that our liquidity will not be negatively impacted by adverse conditions in the capital and credit markets.

We may be adversely affected by a decline in the financial condition and creditworthiness of our customers.

In an effort to mitigate credit-related risks in all customer classifications, we maintain a credit policy, which requires scheduled reviews of customer creditworthiness and continuous monitoring of customer news events that might have an impact on their financial condition. Negative credit performance or other events may trigger the application of tighter terms of sale, requirements for collateral or guaranties or, ultimately, a suspension of credit privileges. The creditworthiness of customers can limit who we can do business with and at what price. For the year ended December 31, 2009, approximately 99% of coal sales volume was pursuant to long-term contracts. We anticipate that in 2010, the percentage of our sales pursuant to long-term contracts will be comparable with the percentage of our sales for 2009. For 2010, approximately 50% of our projected sales tons are contracted to be sold to our 10 largest customers. Many of our customers, including many of our large customers, experienced lower demand and weaker financial performance due to the recent economic downturn. If one or more of our larger customers fails to make payment for our sales to them, there could be an adverse effect on our cash flows, results of operations or financial condition.

We have contracts to supply coal to energy trading and brokering companies who resell the coal to the ultimate users. We are subject to being adversely affected by any decline in the financial condition and creditworthiness of these energy trading and brokering companies. In addition, as one of the largest suppliers of metallurgical coal to the United States steel industry and a significant exporter to foreign users, we are subject to being adversely affected by any decline in the financial condition or production volume of both United States and foreign steel producers.

Some of our customers may be unwilling to take all of their contracted tonnage or may request a price lower than their contracted price.

Many of our customers experienced lower demand for their products and services due to the recent economic downturn and have been switching of electricity generation from coal burning plants to natural gas plants. The lower demand for our customers' products resulted and may continue to result in lower demand for the coal used in their business. Some of our customers have requested and others may request deferrals of shipments, reduction of contracted sales tonnages and/or reduction of the contracted sales price. If we believe it is in our best interests to agree to any reduction in contracted price and/or tons from our customers, there could be an adverse effect on our cash flows, results of operations or financial condition.

We must obtain governmental permits and approvals for mining operations, which can be a costly and time-consuming process, can result in restrictions on our operations, and is subject to litigation that may delay or prevent us from obtaining necessary permits.

Our operations are principally regulated under surface mining permits issued pursuant to the Surface Mining Control and Reclamation Act and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. Separately, the Clean Water Act requires permits for operations that discharge into waters of the United States. Valley fills and refuse impoundments are authorized under permits issued by the U.S. Army Corps of Engineers (the "Corps"). The Environmental Protection Agency (the "EPA") has the authority, which it has rarely exercised until recently, to object to permits issued by the Corps. While the Corps is authorized to issue permits even when the EPA has objections, the EPA does have the ability to override the Corps decision and "veto" the permits. In September 2009, the EPA announced it had identified 79 pending permit applications for Appalachian surface coal mining, under a coordination process with the Corps and the United States Department of the Interior entered into in June 2009, that EPA believes warrant further review because of its continuing concerns about water quality and/or regulatory compliance issues. These include five of our permit applications. While the EPA has stated that its identification of these 79 permits does not constitute a determination that the mining involved cannot be permitted under the Clean Water Act and does not constitute a final recommendation from the EPA to the Corps on these projects, it is unclear how long the further review will take for our five permits or what the final outcome will be. It is also unclear what impact this process may have on our future applications for surface coal mining permits. Permitting under the Clean Water Act has been a frequent subject of litigation by environmental advocacy groups that has resulted in periodic delays in such permits issued by the Corps. Additionally, certain operations (particularly preparation plants) have permits issued pursuant to the Clean Air Act and state counterpart laws allowing and controlling the discharge of air pollutants. Regulatory authorities exercise considerable discretion in the timing of permit issuance. Requirements imposed by these authorities may be costly and time-consuming and may result in delays in, or in some instances preclude, the commencement or continuation of development or production operations. Adverse outcomes in lawsuits challenging permits or failure to comply with applicable regulations could result in the suspension, denial or revocation of required permits, which could have a material adverse impact on our cash flows, results of operations or financial condition. See also Note 18, "Contingencies – Surface Mining Fills" to the Notes to Consolidated Financial Statements.

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate change, are resulting in increased regulation of coal combustion in many jurisdictions, and interest in further regulation, which could significantly affect demand for our products.

The Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. Such regulation may require significant emissions control expenditures for many coal-fired power plants. As a result, the generators may switch to other fuels that generate less of these emissions or install more effective pollution control equipment, possibly reducing future demand for coal and the construction of coal-fired power plants. The majority of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser's plant or results in specified increases in the cost of coal or its use.

Global climate change continues to attract considerable public and scientific attention. Widely publicized scientific reports, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate Change released in 2007, have also engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. A considerable and increasing amount of attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants. According to the EIA report, "Emissions of Greenhouse Gases in the United States 2007," coal combustion accounts for 30% of man-made greenhouse gas emissions in the United States. In April 2009, the EPA released a proposed rule making an "endangerment finding" with respect to six greenhouse gases, including carbon dioxide, due to effects on public health and welfare; if finalized, such a finding would trigger the process under the Clean Air Act for developing air quality standards for these greenhouse gases and establishing emission standards for sources. In June of 2009, the U.S. House of Representatives passed the so-called "Waxman-Markey" bill, which provides for substantial reductions in greenhouse gases, including carbon dioxide, through a "cap and trade" system. "Cap and Trade" legislation was also introduced in the U.S. Senate in the fall of 2009. Further developments in connection with legislation, regulations or other limits on greenhouse gas emissions and other environmental impacts from coal combustion, both in the United States and in other countries where we sell coal, could have a material adverse effect on our cash flows, results of operations or financial condition.

Critical Accounting Estimates and Assumptions

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts. These estimates and assumptions are based on information available as of the date of the financial statements. Significant changes to the estimates and assumptions used in determining certain liabilities described below could introduce substantial volatility to our costs. The following critical accounting estimates and assumptions were used in the preparation of the financial statements:

Defined Benefit Pension Plans

The estimated cost and benefits of non-contributory defined benefit pension plans are determined by independent actuaries, who, with management's review and approval, use various actuarial assumptions, including discount rate, future rate of increase in compensation levels and expected long-term rate of return on pension plan assets. The discount rate is an estimate of the current interest rate at which the applicable liabilities could be effectively settled as of the measurement date. In estimating the discount rate, forecasted cash flows were discounted using each year's associated spot interest rate on high quality fixed income investments. At December 31, 2009 and 2008, the discount rate used to determine defined benefit pension liability was 6.00% and 6.10%, respectively. The impact of lowering the discount rate 0.25% for 2009 would have increased the 2009 net periodic pension expense by approximately $2.0 million. The rate of increase in compensation levels is determined based upon our long-term plans for such increases. The rate of increase in compensation levels used was 3.0% and 4.0% for the years ended December 31, 2009 and 2008, respectively. The expected long-term rate of return on pension plan assets is based on long-term historical return information and future estimates of long-term investment returns for the target asset allocation of investments that comprise plan assets. During 2009, we made a temporary shift in our pension investments' targeted asset allocation in response to the volatility and uncertainty in the financial markets. We invested a large percentage of plan assets in debt securities with a fixed duration with the intent to return to the long-term targeted asset allocation upon maturity of the fixed duration investments. As we plan to return to our targeted asset allocation, we believe the expected long-term rate of return on plan assets of 8.0% continues to be appropriate. The expected long-term rate of return on plan assets used to determine expense in each period was 8.0% for both of the years ended December 31, 2009 and 2008. A 0.5% decrease in the expected long-term rate of return assumption would have increased the 2009 net periodic pension expense by approximately $1.0 million. The actuarial assumptions we use may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. While we believe that the assumptions used are appropriate, differences in actual experience or changes in assumptions might materially affect our financial position or results of operations. See Note 5 to the Notes to Consolidated Financial Statements for further discussion on our pension plans.

Coal Workers' Pneumoconiosis

We are responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, and various states' statutes, for the payment of medical and disability benefits to eligible recipients resulting from occurrences of coal workers' pneumoconiosis disease (black lung). An annual evaluation is prepared by independent actuaries, who, after review and approval by management, use various assumptions regarding disability incidence, medical costs trend, cost of living trend, mortality, death benefits, dependents and interest rates. We record expense related to this obligation using the service cost method. At December 31, 2009 and 2008, the discount rate used to determine the black lung liability was 6.00% and 6.10%, respectively. Included in Note 11 to the Notes to Consolidated Financial Statements is a medical cost trend and cost of living trend sensitivity analysis.

Workers' Compensation

Our operations have workers' compensation coverage through a combination of either self-insurance, participation in a state run program, or commercial insurance. We accrue for the self-insured liability by recognizing cost when it is probable that the liability has been incurred and the cost can be reasonably estimated. To assist in the determination of this estimated liability we utilize the services of third-party administrators who derive claim reserves from historical experience. These third parties provide information to independent actuaries, who after review and consultation with management with regards to actuarial assumptions, including discount rate, prepare an evaluation of the self-insured liabilities. At December 31, 2009 and 2008, the discount rate used to determine the self-insured workers' compensation liability obligation was 4.75% and 5.00%, respectively. A decrease in the assumed discount rate increases the workers' compensation self-insured liability and related expense. Actual experience in settling these liabilities could differ from these estimates, which could increase our costs. See Note 11 to the Notes to Consolidated Financial Statements for further discussion on workers' compensation.

Other Postretirement Benefits

Our sponsored health care plans provide retiree health benefits to eligible union and non-union retirees who have met certain age and service requirements. Depending on year of retirement, benefits may be subject to annual deductibles, coinsurance requirements, lifetime limits, and retiree contributions. These plans are not funded. We pay costs as incurred by participants. The estimated cost and benefits of the retiree health care plans are determined by independent actuaries, who, after review and approval by management, use various actuarial assumptions, including discount rate, expected trend in health care costs and per capita claims costs. At December 31, 2009 and 2008, the discount rate used to determine the other postretirement benefit liability was 6.00% and 6.10%, respectively. The impact of lowering the discount rate 0.25% for 2009 would have increased the 2009 net periodic postretirement benefit cost by approximately $0.4 million. At December 31, 2009, assumptions of our health care plans' cost trend were projected at annual rates of 8.3% for pre-Medicare claims, 8.6% for Medicare-eligible claims and 7.0% for Medicare supplemental plans, all ranging down to 4.5% by 2029 and remaining level thereafter. The impact of increasing the health care cost trend rate by 1.0% would have increased the 2009 net periodic postretirement benefit cost by approximately $1.8 million. Included in Note 10 to the Notes to Consolidated Financial Statements is a sensitivity analysis on the health care trend rate assumption.

Reclamation and Mine Closure Obligations

The SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Total reclamation and mine-closing liabilities are based upon permit requirements and engineering estimates related to these requirements. GAAP requires that asset retirement obligations be recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows. Management and engineers periodically review the estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed. In estimating future cash flows, we considered the estimated current cost of reclamation and applied inflation rates and a third-party profit, as necessary. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The discount rate applied is based on the rates of treasury bonds with maturities similar to the estimated future cash flow, adjusted for our credit standing. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

Contingencies

We are parties to a number of legal proceedings, incident to our normal business activities. These matters include contract disputes, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates, we do not believe that the estimated liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition. However, it is reasonably possible that the ultimate liabilities in the future with respect to these lawsuits and claims may be material to our cash flows, results of operations or financial condition. See Item 3. Legal Proceedings and Note 18 to the Notes to Consolidated Financial Statements for further discussion on our contingencies.

Income Taxes

GAAP requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. GAAP also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including tax attribute carrybacks, the future reversals of existing taxable temporary differences, the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in the evaluation of our valuation allowance, we record a change in valuation allowance through income tax expense in the period such determination is made.

We are required to establish reserves based upon management's assessment of exposure associated with tax positions taken relative to temporary and permanent tax differences and tax credits, plus penalties and interest, if any, on the accrued uncertain tax positions. The tax reserves are analyzed periodically and adjustments are made as events occur to warrant adjustment to the reserves. Management believes that we have adequately provided for any income taxes that may ultimately be paid with respect to all open tax years.

Coal Reserve Values

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves. Many of these uncertainties are 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 internal engineers, geologists and financial associates. Some of the factors and assumptions that impact economically recoverable reserve estimates include: (i) geological conditions; (ii) historical production from similar areas with similar conditions; (iii) the assumed effects of regulations and taxes by governmental agencies; (iv) assumptions governing future prices; and (v) future operating costs.

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal 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, revenue and expenditures with respect to reserves will likely vary from estimates, and these variances may be material. Variances would affect both the Consolidated Statements of Income, in the form of revenue and expenditures, as well as the Consolidated Balance Sheets, in the form of valuation of coal reserves, depletion rates and potential impairment.

Derivative Instruments

Upon entering into each coal sales and coal purchase contract, we evaluate each of our contracts to determine if they qualify for the NPNS exception prescribed by current accounting guidance. The majority of our contracts qualify for the NPNS exception and therefore are not reflected in the Consolidated Balance Sheets and Consolidated Statements of Income. For those contracts that do not qualify for the NPNS exception at inception or at some point during the duration of the contract, the contracts are required to be accounted for as derivative instruments and must be recognized as assets or liabilities and measured at fair value. To establish fair values for these contracts, we use bid/ask price quotations obtained from independent third-party brokers. We also consider the risk of nonperformance of or nonpayment by the counterparties when determining the fair values for these contracts by evaluating the credit quality and financial condition of each counterparty. If the number of third-party brokers should decrease or market liquidity is reduced, we could experience difficulty in determining the fair value of our derivative instruments. The net change in the fair value of our contracts that did not qualify for the NPNS exception at December 31, 2009 and 2008, was recognized as an unrealized (gain) loss in the Consolidated Statements of Income under the caption (Gain) loss on derivative instruments.

In evaluating our contracts for the NPNS exception at inception, we consider many factors, including management's intent and ability to physically deliver or take physical delivery of the coal, as well as the counterparty's intent and ability to physically accept or deliver coal. These factors may change over the duration of a contract, due to, for example, the counterparty's inability to physically accept or deliver coal or to our decision to net settle a portion or all of a forward contract by entering into an offsetting contract. These facts and circumstances may cause a contract to no longer qualify for the NPNS exception. If a contract originally evaluated as qualifying for the NPNS exception no longer qualifies, it is prospectively accounted for as a derivative instrument and recognized as an asset or liability and measured at fair value. To the extent there is an increase in the number of contracts that do not qualify for the NPNS exception, it could have a significant impact on our results of operations or financial condition. See Note 15 to the Notes to Consolidated Financial Statements for further discussion of our derivative instruments.

Recent Accounting Pronouncements

Refer to Note 1 in the Notes to Consolidated Financial Statements for information concerning the effect of recent accounting pronouncements.

Item 7A. Quantitative and Qualitative Discussions about Market Risk

Our net interest expense is currently not sensitive to changes in the general level of short-term interest rates. At December 31, 2009, all of the outstanding $1,319.1 million of our debt was under fixed-rate instruments. However, if it should become necessary to borrow under our ABL Facility, those borrowings would be made at a variable rate. Interest income is sensitive to changes in short-term interest rates.

In 2009, we primarily managed market price risk for coal through the use of long-term coal supply agreements, which are contracts with a term of one year or more in duration, rather than through the use of derivative instruments. We estimate that the percentage of tons sold pursuant to these long-term contracts was 99% for our fiscal year ended December 31, 2009. We anticipate that in 2010, the percentage of our tons sold pursuant to long-term contracts will be comparable with the percentage of our sales for 2009. The prices for coal shipped under long-term contracts may be below the current market price for similar types of coal at any given time. As a consequence of the substantial volume of our sales that are subject to these long-term agreements, we have less coal available with which to capitalize on stronger coal prices if and when they arise. In addition, because long-term contracts may allow the customer to elect volume flexibility based on requirements, our ability to realize the higher prices that may be available in the spot market may be restricted when customers elect to purchase higher volumes under such contracts, or our exposure to market-based pricing may be increased should customers elect to purchase fewer tons.

From time to time we may also purchase coal directly from third parties to supplement our produced and processed coal in order to provide coal to meet customer requirements under sales contracts. Certain of our purchase and sale contracts do not qualify for the NPNS exception and are accordingly measured at fair value in current period earnings. The use of purchase and sales contracts which do not qualify for the NPNS exception could materially affect our results of operations as a result of the requirement to mark them to market at the end of each reporting period.

These transactions give rise to commodity price risk, which represents the potential gain or loss that can be caused by an adverse change in the price of coal. Outstanding purchase and sales contracts at December 31, 2009, that do not qualify for the NPNS exception are summarized as follows:

	Price Range	Tons Outstanding	Delivery Period
Purchase Contracts	$51.00 - $60.25	980,000	01/01/10 - 12/31/10
Sales Contracts	$56.35 - $127.00	1,120,000	01/01/10 - 12/31/11

As of December 31, 2009, a hypothetical increase of 10% in the forward market price would result in an additional fair value loss recorded for these derivative instruments of $1.0 million. A hypothetical decrease of 10% in the forward market price would result in a reduction in the fair value loss recorded for these derivative instruments of $1.0 million.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Massey Energy Company

We have audited the accompanying consolidated balance sheets of Massey Energy Company as of December 31, 2009 and 2008, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedule listed in Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Massey Energy Company at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 6 to the consolidated financial statements, in 2009 the Company changed its method for accounting for convertible debt instruments with the adoption of the guidance originally issued in the accounting provisions of Financial Accounting Standards Board (FASB) Staff Position ABP 14-1, Accounting for Convertible Debt Instruments That May be Settled in Cash upon Conversion (codified in FASB ASC Topic 470, Debt) effective January 1, 2009. Also, as discussed in Note 7 to the consolidated financial statements, in 2007 the Company changed its method for accounting for income taxes to comply with the guidance originally issued in FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (codified in FASB ASC Topic 740, Income Taxes).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Massey Energy Company's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2010 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

Richmond, Virginia
March 1, 2010

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(In Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2009	2008	2007
		As Adjusted	
Revenues			
Produced coal revenue	$ 2,318,489	$ 2,559,929	$ 2,054,413
Freight and handling revenue	218,203	306,397	167,641
Purchased coal revenue	62,721	30,684	108,191
Other revenue	91,746	92,779	83,278
Total revenues	2,691,159	2,989,789	2,413,523
Costs and expenses			
Cost of produced coal revenue	1,850,058	1,910,953	1,641,774
Freight and handling costs	218,203	306,397	167,641
Cost of purchased coal revenue	57,108	28,517	95,241
Depreciation, depletion and amortization, applicable to:			
Cost of produced coal revenue	268,317	253,737	242,755
Selling, general and administrative	1,860	3,590	3,280
Selling, general and administrative	97,381	77,015	75,845
Other expense	8,705	3,207	7,308
Litigation charge	-	250,061	-
Loss on financing transactions	189	5,006	-
(Gain) loss on derivative instruments	(37,638)	22,552	-
Total costs and expenses	2,464,183	2,861,035	2,233,844
Income before interest and taxes	226,976	128,754	179,679
Interest income	12,583	23,576	23,969
Interest expense	(102,294)	(96,866)	(74,145)
Loss on short-term investment	-	(6,537)	-
Income before taxes	137,265	48,927	129,503
Income tax expense	(32,832)	(1,098)	(35,405)
Net income	$ 104,433	$ 47,829	$ 94,098
Net income per share			
Basic	$ 1.23	$ 0.58	$ 1.17
Diluted	$ 1.22	$ 0.58	$ 1.17
Shares used to calculate income per share			
Basic	84,992	81,816	80,123
Diluted	85,598	82,895	80,654

See Notes to Consolidated Financial Statements

MASSEY ENERGY COMPANY
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Amounts)

	December 31, 2009	December 31, 2008 As Adjusted
ASSETS		
Current Assets		
Cash and cash equivalents	$ 665,762	$ 606,997
Short-term investment	10,864	39,383
Trade and other accounts receivable, less allowance of $1,303 and $873, respectively	121,577	233,266
Inventories	269,826	233,168
Income taxes receivable	10,546	6,621
Other current assets	235,990	116,061
Total current assets	1,314,565	1,235,496
Property, plant and equipment, net	2,344,770	2,297,696
Other noncurrent assets	140,336	139,186
Total assets	$ 3,799,671	$ 3,672,378
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable, principally trade and bank overdrafts	$ 164,979	$ 244,201
Short-term debt	23,531	1,976
Payroll and employee benefits	63,590	56,959
Other current liabilities	192,835	201,017
Total current liabilities	444,935	504,153
Noncurrent Liabilities		
Long-term debt	1,295,555	1,310,181
Deferred income taxes	209,230	177,294
Pension obligation	55,610	63,304
Other noncurrent liabilities	538,058	490,834
Total noncurrent liabilities	2,098,453	2,041,613
Total liabilities	2,543,388	2,545,766
Shareholders' Equity		
Capital stock		
Preferred – authorized 20,000,000 shares without par value; none issued	-	-
Common – authorized 150,000,000 shares of $0.625 par value; issued 86,213,582 and 85,447,970 shares, respectively	53,868	53,378
Additional capital	568,995	542,519
Retained earnings	716,089	632,077
Accumulated other comprehensive loss	(82,669)	(101,362)
Total shareholders' equity	1,256,283	1,126,612
Total liabilities and shareholders' equity	$ 3,799,671	$ 3,672,378

See Notes to Consolidated Financial Statements.

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended December 31,		
	2009	2008 As Adjusted	2007
Cash Flows from Operating Activities			
Net income	$ 104,433	$ 47,829	$ 94,098
Adjustments to reconcile Net income to Cash provided by operating activities:			
Depreciation, depletion and amortization	270,177	257,327	246,035
Bond discount amortization	19,054	8,028	-
Share-based compensation expense	12,747	13,856	17,095
Deferred income taxes	18,407	5,573	27,403
Gain on disposal of assets	(15,984)	(2,926)	(6,751)
Gain on reserve exchanges	(26,537)	(32,449)	(10,284)
Reserve on note receivable	6,000	-	-
Loss on financing transactions	369	11,431	-
Net unrealized (gains) losses in derivative instruments	(53,116)	22,552	-
Unrealized loss on short-term investment	-	6,537	-
Accretion of asset retirement obligations	13,991	11,844	11,758
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable	100,020	(77,953)	19,253
(Increase) decrease in inventories	(36,658)	(49,808)	7,696
(Increase) decrease in income taxes receivable	(2,350)	10,048	(35,714)
(Increase) decrease in other current assets	(67,075)	49,079	6,382
Increase in other assets	(1,589)	(9,621)	(5,362)
(Decrease) increase in accounts payable	(79,222)	95,995	31,049
Increase (decrease) in other accrued liabilities	9,882	21,189	(558)
Increase in pension obligation	10,796	1,625	5,171
Increase (decrease) in other noncurrent liabilities	10,916	(118)	(212)
Asset retirement obligation payments	(5,352)	(4,957)	(11,061)
Cash provided by operating activities	288,909	385,081	395,998
Cash Flows from Investing Activities			
Capital expenditures	(274,552)	(736,529)	(270,461)
Redesignation of cash equivalent to short-term investment	-	(217,900)	-
Proceeds from redemption of short-term investment	28,519	171,980	-
Proceeds from sale of assets	19,010	5,958	28,118
Proceeds from insurance recovery	15,395	-	-
Cash utilized by investing activities	(211,628)	(776,491)	(242,343)
Cash Flows from Financing Activities			
Issuance of common stock	-	258,188	-
Stock repurchase	-	-	(29,991)
Repayments of capital lease obligations	(2,584)	(1,911)	(2,409)
Proceeds from issuance of 3.25% convertible senior notes	-	674,136	-
Repurchase of 3.25% convertible senior notes	(9,982)	(10,450)	-
Tender payment for 6.625% senior notes	-	(322,139)	-
Redemption of 4.75% convertible senior notes	(70)	-	-
Proceeds from sale-leaseback transactions	-	41,318	13,146
Cash dividends paid	(20,421)	(21,310)	(12,837)
Proceeds from stock options exercised	11,306	16,519	4,001
Excess income tax benefit (expense) from stock option exercises	3,235	(1,164)	410
Cash (utilized) provided by financing activities	(18,516)	633,187	(27,680)
Increase in cash and cash equivalents	58,765	241,777	125,975
Cash and cash equivalents at beginning of period	606,997	365,220	239,245
Cash and cash equivalents at end of period	$ 665,762	$ 606,997	$ 365,220
Supplemental Cash Flow Information			
Cash paid during the period for income taxes	$ 13,539	$ 4,219	$ 34,502

See Notes to Consolidated Financial Statements.

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(In Thousands, Except Per Share Amounts)

	Common Stock Shares	Common Stock Amount	Additional Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock	Total Shareholders' Equity
Balance at December 31, 2006	81,066	$ 51,458	$ 220,650	$ 515,894	$ (40,716)	$ (49,995)	$ 697,291
Net income				94,098			94,098
Other comprehensive income:							
Pension and postretirement plans, net of deferred tax of $8,754					13,692		13,692
Comprehensive income							107,790
Adoption of accounting standards:							
Uncertainty in income taxes				5,182			5,182
Dividends declared ($0.17 per share)				(13,587)			(13,587)
Stock option expense			8,308				8,308
Exercise of stock options	299	188	3,813				4,001
Stock option tax benefit			410				410
Restricted stock	155	97	4,503				4,600
Share repurchase	(1,576)					(29,991)	(29,991)
Balance at December 31, 2007	79,944	$ 51,743	$ 237,684	$ 601,587	$ (27,024)	$ (79,986)	$ 784,004
Net income				47,829			47,829
Other comprehensive income:							
Pension and postretirement plans, net of deferred tax of $47,528					(74,338)		(74,338)
Comprehensive loss							(26,509)
Adoption of accounting standards:							
Equity component of 3.25% convertible senior notes			98,397				98,397
Dividends declared ($0.21 per share)				(17,339)			(17,339)
Stock option expense			8,204				8,204
Exercise of stock options	787	492	16,027				16,519
Stock option tax expense			(1,164)				(1,164)
Restricted stock	300	185	5,467				5,652
Issuance of stock for debt conversion	34	21	639				660
Issuance of additional common shares	4,370	937	177,265			79,986	258,188
Balance at December 31, 2008 (As Adjusted)	85,435	$ 53,378	$ 542,519	$ 632,077	$ (101,362)	$ -	$ 1,126,612
Net income				104,433			104,433
Other comprehensive income:							
Pension and postretirement plans, net of deferred tax of $9,105					18,693		18,693
Comprehensive income							123,126
Dividends declared ($0.24 per share)				(20,421)			(20,421)
Stock option expense			6,197				6,197
Exercise of stock options	515	321	10,985				11,306
Stock option tax benefit			3,235				3,235
Restricted stock	262	169	6,381				6,550
Equity component of 3.25% convertible senior notes			(322)				(322)
Balance at December 31, 2009	86,212	$ 53,868	$ 568,995	$ 716,089	$ (82,669)	$ -	$ 1,256,283

See Notes to Consolidated Financial Statements.

1. Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements include the accounts of Massey Energy Company ("we", "our", or "us"), its wholly owned and sole, direct operating subsidiary A.T. Massey Coal Company, Inc. ("A.T. Massey") and A.T. Massey's wholly owned direct and indirect subsidiaries. Inter-company transactions and accounts are eliminated in consolidation. We have no independent assets or operations. We do not have a controlling interest in any separate independent operations. Investments in business entities in which we do not have control, but have the ability to exercise significant influence over the operating and financial policies, are accounted for under the equity method.

A.T. Massey and substantially all of our indirect operating subsidiaries, each such subsidiary being indirectly 100% owned by us, fully and unconditionally, jointly and severally, guarantees our obligations under the 6.625% senior notes due 2010 ("6.625% Notes"), the 6.875% senior notes due 2013 ("6.875% Notes"), the 3.25% convertible senior notes due 2015 ("3.25% Notes") and the 2.25% convertible senior notes due 2024 ("2.25% Notes"). The subsidiaries not providing a guarantee of the 6.625% Notes, the 6.875% Notes, the 3.25% Notes and the 2.25% Notes are minor (as defined under Securities and Exchange Commission ("SEC") Rule 3-10(h)(6) of Regulation S-X). See Note 6 for a more complete discussion of debt.

In May 2009, the Financial Accounting Standards Board ("FASB") issued accounting guidance, effective for financial statements issued for interim and annual periods ending after June 15, 2009, which requires us to disclose the date through which we have evaluated subsequent events and whether the date corresponds with the release of our financial statements. We have evaluated subsequent events through the date the financial statements were issued.

Codification

In June 2009, the FASB issued new accounting guidance, effective for financial statements issued for interim and annual periods ending after September 15, 2009, which identifies the FASB Accounting Standards Codification ("Codification") as the authoritative source of GAAP in the United States. Rules and interpretive releases of the SEC under federal securities laws are also sources of authoritative GAAP for SEC registrants. Codification is not intended to change GAAP. The adoption of this new accounting guidance had no impact on our financial position or results of operations.

Use of Estimates

The preparation of the financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect reported amounts. These estimates are based on information available as of the date of the financial statements. Therefore, actual results could differ from those estimates. The most significant estimates used in the preparation of the consolidated financial statements are related to defined benefit pension plans, coal workers' pneumoconiosis ("black lung"), workers' compensation, other postretirement benefits, reclamation and mine closure obligations, contingencies, income taxes, coal reserve estimates, stock options and derivative instruments.

Fair Value Measurements

We adopted new accounting guidance on January 1, 2008 and 2009, for financial and non-financial assets and liabilities, respectively, that requires their categorization based upon three levels of judgment associated with the inputs used to measure their fair value. Neither adoption had a material impact on our financial position or results of operations. See Note 16 to the Notes to Consolidated Financial Statements for more information.

Revenue Recognition

Produced coal revenue is realized and earned when title passes to the customer. Coal sales are made to our customers under the terms of coal supply agreements, most of which are long-term (one year or greater). Under the typical terms of these coal supply agreements, title and risk of loss transfer to the customer at the mine, dock, or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s) that serves each of our mines. We incur certain "add-on" taxes and fees on coal sales. Coal sales reported in Produced coal revenues include these "add-on" taxes and fees charged by various federal and state governmental bodies.

Freight and handling revenue consists of shipping and handling costs invoiced to coal customers and paid to third-party carriers. These revenues are directly offset by Freight and handling costs.

Purchased coal revenue represents revenue recognized from the sale of coal purchased from third-party production sources. We take title to the purchased coal, which we then resell to our customers. Typically, title and risk of loss transfer to the customer at the mine, dock or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s).

Other revenue includes refunds on railroad agreements, royalties related to coal lease agreements, gas well revenue, gains on the sale of non-strategic assets and reserve exchanges, joint venture revenue and other miscellaneous revenue. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced. Certain agreements require minimum lease payments regardless of the extent to which minerals are produced from the leasehold. The terms of these agreements generally range from specified periods of 5 to 10 years, or can be for an unspecified period until all reserves are depleted.

Derivative Instruments

Effective January 1, 2009, we adopted new accounting guidance related to disclosures about derivative instruments, which was issued to require disclosures providing an enhanced understanding of how and why derivative instruments are used, how they are accounted for and their effect on an entity's financial condition, performance and cash flows. See Note 15 to the Notes to Consolidated Financial Statements for more information. Our coal sales and coal purchase contracts that do not qualify for the normal purchase normal sale ("NPNS") exception as prescribed by current accounting guidance are offset on a counterparty-by-counterparty basis for derivative instruments executed with the same counterparty under a master netting arrangement.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents are primarily invested in money market funds, which consist of highly liquid investments with maturities of 90 days or less at the date of purchase.

Short-Term Investment

Short-term investment is comprised of an investment in The Reserve Primary Fund ("Primary Fund"), a money market fund that suspended redemptions in September 2008 and is being liquidated. Upon suspension of redemptions, we determined that our investment in the Primary Fund did not meet the definition of a security, within the scope of current accounting guidance, since the equity investment no longer had a readily determinable fair value. Therefore, the investment has been classified as a short-term investment, subject to the cost method of accounting, on our Consolidated Balance Sheets.

Trade Receivables

Trade accounts receivable are recorded at the invoiced amount and are non-interest bearing. We maintain a bad debt reserve based upon the expected collectibility of our accounts receivable. The reserve includes specific amounts for accounts that are likely to be uncollectible, as determined by such variables as customer creditworthiness, the age of the receivables, bankruptcies and disputed amounts. Account balances are charged off against the reserve after all means of collection have been exhausted and the potential for recovery is considered remote.

Inventories

Produced coal and supplies inventories generally are stated at the lower of average cost or net realizable value. Coal inventory costs include labor, supplies, equipment, operating overhead and other related costs. Purchased coal inventories are stated at the lower of cost, computed on the first-in, first-out method, or net realizable value.

Surface mine stripping costs

We account for the costs of removing overburden and waste materials (stripping costs) at surface mines differently, depending upon whether the costs are incurred prior to producing coal (pre-production) versus after a more than de minimis amount of shippable product is produced (post-production). Production-related stripping costs are only included as a component of inventory if they are associated with extracted or saleable inventories. Pre-production stripping costs are capitalized in mine development and amortized over the life of the developed pit consistent with coal industry practices. Post-production stripping costs are expensed as incurred and recorded as Cost of produced coal revenue.

Pre-production stripping costs – At existing surface operations, additional pits may be added to increase production capacity in order to meet customer requirements. These expansions may require significant capital to purchase additional equipment, expand the workforce, build or improve existing haul roads and create the initial pre-production box cut to remove overburden (i.e. advance stripping costs) for new pits at existing operations. If these pits operate in a separate and distinct area of the mine, the costs associated with initially uncovering coal (i.e. advance stripping costs incurred for the initial box cuts) for production are capitalized in mine development and amortized over the life of the developed pit consistent with coal industry practices.

Post-production stripping costs – Where new pits are routinely developed as part of a contiguous mining sequence, we expense such costs as incurred. The development of a contiguous pit typically reflects the planned progression of an existing pit, thus maintaining production levels from the same mining area utilizing the same employee group and equipment.

Income Taxes

We account for income taxes under the liability method, which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. It also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including carrybacks, the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in the evaluation of our valuation allowance, we record a change in valuation allowance through income tax expense in the period such determination is made.

A tax position is initially recognized in the financial statements when it is more likely than not the position will be sustained upon examination by applicable taxing authorities. Such tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not to be realized upon ultimate settlement with the taxing authority assuming full knowledge of the position and all relevant facts. We accrue interest and penalties, if any, related to unrecognized tax benefits in Other noncurrent liabilities and recognize the related expense in Income tax expense.

Property, Plant and Equipment

Property, plant and equipment are carried at cost and stated net of accumulated depreciation. Expenditures that extend the useful lives of existing buildings and equipment are capitalized. Maintenance and repairs are expensed as incurred. Coal exploration costs are expensed as incurred. Costs incurred to maintain current production capacity at a mine and exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Development costs, including pre-production stripping costs, applicable to the opening of new coal mines and certain mine expansion projects are capitalized until production begins. When properties are retired or otherwise disposed, the related cost and accumulated depreciation are removed from the respective accounts and any profit or loss on disposition is credited or charged to Other revenue.

Our coal reserves are controlled either through direct ownership or through leasing arrangements. Mining properties owned in fee represent owned coal properties carried at cost. Leased mineral rights represent leased coal properties carried at the cost of acquiring those leases. The leases are generally long-term in nature (original term five to fifty years or until the mineable and merchantable coal reserves are exhausted), and substantially all of the leases contain provisions that allow for automatic extension of the lease term as long as mining continues.

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

	Years
Buildings and plants	20 to 30
Equipment	3 to 20
Capital leases	4 to 7

Ownership of assets under capital leases transfers to us at the end of the lease term. Depreciation of assets under capital leases is included within Depreciation, depletion and amortization.

Amortization of development costs is computed using the units-of-production method over the estimated proven and probable reserve tons.

Depletion of mining properties owned in fee and leased mineral rights is computed using the units-of-production method over the estimated proven and probable reserve tons (as adjusted for recoverability factors). As of December 31, 2009, approximately $168.9 million of costs associated with mining properties owned in fee and leased mineral rights are not currently subject to depletion as mining has not begun or production has been temporarily idled on the associated coal reserves.

We capitalize certain costs incurred in the development of internal-use software, including external direct material and service costs. All costs capitalized are amortized using the straight-line method over the estimated useful life not to exceed 7 years.

Impairment of Long-Lived Assets

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the assets is then reduced to their estimated fair value, which is usually measured based on an estimate of future discounted cash flows. There were no material impairment losses recorded during the periods covered by the consolidated financial statements.

Advance Mining Royalties

Coal leases that require minimum annual or advance payments and are recoverable from future production are generally deferred and charged to expense as the coal is subsequently produced. At December 31, 2009 and 2008, advance mining royalties included in Other noncurrent assets totaled $40.4 million and $35.3 million, net of an allowance of $12.8 million and $14.7 million, respectively.

Reclamation

We record asset retirement obligations ("ARO") as a liability based on fair value, which is calculated as the present value of the estimated future cash flows, in the period in which it is incurred. Management and engineers periodically review the estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed. In estimating future cash flows, we consider the estimated current cost of reclamation and apply inflation rates and a third-party profit, as necessary. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. When the liability is initially recorded, the offset is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Accretion expense is included in Cost of produced coal revenue. To settle the liability, the obligation is paid, and to the extent there is a difference between the liability and the amount of cash paid, a gain or loss upon settlement is incurred. Additionally, we perform a certain amount of required reclamation of disturbed acreage as an integral part of our normal mining process; these costs are expensed as incurred. See Note 9 for a more complete discussion of our reclamation liability.

Pension Plans

We sponsor a noncontributory defined benefit pension plan covering substantially all administrative and non-union employees. Our policy is to annually fund the defined benefit pension plan at or above the minimum amount required by law. We also sponsor a nonqualified supplemental benefit pension plan for certain salaried employees, which is unfunded.

Costs of benefits to be provided under our defined benefit pension plans are accrued over the employees' estimated remaining service life. These costs are determined on an actuarial basis. We recognize the funded status of our benefit plans in our Consolidated Balance Sheet and recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. These amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost. See Note 5 for a more complete discussion of our pension plans.

Black Lung Benefits

We are responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, and under various states' statutes for the payment of medical and disability benefits to employees and their dependents resulting from occurrences of black lung. We provide for federal and state black lung claims principally through a self-insurance program.

Costs of benefits to be provided under our accumulated black lung obligations are accrued over the employees' estimated remaining service life. These costs are determined on an actuarial basis. We recognize the funded status of our black lung obligations in our Consolidated Balance Sheet and recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. We use the service cost method to account for our self-insured black lung obligation. The liability measured under the service cost method represents the discounted future estimated cost for former employees either receiving or projected to receive benefits, and the portion of the projected liability relative to prior service for active employees projected to receive benefits. Expense for black lung under the service cost method represents the service cost, which is the portion of the present value of benefits allocated to the current year, interest on the accumulated benefit obligation, and amortization of unrecognized actuarial gains and losses. We amortize unrecognized actuarial gains and losses over a five-year period. See Note 11 for a more complete discussion of black lung benefits.

Workers' Compensation

We are liable for workers' compensation benefits for traumatic injuries under state workers' compensation laws in states in which we have operations. Our operations have workers' compensation coverage through a combination of either a self-insurance program, or commercial insurance through a deductible or first dollar insurance policy. We record our self-insured liability on a discounted actuarial basis using various assumptions, including discount rate and future cost trends. See Note 11 for a more complete discussion of workers' compensation benefits.

Postretirement Benefits Other than Pensions

We sponsor defined benefit health care plans that provide postretirement medical benefits to eligible union and non-union members. Costs of benefits to be provided under our postretirement benefits other than pensions are accrued over the employees' estimated remaining service life. These costs are determined on an actuarial basis. We recognize the funded status of our benefit plans in our Consolidated Balance Sheet and recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. These amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost.

Under the Coal Industry Retiree Health Benefits Act of 1992 (the "Coal Act"), coal producers are required to fund medical and death benefits of certain retired union coal workers based on premiums assessed by the United Mine Workers of America ("UMWA") Benefit Funds. We treat our obligation under the Coal Act as participation in a multi-employer plan as permitted by GAAP and record the cost of our obligation as expense as payments are assessed. See Note 10 for a more complete discussion of postretirement benefits other than pensions.

Stock-based Compensation

We measure the compensation cost of equity instruments based on their grant-date fair value, which is recognized as expense on a straight-line basis over the corresponding vesting period. We use the Black-Scholes option-pricing model to determine the fair value of stock options as of the date of grant and certain liability awards with option characteristics (i.e., stock appreciation rights, or "SARs"). See Note 12 for a more complete discussion of stock-based compensation.

Convertible Debt Securities

On January 1, 2009, new accounting guidance became effective relating to our 3.25% Notes. The guidance applies to all convertible debt instruments that have a ''net settlement feature,'' which means that such convertible debt instruments, by their terms, may be settled either wholly or partially in cash upon conversion. Issuers of convertible debt instruments that may be settled wholly or partially in cash upon conversion are required to separately account for the liability and equity components in a manner reflective of the issuers' nonconvertible debt borrowing rate. The issuer must determine the estimated fair value of a similar debt instrument as of the date of the issuance without the conversion feature but inclusive of any other embedded features and assign that value to the debt component of the instrument, which results in a discount being recorded. The debt discount is subsequently accreted through interest expense to its par value over its expected life using the market rate at the date of issuance. The residual value between the initial proceeds and the value allocated to the debt is reflected in equity as additional paid in capital. Upon adoption on January 1, 2009, the provisions were retroactively applied, as required.

The adoption impacted the historical accounting for our 3.25% Notes which resulted in the adjustment of our Consolidated Statement of Income for the year ended December 31, 2008 and our Consolidated Balance Sheet as of December 31, 2008, as noted in the following tables. The reconciliation of Net income to Cash provided by operating activities for the year ended December 31, 2008 has been adjusted within our Consolidated Statement of Cash Flows for the retroactive application of this adoption.

	Year Ended December 31,	
	2008	2008
Consolidated Statement of Income	As Originally Presented	As Adjusted
	(In Thousands, Except Per Share Amounts)	
Loss on financing transactions	$ 538	$ 5,006
Total costs and expenses	2,856,567	2,861,035
Income before interest and taxes	133,222	128,754
Interest expense	(89,928)	(96,866)
Income before taxes	60,333	48,927
Income tax expense	(4,085)	(1,098)
Net income	56,248	47,829
Net income per share:		
Basic	$ 0.69	$ 0.58
Diluted	$ 0.68	$ 0.58

	December 31, 2008	December 31, 2008
Consolidated Balance Sheet	As Originally Presented	As Adjusted
	(In Thousands)	
Other noncurrent assets	$ 142,644	$ 139,186
Total assets	3,675,836	3,672,378
Long-term debt	1,463,643	1,310,181
Deferred taxes	117,268	177,294
Total noncurrent liabilities	2,135,049	2,041,613
Total liabilities	2,639,202	2,545,766
Additional capital	444,122	542,519
Retained earnings	640,496	632,077
Total shareholders' equity	1,036,634	1,126,612
Total liabilities and shareholders' equity	3,675,836	3,672,378

Earnings per Share

The number of shares used to calculate basic earnings per share is based on the weighted average number of our outstanding common shares during the respective periods. The number of shares used to calculate diluted earnings per share is based on the number of common shares used to calculate basic earnings per share plus the dilutive effect of stock options and other stock-based instruments held by our employees and directors during each period and debt securities currently convertible into our common stock, $0.625 par value ("Common Stock") during the period. The effect of dilutive securities in the amount of 1.2 million, 0.01 million and 0.8 million for the years ended December 31, 2009, 2008 and 2007, respectively, was excluded from the calculation of the diluted earnings per common share as such inclusion would result in antidilution.

The computation for basic and diluted earnings per share is based on the following per share information:

	Year Ended December 31, 2009	2008 As Adjusted	2007
	(In Thousands, Except Per Share Amounts)		
Numerator:			
Net income - numerator for basic	$ 104,433	$ 47,829	$ 94,098
Effect of convertible notes	174	188	200
Net income - numerator for diluted	$ 104,607	$ 48,017	$ 94,298
Denominator:			
Weighted average shares - denominator for basic	84,992	81,816	80,123
Effect of stock options/restricted stock	317	772	207
Effect of convertible notes	289	307	324
Adjusted weighted average shares - denominator for diluted	85,598	82,895	80,654
Net income per share:			
Basic	$ 1.23	$ 0.58	$ 1.17
Diluted	$ 1.22	$ 0.58	$ 1.17

2. Inventories

Inventories consisted of the following:

	December 31, 2009	December 31, 2008
	(In Thousands)	
Saleable coal	$ 179,081	$ 144,834
Raw coal	36,254	16,802
Subtotal coal inventory	215,335	161,636
Supplies inventory	54,491	71,532
Total inventory	$ 269,826	$ 233,168

Saleable coal represents coal ready for sale, including inventories designated for customer facilities under consignment arrangements of $43.7 million and $50.7 million at December 31, 2009 and 2008, respectively. Raw coal represents coal that generally requires further processing prior to shipment to the customer.

3. Other Current Assets

Other current assets are comprised of the following:

	December 31, 2009	December 31, 2008
	(In Thousands)	
Longwall panel costs	$ 12,041	$ 12,290
Deposits	133,794	59,648
Other	90,155	44,123
Total other current assets	$ 235,990	$ 116,061

Deposits consist primarily of funds placed in restricted accounts with financial institutions to collateralize letters of credit that support workers' compensation requirements, insurance and other obligations. As of December 31, 2009 and 2008, Deposits includes $46.0 million of funds pledged as collateral to support $45.1 million of outstanding letters of credit. In addition, Deposits at December 31, 2009 and 2008, includes $12.1 million and $13.0 million of United States Treasury securities supporting various regulatory obligations, respectively. During 2009, we posted $72.0 million of cash as collateral for an appeal bond in the Harman litigation which is included in Deposits (see Note 18 to the Notes to Consolidated Financial Statements for more information).

During 2009, we committed to the divestiture of certain mining equipment assets which are not part of our short-term mining plan. At December 31, 2009, the carrying amount of assets held for sale totaled $22.3 million and is included in Other current assets.

4. Property, Plant and Equipment

Property, plant and equipment is comprised of the following:

	December 31, 2009	December 31, 2008
	(In Thousands)	
Land, buildings and equipment	$ 2,631,886	$ 2,538,762
Mining properties owned in fee and leased mineral rights	851,704	779,932
Mine development	1,131,707	1,054,631
Total property, plant and equipment	4,615,297	4,373,325
Less accumulated depreciation, depletion and amortization	(2,270,527)	(2,075,629)
Property, plant and equipment, net	$ 2,344,770	$ 2,297,696

Land, buildings and equipment includes gross assets under capital leases of $12.9 million and $17.3 million at December 31, 2009 and 2008, respectively.

During 2009, we exchanged coal reserves and other assets with various third parties, recognizing a gain in Other revenue of $26.5 million (pre-tax). The acquired coal reserves and other assets were recorded in Property, plant and equipment at the fair value of the reserves and other assets surrendered.

During 2009, we sold our interest in certain coal reserves to a third party, recognizing a pre-tax gain of $7.1 million in Other revenue.

During 2008, we exchanged coal reserves and other assets with various third-parties, recognizing a gain in Other revenue of $32.4 million (pre-tax). The acquired coal reserves were recorded in Property, plant and equipment at the fair value of the reserves surrendered.

During 2008, we sold and leased-back certain mining equipment in several transactions for net proceeds of $41.3 million (see Note 13 for further details). During 2009, we had no material sale-leaseback transactions.

On August 27, 2009, a fire destroyed the Bandmill preparation plant at our Logan County resource group, located near Logan, West Virginia. We maintain property insurance which is expected to cover property losses incurred from the fire. We received $15.4 million in insurance proceeds during 2009. A replacement preparation plant is currently under construction, which is expected to be operational by the fall of 2010.

5. Pension Plans

Defined Benefit Pension Plans

We sponsor a qualified non-contributory defined benefit pension plan, which covers substantially all administrative and non-union employees. Based on a participant's entrance date to the plan, the participant may accrue benefits based on one of four benefit formulas. Two of the formulas provide pension benefits based on the employee's years of service and average annual compensation during the highest five consecutive years of service. The third formula credits certain eligible employees with flat dollar contributions based on years of service with Massey and years of service under the UMWA 1974 Pension Plan. The fourth formula provides benefits under a cash balance formula with contribution credits based on hours worked. This last formula has a guaranteed rate of return on contributions of 4% for all contributions after December 31, 2003. Funding for the plan is generally at the minimum contribution level required by applicable regulations. We made contributions of $15.0 million to the qualified plan during 2009. No contributions were made to the qualified plan during 2008.

An independent trustee holds the plan assets for the qualified defined benefit pension plan. The plan's assets include cash and cash equivalents, corporate and government bonds, preferred and common stocks and an investment in a group annuity contract. We have an internal investment committee ("Investment Committee") that sets investment policy, selects and monitors investment managers and monitors asset allocation. Diversification of assets is employed to reduce risk. The long-term target asset allocation is 65% for equity securities (including 50% domestic and 15% international) and 35% for cash and interest bearing securities. The investment policy is based on the assumption that the overall portfolio volatility will be similar to that of the target allocation. Given the volatility of the capital markets, strategic adjustments in various asset classes may be required to rebalance asset allocation back to its target policy. Investment fund managers are not permitted to invest in certain securities and transactions as outlined by the investment policy statements specific to each investment category without prior Investment Committee approval.

In January 2009, the Investment Committee decided to reduce the targeted asset allocation for an interim period for equity securities to 25% of current plan assets given the recent volatility and uncertainty in the equity securities market. The Investment Committee decided to invest $65 million of plan assets previously invested in equity securities in a fixed duration, fixed income strategy with an effective duration of approximately four years. The Investment Committee expects to rebalance the asset portfolio consistent with the long-term target asset allocation at the maturity of the fixed income, fixed duration strategy.

To develop the expected long-term rate of return on assets assumption, we considered the historical returns and the future expectations for returns for each asset class, as well as the long-term target asset allocation of the pension portfolio. This resulted in the selection of the 8.0% long-term rate of return on assets assumption for the year ended December 31, 2009. As we plan to return to our targeted asset allocation, we believe the expected long-term rate of return on plan assets of 8.0% continues to be appropriate.

The asset allocation for our funded qualified defined benefit pension plan at the end of 2009 and 2008, is as follows:

	Percentage of Plan Assets at Year End	
	December 31, 2009	December 31, 2008
Equity securities (domestic and international)	29.2%	54.2%
Debt securities	59.3%	33.7%
Other (includes cash, cash equivalents and a group annuity contract)	11.5%	12.1%
Total fair value of plan assets	100.0%	100.0%

Under the fair value hierarchy, our qualified defined benefit pension plan assets fall under *Level I - quoted prices in active markets* and *Level II - other observable inputs* (see Note 16 to the Notes to Consolidated Financial Statements for more information on the fair value hierarchy). The following table provides the fair value by each major category of plan assets at December 31, 2009:

	Level 1	Level 2
	(In Thousands)	
Equity securities	$ 49,461	$ -
Debt securities	-	145,563
Common/collective trust	-	19,697
Commingled short-term investment funds	-	13,270
Insurance contract	-	9,204

In addition to the qualified defined benefit pension plan noted above, we sponsor a nonqualified supplemental benefit pension plan for certain salaried employees. Participants in this nonqualified supplemental benefit pension plan accrue benefits under the same formula as the qualified defined benefit pension plan, however, where the benefit is capped by Internal Revenue Service ("IRS") limitations, this nonqualified supplemental benefit pension plan compensates for benefits in excess of the IRS limit. This supplemental benefit pension plan is unfunded, with benefit payments made by us.

The following table sets forth the change in benefit obligation, plan assets and funded status of both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan:

	Year Ended December 31, 2009	Year Ended December 31, 2008
	(In Thousands)	
Change in benefit obligation:		
Benefit obligation at the beginning of the period	$ 280,128	$ 252,237
Service cost	9,405	8,680
Interest cost	16,875	15,881
Actuarial loss	8,300	14,103
Benefits paid	(11,290)	(10,773)
Benefit obligation at the end of the period	303,418	280,128
Change in plan assets:		
Fair value at the beginning of the period	207,750	291,747
Actual return (loss) on assets	25,661	(73,286)
Company contributions	15,074	62
Benefits paid	(11,290)	(10,773)
Fair value of plan assets at end of period	237,195	207,750
Funded status	$ (66,223)	$ (72,378)
Qualified defined benefit pension plan, included in Pension obligation	$ (55,610)	$ (63,304)
Nonqualified supplemental benefit pension plan, included in Other noncurrent liabilities	(10,613)	(9,074)
Accrued Pension obligation recognized, net	$ (66,223)	$ (72,378)

The table below details the changes to Accumulated other comprehensive loss related to defined benefit pension plans:

	Year Ended December 31, 2009		Year Ended December 31, 2008	
	(In Thousands)			
	Net loss	Prior service cost	Net loss	Prior service cost
January 1 beginning balance	89,260	34	22,482	60
Changes to Accumulated other comprehensive loss	(11,254)	(25)	66,778	(26)
December 31 ending balance	$ 78,006	$ 9	$ 89,260	$ 34

We expect the estimated net loss and prior service cost for the defined benefit pension plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year to be $14.0 million and $5,000, respectively.

The assumptions used in determining pension benefit obligations for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan are as follows:

	December 31, 2009	December 31, 2008
Discount rates	6.00%	6.10%
Rates of increase in compensation levels	3.00%	4.00%

Net periodic pension expense for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan includes the following components:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
		(In Thousands)	
Service cost	$ 9,405	$ 8,680	$ 9,716
Interest cost	16,875	15,881	15,023
Expected return on plan assets	(16,359)	(22,852)	(22,427)
Recognized loss	17,447	770	4,068
Amortization of prior service cost	41	42	39
Net periodic pension expense	$ 27,409	$ 2,521	$ 6,419

The assumptions used in determining pension expense for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan are as follows:

	December 31, 2009	December 31, 2008	December 31, 2007
Discount rates	6.10%	6.50%	5.90%
Rates of increase in compensation levels	4.00%	4.00%	4.00%
Expected long-term rate of return on plan assets	8.00%	8.00%	8.00%

We expect that no contributions will be required in 2010 for the qualified defined benefit pension plan. We expect to make voluntary contributions of approximately $20 million in 2010. We also expect to voluntarily contribute approximately $0.3 million for benefit payments to participants in 2010 for the nonqualified supplemental benefit pension plan.

The following benefit payments from both the qualified defined benefit pension plan and the nonqualified supplemental benefit pension plan, which reflect expected future service, as appropriate, are expected to be paid from the plans:

	Expected Pension Benefit Payments
	(In Thousands)
2010	$ 13,151
2011	13,754
2012	14,672
2013	15,395
2014	16,316
Years 2015 to 2019	95,714

Multi-Employer Pension

Under labor contracts with the UMWA, certain operations make payments into two multi-employer defined benefit pension plan trusts established for the benefit of certain union employees. The contributions are based on tons of coal produced and hours worked. Such payments aggregated less than $600,000 in the years ended December 31, 2009 and 2008, and less than $400,000 in the year ended December 31, 2007.

Defined Contribution Plan

We currently sponsor a defined contribution pension plan for certain union employees. The plan is non-contributory and our contributions are based on hours worked. Contributions to this plan were approximately $50,000 for the three years ended December 31, 2009, 2008, and 2007, respectively.

Salary Deferral and Profit Sharing (401(K)) Plan

We also sponsor a salary deferral and profit sharing plan covering substantially all administrative and non-union employees. The maximum salary deferral rate is 75% of eligible pay, subject to IRS limitations. Prior to May 1, 2009, we contributed an amount equal to 30% of the first 10% of each participant's compensation contributed. Effective May 1, 2009, we reduced the fixed matching contribution to an amount equal to 10% of the first 10% of each participant's compensation contributed. Our contributions aggregated approximately $2.5 million, $4.6 million and $3.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

6. Debt

Our debt is comprised of the following:

	December 31, 2009	December 31, 2008 As Adjusted
	(In Thousands)	
6.875% senior notes due 2013, net of discount	$ 756,727	$ 756,041
3.25% convertible senior notes due 2015, net of discount	526,435	517,538
6.625% senior notes due 2010	21,949	21,949
2.25% convertible senior notes due 2024	9,647	9,647
4.75% convertible senior notes due 2023	-	70
Capital lease obligations	4,328	6,912
Total debt	1,319,086	1,312,157
Amounts due within one year	(23,531)	(1,976)
Total long-term debt	$ 1,295,555	$ 1,310,181

The weighted average effective interest rate of the outstanding borrowings was 7.3% at both December 31, 2009 and 2008.

Convertible Debt Securities

On January 1, 2009, new accounting guidance became effective relating to our 3.25% Notes, which was retroactively applied, as required. The impact to Earnings per share was a decrease of $0.13 and $0.10 for the years ended December 31, 2009 and 2008, respectively. We separately account for the liability and equity components in a manner reflective of our nonconvertible debt borrowing rate, which was determined to be 7.75% at the date of issuance of the 3.25% Notes. The discount associated with the 3.25% Notes is being amortized via the effective-interest method increasing the reported liability until the notes are carried at par value on their maturity date. We recognized $18.4 million and $6.9 million of non-cash interest expense for the amortization of the discount for the years ended December 31, 2009 and 2008, respectively.

Financing Transactions

On August 5, 2008, we commenced a consent solicitation and tender offer for any and all of the outstanding $335 million of 6.625% Notes and concurrently we commenced registered underwritten public offerings of convertible senior notes (the 3.25% Notes) and shares of Common Stock and announced our intention to use the proceeds of the offerings to purchase some or all of the 6.625% Notes in the tender offer and for general corporate purposes.

On August 19, 2008, we settled with holders of $311.5 million of the 6.625% Notes, representing approximately 93% of the outstanding 6.625% Notes, who tendered their 6.625% Notes pursuant to our consent solicitation and tender offer for the 6.625% Notes. The total consideration for these 6.625% Notes was $1,026.57 per $1,000 principal amount of the 6.625% Notes. The total consideration included a consent payment of $25 per $1,000 principal amount of the 6.625% Notes. In addition to the total consideration, holders also received interest which was accrued and unpaid since the previous interest payment date.

As a result of the consents of approximately 93% of the outstanding 6.625% Notes, we received the requisite consents to execute a supplemental indenture relating to the 6.625% Notes, which eliminated substantially all of the restrictive covenants in the 6.625% Notes' indenture.

On September 3, 2008, we settled with holders of an additional $1.6 million of the 6.625% Notes, who tendered their 6.625% Notes after the consent solicitation deadline. The total consideration for these 6.625% Notes was $1,001.57 per $1,000 principal amount of the 6.625% Notes. In addition to the total consideration, holders also received interest which was accrued and unpaid since the previous interest payment date.

We recognized charges totaling $15.2 million, including $1.9 million for the write-off of unamortized financing fees and $4.2 million for the unamortized interest rate swap termination payment (as discussed below) recorded in Interest expense, and $9.1 million for the debt consent solicitation and tender offer recorded in Loss on financing transactions.

Fair Value Hedge Adjustment

On December 9, 2005, we exercised our right to terminate our interest rate swap agreement, which was designated as a hedge against a portion of the 6.625% Notes. We paid a $7.9 million termination payment to the swap counterparty on December 13, 2005 ("Fair value hedge adjustment"). The termination payment was being amortized into Interest expense through November 15, 2010, the maturity date of the 6.625% Notes. As discussed in this Note under Financing Transactions above, on August 19, 2008, we settled with holders of approximately 93% of the outstanding 6.625% Notes that were tendered pursuant to our consent solicitation and tender offer for the 6.625% Notes. As a result of the acceptance of the consent solicitation and tender offer of the 6.625% Notes, the remaining balance of the Fair value hedge adjustment of $4.2 million was written off to Interest expense. For the twelve months ended December 31, 2008, $5.1 million of the Fair value hedge adjustment was recorded in Interest expense.

6.875% Notes

The 6.875% Notes are unsecured obligations ranking equally with all other unsecured senior indebtedness of ours and are guaranteed by substantially all of our current and future subsidiaries, (the "Guarantors"). Interest on the 6.875% Notes is payable on December 15 and June 15 of each year. We may redeem the 6.875% Notes, in whole or in part, for cash at any time on or after December 15, 2009 at a redemption price equal to 100% of the principal amount plus a premium declining ratably to par, plus accrued and unpaid interest. The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 6.875% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X).

The 6.875% Notes contain a number of significant restrictions and covenants that limit our ability and our subsidiaries' ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) restrict distributions from subsidiaries. We are currently in compliance with all covenants.

3.25% Notes

On August 12, 2008, we issued $690 million of 3.25% Notes in a registered underwritten public offering, resulting in net proceeds to us of approximately $674.1 million. The 3.25% Notes are guaranteed on a senior unsecured basis by the Guarantors. The subsidiaries not providing a guarantee of the 3.25% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X). The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The 3.25% Notes and the guarantees rank equally with all of our and the Guarantors' existing and future senior unsecured indebtedness and rank senior to all of our and the Guarantors' indebtedness that is expressly subordinated to the 3.25% Notes and the guarantees, but are effectively subordinated to all of our and the Guarantors' existing and future senior secured indebtedness to the extent of the value of the assets securing the indebtedness and to all liabilities of our subsidiaries that are not Guarantors.

The 3.25% Notes bear interest at a rate of 3.25% per annum, payable semi-annually in arrears on August 1 and February 1 of each year, beginning on February 1, 2009. The 3.25% Notes will mature on August 1, 2015, unless earlier repurchased by us or converted.

The 3.25% Notes are convertible in certain circumstances during certain periods at an initial conversion rate of 11.4106 shares of Common Stock per $1,000 principal amount of 3.25% Notes (which represented an initial conversion price of approximately $87.64 per share), subject to adjustment in certain circumstances. In the fourth quarter of 2008, we raised our quarterly dividend from $0.05 to $0.06 per share of Common Stock, which mandated a change in the conversion rate as of December 31, 2009. The conversion rate as of December 31, 2009 was 11.4420 shares of Common Stock per $1,000 principal amount of 3.25% Notes.

The 3.25% Notes are convertible under certain circumstances and during certain periods into (i) cash, up to the aggregate principal amount of the 3.25% Notes subject to conversion and (ii) cash, shares of Common Stock or a combination thereof, at our election in respect to the remainder (if any) of our conversion obligation. Subject to earlier repurchase, the 3.25% Notes will be convertible only in the following circumstances and to the following extent:

- during any calendar quarter, if the closing sale price of our shares of Common Stock for each of 20 or more trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter exceeds 130% of the conversion price in effect on the last trading day of the immediately preceding calendar quarter;

- during the five consecutive business days immediately after any five consecutive trading day period (the "note measurement period") in which the average trading price per $1,000 principal amount of 3.25% Notes was equal to or less than 97% of the average conversion value of the 3.25% Notes during the note measurement period;

- if we make certain distributions on our shares of Common Stock or engage in certain transactions; and

- at any time from, and including, February 1, 2015 until the close of business on the second business day immediately preceding August 1, 2015.

None of the 3.25% Notes are currently eligible for conversion.

The indenture governing the 3.25% Notes contains customary terms and covenants, including that upon certain events of default occurring and continuing, either the trustee for the 3.25% Notes or the holders of not less than 25% in aggregate principal amount of the 3.25% Notes then outstanding may declare the unpaid principal of the 3.25% Notes and any accrued and unpaid interest thereon immediately due and payable. In the case of certain events of bankruptcy, insolvency or reorganization relating to us, the principal amount of the 3.25% Notes together with any accrued and unpaid interest thereon will automatically become and be immediately due and payable.

During 2009 and 2008, we concluded open market purchases of our 3.25% Notes, reducing the net liability outstanding by $9.5 million ($11.9 million of principal amount less $2.4 million of debt discount) and $14.5 million ($19.0 million of principal amount less $4.5 million of debt discount) at a cost of $10.0 million and $10.4 million, respectively, plus accrued interest. After reversal of the equity component of these convertible notes of $0.3 million and $0.04 million in 2009 and 2008, respectively, a loss of $0.2 million was recorded in 2009 and a gain of $4.1 million was recorded in 2008, in Loss on financing transactions. Depending on market conditions and covenant restrictions, we may continue to make debt repurchases from time to time through open market purchases, private transactions or otherwise.

6.625% Notes

The 6.625% Notes are unsecured obligations of ours and rank equally with all other unsecured senior indebtedness. Interest is payable semiannually on May 15 and November 15 of each year. We may redeem the 6.625% Notes, in whole or in part, at any time on or after November 15, 2007 at a redemption price equal to 100% of the principal amount plus a premium declining ratably to par, plus accrued and unpaid interest. The 6.625% Notes are guaranteed by the Guarantors. The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 6.625% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X).

During January 2010, subsequent to the balance sheet date, we redeemed at par the remaining $21.9 million of our 6.625% Notes.

2.25% Notes

The 2.25% Notes are unsecured obligations of ours, rank equally with all other unsecured senior indebtedness and are guaranteed by the Guarantors. The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 2.25% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X). Interest is payable semiannually on April 1 and October 1 of each year. We registered the 2.25% Notes with the SEC for resale.

Holders of the 2.25% Notes may require us to purchase all or a portion of their notes for cash on April 1, 2011, 2014, and 2019, at a purchase price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest. In addition, if we experience certain specified types of fundamental changes on or before April 1, 2011, the holders may require us to purchase the notes for cash. We may redeem all or a portion of the 2.25% Notes for cash at any time on or after April 6, 2011, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest.

The 2.25% Notes are convertible during certain periods by holders into shares of Common Stock initially at a conversion rate of 29.7619 shares of Common Stock per $1,000 principal amount of 2.25% Notes (subject to adjustment upon certain events) under the following circumstances: (i) if the price of Common Stock issuable upon conversion reaches specified thresholds; (ii) if we redeem the 2.25% Notes; (iii) upon the occurrence of certain specified corporate transactions; or (iv) if the credit ratings assigned to the 2.25% Notes decline below certain specified levels. Regarding the thresholds in (i) above, holders may convert each of their notes into shares of Common Stock during any calendar quarter (and only during such calendar quarter) if the last reported sale price of Common Stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% of the conversion price per share of Common Stock. The conversion price is $33.60 per share. None of the 2.25% Notes are currently eligible for conversion. As of December 31, 2009, if all of the notes outstanding were eligible and were converted, we would have needed to issue 287,113 shares of Common Stock.

4.75% Notes

During May 2009, we redeemed at par the remaining $70,000 of the 4.75% Notes.

Asset-Based Lending Arrangement

On August 15, 2006, we entered into an amended and restated asset-based revolving credit facility, which provides for available borrowings, including letters of credit of up to $175 million, depending on the level of eligible inventory and accounts receivables. As of December 31, 2009, this facility supported $76.6 million of letters of credit and there were no outstanding borrowings under this facility. Any future borrowings under this facility will be variable rate borrowings, based on the applicable LIBOR rate for the specified rate reset period, plus an applicable margin. As of December 31, 2009, the applicable margin to LIBOR was 125 basis points.

The facility is collateralized by our accounts receivable, eligible coal inventories located at our facilities and on consignment at customers' facilities, and other intangibles. At December 31, 2009, total remaining availability was $98.4 million based on qualifying inventory and accounts receivable. The credit facility expires on August 15, 2011.

This facility contains a number of significant restrictions and covenants that limit our ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) make distributions from subsidiaries. This facility also contains financial covenants, which become operative only when our Average Excess Availability (as defined in the facility documents) is less than $30 million. These financial covenants include a Minimum Consolidated Fixed Charge Ratio of 1.00 to 1.00 and a minimum Consolidated Net Worth of $550 million under the terms of the ABL Facility (currently approximately $400 million as adjusted for Accounting Changes). We are currently in compliance with all covenants.

Debt Maturity

The aggregate amounts of scheduled long-term debt maturities assuming convertible notes are not eligible for conversion, including capital lease obligations, subsequent to December 31, 2009 are as follows:

	(In Thousands)
2010	$ 23,531
2011	2,655
2012	35
2013	760,035
2014	35
Beyond 2014*	680,696

* The 2.25% Notes in the amount of $9.6 million included herein may be redeemed at the option of the holders in 2011.

Total interest paid for the years ended December 31, 2009, 2008 and 2007, was \$75.5 million, \$70.3 million and \$75.7 million, respectively.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements including guarantees, operating leases, indemnifications, and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in the consolidated balance sheets, and, except for the operating leases, which are discussed in Note 13 to the Notes to Consolidated Financial Statements, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

From time to time we use bank letters of credit to secure our obligations for workers' compensation programs, various insurance contracts and other obligations. At December 31, 2009, we had \$121.6 million of letters of credit outstanding of which \$45.1 million was collateralized by \$46.0 million of cash deposited in restricted, interest bearing accounts pledged to issuing banks and \$76.5 million was issued under our asset based lending arrangement. No claims were outstanding against those letters of credit as of December 31, 2009.

We use surety bonds to secure reclamation, workers' compensation, wage payments and other miscellaneous obligations. As of December 31, 2009, we had \$401.1 million of outstanding surety bonds. These bonds were in place to secure obligations as follows: post-mining reclamation bonds of \$315.6 million, an appeal bond of \$72.0 million of cash as collateral in the Harman litigation (see Note 18 to the Notes to Consolidated Financial Statements for more information), and other miscellaneous obligation bonds of \$13.5 million. Outstanding surety bonds of \$46.1 million are secured with letters of credit.

Generally, the availability and market terms of surety bonds continue to be challenging. If we are unable to meet certain financial tests applicable to some of our surety bonds, or to the extent that surety bonds otherwise become unavailable, we would need to replace the surety bonds or seek to secure them with letters of credit, cash deposits, or other suitable forms of collateral.

7. Income Taxes

Income tax expense included in the Consolidated Statements of Income is as follows:

	Year Ended		
	December 31, 2009	December 31, 2008	December 31, 2007
		As Adjusted	
		(In Thousands)	
Current:			
Federal	\$ 14,309	\$ (4,597)	\$ 7,876
State and local	116	122	126
Total current	14,425	(4,475)	8,002
Deferred:			
Federal	15,374	4,593	24,593
State and local	3,033	980	2,810
Total deferred	18,407	5,573	27,403
Income tax expense	\$ 32,832	\$ 1,098	\$ 35,405

A reconciliation of Income tax expense calculated at the federal statutory rate of 35% to our Income tax expense on Net income is as follows:

	Year Ended December 31, 2009	Year Ended December 31, 2008 As Adjusted	Year Ended December 31, 2007
		(In Thousands)	
U.S. statutory federal tax expense	$ 48,043	$ 17,124	$ 45,326
Increase (Decrease) resulting from:			
State taxes	550	66	(116)
Non-deductible penalties	4,903	6,240	8,062
Percentage depletion	(33,918)	(45,671)	(33,501)
Non-deductible compensation	805	666	711
Non-deductible refinancing and exchange offer costs	-	-	(4,809)
Valuation allowance adjustment	18,747	29,104	31,343
Uncertain tax positions	-	-	(2,325)
Alternative minimum tax credit refund, net of adjustment	(5,988)	(4,770)	-
Refund from settlement of 2001 IRS audit	-	-	(4,609)
Other, net	(310)	(1,661)	(4,677)
Income tax expense	$ 32,832	$ 1,098	$ 35,405

Deferred taxes reflect the tax effects of differences between the amounts recorded as assets and liabilities for financial reporting purposes and the amounts recorded for income tax purposes. The tax effects of temporary differences giving rise to deferred tax assets and liabilities are as follows:

	Year Ended December 31, 2009	Year Ended December 31, 2008 As Adjusted
	(In Thousands)	
Deferred tax assets:		
Postretirement benefit obligations	$ 113,757	$ 117,106
Workers' compensation	23,707	24,682
Reclamation and mine closure	52,286	46,608
Alternative minimum tax credit carryforwards	113,977	104,782
Litigation	3,534	9,777
Deferred compensation	31,766	26,088
Federal net operating loss	110,415	115,897
State net operating loss	24,264	25,083
Other	33,032	35,718
Total deferred tax assets	506,738	505,741
Valuation allowance for deferred tax assets	(212,643)	(202,318)
Total deferred tax assets, net of valuation allowance	294,095	303,423
Deferred tax liabilities:		
Plant, equipment and mine development	(282,030)	(273,878)
Mining property and mineral rights	(145,063)	(131,308)
Convertible Debt	(51,725)	(60,026)
Deferred royalties	(11,298)	(9,863)
Other	(13,209)	(5,642)
Total deferred tax liablities	(503,325)	(480,717)
Deferred income taxes	$ (209,230)	$ (177,294)

Deferred tax assets include alternative minimum tax ("AMT") credits of $114.0 million and $104.8 million at December 31, 2009 and 2008, respectively, federal net operating loss carryforwards of $315.5 million and $331.1 million as of December 31, 2009 and 2008, respectively, and net state net operating loss ("NOL") carryforwards of $606.6 million and

$627.1 million as of December 31, 2009 and 2008, respectively. The AMT credits have no expiration date. Federal NOL carryforwards expire beginning in 2018 and ending in 2023. State NOL carryforwards expire beginning in 2009 and ending in 2023.

We have recorded a valuation allowance for a portion of deferred tax assets that management believes, more likely than not, will not be realized. These deferred tax assets include AMT credits, federal NOL and state NOL carryforwards that will likely not be realized at the maximum effective tax rate. The valuation allowance increased for the year ended December 31, 2009, primarily as a result of the increase in AMT credit carryforwards discussed above.

In June 2006, the FASB issued accounting guidance, effective January 1, 2007, to create a single model to address accounting for uncertainty in income tax positions. We increased Retained earnings by $5.2 million for the cumulative effect of adoption of this accounting guidance as of January 1, 2007. A tax position is initially recognized in the financial statements when it is more likely than not the position will be sustained upon examination by applicable taxing authorities. To determine if uncertainty exists in these income tax positions, such tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not to be realized upon ultimate settlement with the taxing authority assuming full knowledge of the position and all relevant facts. During the years ended December 31, 2009 and 2008 we had no uncertain income tax positions and therefore no unrecognized tax benefits. We accrue interest and penalties, if any, related to unrecognized tax benefits in Other noncurrent liabilities and recognize the related expense in Income tax expense. No interest related to unrecognized tax benefits was accrued for the year ended December 31, 2009. We accrued $0.8 million and $3.1 million in interest related to unrecognized tax benefits for the years ended December 31, 2008 and 2007.

We file income tax returns in the United States federal and various state jurisdictions, including West Virginia, Kentucky and Virginia. The Internal Revenue Service ("IRS") has examined our federal income tax returns, or statutes of limitations have expired for years through 2005. In the various states where we file state income tax returns, the state tax authorities have examined our state returns, or statutes of limitations have expired through 2004. Management believes that we have adequately provided for any income taxes that may ultimately be paid with respect to all open tax years.

8. Other Noncurrent Liabilities

Other noncurrent liabilities are comprised of the following:

	December 31, 2009	December 31, 2008
	(In Thousands)	
Reclamation (Note 9)	$ 193,361	$ 154,823
Other postretirement benefits (Note 10)	155,024	161,527
Workers' compensation and black lung (Note 11)	98,227	92,982
Other	91,446	81,502
Total other noncurrent liabilities	$ 538,058	$ 490,834

9. Reclamation

Our reclamation liabilities primarily consist of spending estimates related to reclaiming surface land and support facilities at both surface and underground mines in accordance with federal and state reclamation laws as defined by each mine permit. The obligation and corresponding asset are recognized in the period in which the liability is incurred.

We estimate our ultimate reclamation liability based upon detailed engineering calculations of the amount and timing of the future cash flows to perform the required work. We consider the estimated current cost of reclamation and apply inflation rates and a third-party profit, as necessary. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The discount rate applied is based on the rates of treasury bonds with maturities similar to the estimated future cash flow, adjusted for our credit standing.

The following table describes all changes to our reclamation liability:

	Year Ended December 31, 2009	Year Ended December 31, 2008
	(In Thousands)	
Reclamation liability at beginning of period	$ 186,180	$ 168,641
Accretion expense	13,991	11,844
Liability assumed/incurred	28,527	16,956
Liability disposed	(505)	(212)
Revisions in estimated cash flows	11,721	(6,092)
Payments	(5,352)	(4,957)
Reclamation liability at end of period	234,562	186,180
Less amount included in Other current liabilities	41,201	31,357
Total reclamation, included in Other noncurrent liabilities	$ 193,361	$ 154,823

10. Other Postretirement Benefits

We sponsor defined benefit health care plans that provide postretirement medical benefits to eligible union and non-union employees. To be eligible, retirees must meet certain age and service requirements. Depending on year of retirement, benefits may be subject to annual deductibles, coinsurance requirements, lifetime limits and retiree contributions. Service costs are accrued currently based on an annual study prepared by independent actuaries. These plans are unfunded.

Net periodic postretirement benefit cost includes the following components:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
		(In Thousands)	
Service cost	$ 3,913	$ 3,204	$ 3,668
Interest cost	10,017	8,845	8,467
Amortization of net loss	2,303	813	1,864
Amortization of prior service credit	(750)	(750)	(750)
Net periodic postretirement benefit cost	$ 15,483	$ 12,112	$ 13,249

The discount rate assumed to determine the net periodic postretirement benefit cost was 6.10%, 6.50% and 5.90% for the years ended December 31, 2009, 2008 and 2007, respectively.

The following table sets forth the change in benefit obligation of our postretirement benefit plans:

	Year Ended December 31, 2009	Year Ended December 31, 2008
	(In Thousands)	
Change in benefit obligation:		
Benefit obligation at the beginning of the period	$ 168,629	$ 147,733
Service cost	3,913	3,204
Interest cost	10,017	8,845
Plan amendment	(27,595)	-
Actuarial loss	13,951	15,538
Benefits paid	(6,827)	(6,691)
Benefit obligation at the end of the period	$ 162,088	$ 168,629
Accrued postretirement benefit obligation	$ 162,088	$ 168,629
Amount included in Payroll and employee benefits	7,064	7,102
Postretirement benefit obligation, included in Other noncurrent liabilities	$ 155,024	$ 161,527

Effective January 1, 2010, we consolidated our self-insured Medicare-age non-union retiree plans into one insured plan. We will pay 100% of the premium for fiscal year 2010 for each retiree. In subsequent years, retirees will be responsible for inflationary increases in the insurance premium. Further, members hired after January 1, 2010 will be required to pay 100% of the applicable Medicare Supplemental Plan monthly premium.

The table below details the changes to Accumulated other comprehensive loss related to our post retirement benefit plans:

	Year Ended			
	December 31, 2009		December 31, 2008	
	(In Thousands)			
	Net loss	Prior service credit	Net loss	Prior service credit
January 1 beginning balance	$ 29,111	$ (4,605)	$ 20,132	$ (5,063)
Changes to Accumulated other comprehensive loss	7,107	458	8,979	458
Plan Amendment	-	(16,833)	-	-
December 31 ending balance	$ 36,218	$ (20,980)	$ 29,111	$ (4,605)

We expect to recognize $3.1 million of prior service credit and $3.3 million of net actuarial loss in 2010.

The discount rates used to determine the benefit obligations were 6.00% and 6.10% for the years ended December 31, 2009 and 2008, respectively.

The assumed health care cost trend rates used to determine the benefit obligation as of the end of each year are as follows:

	December 31, 2009	December 31, 2008
Health care cost trend rate for next year *	8.3% / 8.6% / 7.0%	8.5% / 8.8% / 7.0%
Ultimate trend rate	4.50%	5.00%
Year that the rate reaches ultimate trend rate	2029	2019

* Initial trend rate for Pre-Medicare claims, initial trend rate for Medicare-Eligible, and intial trend rate for the Medicare Supplement Plan.

Assumed health care cost trend rates have a significant effect on the amounts reported for the medical plans. A one-percentage point change in assumed health care cost trend rates would have the following aggregate effects:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In Thousands)	
Effect on total of service and interest costs components	$ 1,799	$ (1,460)
Effect on accumulated postretirement benefit obligation	$ 20,215	$ (16,683)

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid in the periods noted:

	Expected Benefit Payments
	(In Thousands)
2010	$ 7,064
2011	7,763
2012	8,299
2013	8,916
2014	9,353
Years 2015 to 2019	52,527

Multi-Employer Benefits

Under the Coal Act, coal producers are required to fund medical and death benefits of certain retired union coal workers based on premiums assessed by the UMWA Benefit Funds. Based on available information at December 31, 2009, our obligation under the Coal Act was estimated at approximately $22.3 million, compared to our estimated obligation at December 31, 2008 of $19.2 million. The obligation was discounted using a 5.00% rate each year. We treat our obligation under the Coal Act as participation in a multi-employer plan and record the cost of our obligation as expense as payments are assessed. The expense related to this obligation for the years ended December 31, 2009, 2008 and 2007 totaled $1.9 million, $2.3 million and $1.3 million, respectively. The $1.3 million expense in 2007 was net of a $1.6 million refund from the UMWA Combined Benefit Fund ("CBF"). The refund was a result of the Tax Relief and Retiree Health Care Act of 2006 ("TRRHCA") enacted on December 20, 2006, which is detailed below.

The TRRHCA included important changes to the Coal Act that impacts all companies required to contribute to the CBF. Effective October 1, 2007, the Social Security Administration ("SSA") revoked all beneficiary assignments made to companies that did not sign a 1988 UMWA contract ("reachback companies") but their premium relief is phased-in. The reachback companies paid their full premium obligation in the current plan year that ended September 30, 2007. However, they paid only 55% and 40% of their plan year 2008 and 2009 assessed premiums, respectively. They will pay only 15% of their plan year 2010 assessed premiums. General United States Treasury money will be transferred to the CBF to make up the difference. After 2010, reachback companies will have no further obligations to the CBF, and transfers from the United States Treasury will cover all of the health care costs for retirees and dependents previously assigned to reachback companies. Some of our subsidiaries are considered reachback companies under the TRRHCA.

11. Workers' Compensation and Black Lung Benefits

Workers' compensation and black lung benefit obligation consisted of the following:

	December 31, 2009	December 31, 2008
	(In Thousands)	
Accrued self-insured black lung obligation	$ 53,145	$ 50,739
Workers' compensation (traumatic injury)	61,792	64,172
Total accrued workers' compensation and black lung	114,937	114,911
Less amount included in Other current liabilities	16,710	21,929
Workers' compensation & black lung in Other noncurrent liabilities	$ 98,227	$ 92,982

The amount of workers' compensation (traumatic liability) related to self-insurance was $61.1 million and $59.1 million at December 31, 2009 and 2008, respectively. Weighted average actuarial assumptions used in the determination of the self-insured portion of workers' compensation (traumatic injury) liability included a discount rate of 4.75% and 5.00% at December 31, 2009 and 2008, respectively, and the accumulated black lung obligation included a discount rate of 6.00% and 6.10% at December 31, 2009 and 2008, respectively.

A reconciliation of changes in the self-insured black lung obligation is as follows:

	Year Ended	
	December 31, 2009	December 31, 2008
	(In Thousands)	
Beginning of year accrued self-insured black lung obligation	$ 50,739	$ 53,412
Service cost	3,689	2,186
Interest cost	2,872	3,390
Actuarial gain	(1,535)	(6,524)
Benefit payments	(2,620)	(1,725)
Accrued self-insured black lung obligation	$ 53,145	$ 50,739

The table below details the changes to Accumulated other comprehensive loss related to black lung benefits:

	Year Ended December 31, 2009	Year Ended December 31, 2008
	(In Thousands)	
	Net gain	Net gain
January 1 beginning balance	$ (12,438)	$ (10,587)
Changes to Accumulated other comprehensive gain (loss)	1,854	(1,851)
December 31 ending balance	$ (10,584)	$ (12,438)

We expect to recognize $3.5 million of net actuarial gain in 2010.

Expenses for black lung benefits and workers' compensation related benefits include the following components:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
		(In Thousands)	
Self-insured black lung benefits:			
Service cost	$ 3,689	$ 2,186	$ 2,495
Interest cost	2,872	3,390	3,117
Amortization of actuarial gain	(4,575)	(3,489)	(3,194)
	1,986	2,087	2,418
Other workers' compensation benefits	26,816	27,965	30,842
	$ 28,802	$ 30,052	$ 33,260

Payments for benefits, premiums and other costs related to black lung and workers' compensation liabilities were $31.8 million, $24.0 million and $29.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

The actuarial assumptions used in the determination of self-insured black lung benefits expense included discount rates of 6.10%, 6.50% and 5.90% for the years ended December 31, 2009, 2008 and 2007, respectively.

Our self-insured black lung obligation is calculated using assumptions regarding future medical cost increases and cost of living increases. Federal black lung benefits are subject to cost of living increases. State benefits increase only until disability, and then remain constant. We assume a 6.50% annual medical cost increase and a 3.0% cost of living increase in determining our black lung obligation and the annual black lung expense. Assumed medical cost and cost of living increases significantly affect the amounts reported for our black lung expense and obligation. A one-percentage point change in each of assumed medical cost and cost of living trend rates would have the following effects:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In Thousands)	
Increase/decrease in medical cost trend rate:		
Effect on total of service and interest costs components	$ 242	$ (193)
Effect on accumulated black lung obligation	$ 1,567	$ (1,267)
Increase/decrease in cost of living trend rate:		
Effect on total service and interest cost components	$ 877	$ (699)
Effect on accumulated black lung obligation	$ 6,020	$ (4,903)

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid related to the self-insured black lung obligation:

	Expected Benefit Payments	
	(In Thousands)	
2010	$	2,818
2011		3,019
2012		3,210
2013		3,391
2014		3,573
Years 2015 to 2019		20,368

12. Stock Plans

We have stock incentive plans to encourage employees and nonemployee directors to remain with the Company and to more closely align their interests with those of our shareholders.

Description of Stock Plans

The Massey Energy Company 2006 Stock and Incentive Compensation Plan (the "2006 Plan"), which was approved by our shareholders and became effective on June 28, 2006 replaces the five stock-based compensation plans (the "Prior Plans") we had in place prior to the approval of the 2006 Plan, all of which had been approved by our shareholders. On May 19, 2009, the Company's shareholders approved adding 1,550,000 shares to our 2006 Plan. The shareholders also approved a limit to the maximum number of shares available for awards granted in any form provided under the 2006 Plan (other than stock options or SARS) to no more than 75% of the total number of issuable shares. The Prior Plans include the following:

- Massey Energy Company 1996 Executive Stock Plan, as amended and restated effective November 30, 2000 (the "1996 Plan"),
- Massey Energy Company 1997 Stock Appreciation Rights Plan, as amended and restated effective November 30, 2000 (the "SAR Plan"),
- Massey Energy Company 1999 Executive Performance Incentive Plan, as amended and restated effective November 30, 2000 (the "1999 Plan"),
- Massey Energy Company Stock Plan for Non-Employee Directors, as amended and restated effective May 24, 2005 (the "1995 Plan"), and
- Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors, as amended and restated effective May 24, 2005 (the "1997 Plan").

Stock-based compensation has been granted under the 2006 Plan and the Prior Plans in the manner described below. Issued and outstanding stock-based compensation has been granted to officers and certain key employees in accordance with the provisions of the 1996 Plan, the SAR Plan, the 1999 Plan, and the 2006 Plan. Issued and outstanding stock-based compensation has been granted to non-employee directors in accordance with the provisions of the 1995 Plan, the 1997 Plan and the 2006 Plan. The Compensation Committee of the Board of Directors administers the 1996 Plan, the 1999 Plan, the SAR Plan and the 2006 Plan. A committee comprised of non-participating board members administers the 1995 Plan and the 1997 Plan.

The 1996 Plan provided for grants of stock options and restricted stock. The 1999 Plan provided for grants of stock options, restricted stock, incentive awards and stock units. The SAR Plan provided for grants of SARs. The 1995 Plan provided for grants of restricted stock and restricted units. The 1997 Plan provided for grants of restricted stock. As of June 28, 2006, grants can no longer be made under the Prior Plans, except for the 1996 Plan, under which grants could no longer be made as of March 2, 2006. All awards previously granted that are outstanding under the Prior Plans will remain effective in accordance with the terms of their grant.

The aggregate number of shares of Common Stock that may be issued for future grant under the 2006 Plan as of December 31, 2009 was 2,704,145 shares, which was computed as the 3,500,000 shares specifically authorized in the 2006 Plan, plus the 1,550,000 shares added as part of the 2006 Plan amendments approved on May 19, 2009, less grants made in 2006, 2007, 2008 and 2009, plus the number of shares that (i) were represented by restricted stock or unexercised vested or unvested stock options that previously have been granted and were outstanding under the Prior Plans as of June 28, 2006 and (ii) expire or otherwise lapse, are terminated or forfeited, are settled in cash, or are withheld or delivered to us for tax

purposes at any time after June 28, 2006. The 2006 Plan provides for grants of stock options, SARs, restricted stock, restricted units, unrestricted stock and incentive awards.

Although we have not expressed any intent to do so, we have the right to amend, suspend, or terminate the 2006 Plan at any time by action of our Board of Directors. However, no termination, amendment or modification of the 2006 Plan shall in any manner adversely affect any award theretofore granted under the 2006 Plan, without the written consent of the participant. If a change in control were to occur (as defined in the plan documents), certain options may become immediately vested, but only upon termination of the option holder's service.

Accounting for Stock-Based Compensation

Total compensation expense recognized for stock-based compensation (equity awards) during the year ended December 31, 2009, 2008 and 2007 was $12.7 million, $13.9 million and $12.7 million, respectively. The total income tax benefit recognized in the consolidated statement of income for share based compensation arrangements during the year ended December 31, 2009, 2008 and 2007 was approximately $5.0 million, $5.4 million and $4.9 million, respectively. We recognize compensation expense on a straight-line basis over the vesting period for the entire award for any awards with graded vesting.

As of December 31, 2009 and 2008, there was $5.8 million and $8.4 million, respectively, of total unrecognized compensation cost related to stock options expected to be recognized over a weighted-average period of approximately 2.2 years. In the years ended December 31, 2009 and 2008, we also reflected $3.2 million, ($1.2) million, and $0.4 million, respectively, of excess tax benefit (expense) as a financing cash flow in the consolidated statement of cash flows resulting from the exercise of stock options.

Equity instruments

We have granted stock options to employees under the 2006 Plan, the 1999 Plan and the 1996 Plan. These options typically have a requisite service period of three to four years, though there are some awards outstanding with requisite service periods of one year up to four years. Vesting generally occurs ratably over the requisite service period. The maximum contractual term of stock options granted is 10 years.

We value stock options using the Black-Scholes valuation model, which employs certain key assumptions. We estimate volatility using both historical and market data over the term of the options granted. The dividend yield is calculated on the current annualized dividend payment and the stock price at the date of grant. The expected option life is based on historical data and exercise behavior. The risk-free interest rate is based on the zero-coupon Treasury bond rate in effect at the date of grant. The fair value of options granted during the three years ended December 31, 2009, 2008 and 2007 was calculated using the following assumptions:

	Years Ended December 31,		
Options Granted	2009	2008	2007
Number of shares underlying options	234,333	798,647	556,979
Contractual term in years	10	10	10
Assumptions used to estimate fair value:			
Expected volatility	59% - 66%	50% - 100%	46% - 50%
Weighted average volatility	66%	71%	50%
Expected option life in years	4.3	1.3 - 4.3	1.2 - 4.3
Dividend yield	0.7% - 1.8%	0.4% - 1.5%	0.6% - 0.7%
Risk-free interest rate	1.7% - 1.9%	0.9% - 3.1%	3.0% - 4.7%
Weighted-average fair value estimates at grant date:			
In thousands	$ 3,845	$ 6,820	$ 5,542
Fair value per share	$ 16.41	$ 8.54	$ 9.95

A summary of option activity under the plans for the year ended December 31, 2009 is presented below:

	Number of Options	Weighted average exercise price	Weighted average contractual term (years)	Aggregate Intrinsic Value
	(In Thousands, Except Exercise Price and Contractual Term)			
Outstanding at December 31, 2008	2,613	$ 25.81		
Granted	234	32.95		
Exercised	(515)	21.96		
Forfeited/expired	(279)	29.74		
Outstanding at December 31, 2009	2,053	$ 27.05	6.5	$30,716
Exercisable at December 31, 2009	1,351	$ 27.91	5.4	$19,054

We received $11.3 million, $16.5 million and $4.0 million in cash proceeds from the exercise of stock options for the years ended December 31, 2009, 2008 and 2007, respectively. The intrinsic value of stock options exercised was $7.5 million, $18.4 million and $4.5 million for the years ended December 31, 2009, 2008 and 2007, respectively.

We have granted restricted stock to our employees under the 2006 Plan and 1999 Plan and to non-employee directors under the 1995 Plan and 1997 Plan. Restricted stock awards are valued on the date of grant based on the closing value of our stock. As of December 31, 2009, there was $13.4 million of unrecognized compensation cost related to restricted stock expected to be recognized over the next three years. Unearned compensation is recorded on a net basis in Additional capital.

A summary of the status of restricted stock at December 31, 2009, and changes for the year then ended is presented below:

(Shares In Thousands)	Shares	Weighted average grant date fair value
Unvested at December 31, 2008	595	$ 28.64
Granted	282	$ 33.11
Vested	(272)	$ 25.77
Forfeited	(29)	$ 22.92
Unvested at December 31, 2009	576	$ 28.52

The fair value of restricted stock vested during the years ended December 31, 2009, 2008 and 2007 was $7.0 million, $6.7 million and $3.8 million, respectively.

Liability instruments

We use the fair value method to recognize compensation cost associated with SARs. At December 31, 2009 there were 150,000 SARs outstanding and exercisable. The weighted average exercise price of these SARs was $36.50 per SAR; the weighted average contractual term was 5.3 years. At both December 31, 2008 and 2007, there were 262,500 vested SARs outstanding and exercisable. The weighted average exercise price of these SARs was $29.19 per SAR; the weighted average contractual term was 3.8 years.

We also issue stock incentive units, which are classified as liabilities. They are settled with a cash payment for each unit vested, equal to the fair market value of Common Stock on the vesting date.

	For the years ended December 31, 2009	2008
Awarded	218,364	399,687
Settled	150,829	131,981
Settlement amount (in millions)	$ 5.2	$ 2.4

13. Lease Obligations

We lease certain mining and other equipment under various lease agreements. Certain of these leases provide options for the purchase of the property at the end of the initial lease term, generally at its then fair market value, or to extend the terms at its then fair rental value. Certain of these leases contain financial or other non-performance covenants that may require an accelerated buyout of the lease if the covenants are violated. Rental expense for the years ended December 31, 2009, 2008 and 2007 was $81.8 million, $53.1 million and $39.7 million, respectively.

During 2008 and 2007 we sold and leased-back certain mining equipment. We received net proceeds of $41.3 million and $13.1 million, for the years ended December 31, 2008 and 2007, respectively, resulting in net deferred gains of $2.4 million and $1.2 million for the years ended December 31, 2008 and 2007, respectively. The gains are being recognized ratably over the term of the leases, which range from 3.5 to 7 years. At lease termination, the leases contain renewal and purchase options at an amount approximating fair value. The leases are being accounted for as operating leases. We did not engage in any material sale-leaseback transactions in 2009.

The following presents future minimum rental payments, by year, required under leases with initial terms greater than one year, in effect at December 31, 2009:

	Capital Leases	Operating Leases
	(In Thousands)	
2010	$ 1,759	$ 75,412
2011	2,705	64,827
2012	35	54,477
2013	35	37,533
2014	35	12,602
Beyond 2014	-	7,601
Total minimum lease payments	4,569	$ 252,452
Less imputed interest	241	
Present value of minimum capital lease payments	$ 4,328	

14. Concentrations of Credit Risk and Major Customers

We are engaged in the production of coal for the utility industry, steel industry and industrial markets. The following chart lists the percentage of each type of Produced coal revenue generated by market:

	For the years ended December 31,		
	2009	2008	2007
Utility coal	62%	53%	60%
Metallurgical coal	30%	37%	30%
Industrial coal	8%	10%	10%

Our mining operations are conducted in southern West Virginia, eastern Kentucky and western Virginia. We market our produced and purchased coal to customers in the United States and in international markets, including Canada and various European and Asian countries. For the years ended December 31, 2009, 2008, and 2007 approximately 20%, 30%, and 16%, respectively, of Produced coal revenue was attributable to sales to customers outside of the United States.

For the years ended December 31, 2009 and 2008, approximately 19% and 11%, respectively, of Produced coal revenue was attributable to sales to Constellation Energy Commodities Group, Inc. For the year ended December 31, 2007, approximately 11% of Produced coal revenue was attributable to sales to affiliates of American Electric Power Company, Inc. At December 31, 2009, approximately 61%, 19% and 20% of Trade receivables represents amounts due from utility customers, metallurgical customers and industrial customers, respectively, compared with 75%, 13% and 12%, respectively, as of December 31, 2008.

Our Trade and other accounts receivable are subject to potential default by customers. In prior years, certain of our customers have filed for bankruptcy resulting in bad debt charges. In an effort to mitigate credit-related risks in all customer classifications, we maintain a credit policy, which requires scheduled reviews of customer creditworthiness and continuous monitoring of customer news events that might have an impact on their financial condition. Negative credit performance or events may trigger the application of tighter terms of sale, requirements for collateral or guarantees or, ultimately, a suspension of credit privileges. We also insure the receivables of certain customers whose financial condition puts them at a greater risk of loss; recoveries under this insurance program are subject to 10% co-insurance and a $5 million deductible. We establish bad debt reserves to specifically consider customers in financial difficulty and other potential receivable losses. In establishing the reserve, we consider the financial condition of individual customers and probability of recovery in the event of default. We charge off uncollectible receivables once legal potential for recovery is exhausted. See Note 18 for a discussion of certain customer disputes.

15. Derivative Instruments

Upon entering into each coal sales and coal purchase contract, we evaluate each of our contracts to determine if they qualify for the NPNS exception prescribed by current accounting guidance. We use purchase coal contracts to supplement our produced and processed coal in order to provide coal to meet customer requirements under sales contracts. The majority of our contracts qualifiy for the NPNS exception and therefore are not reflected in the Consolidated Balance Sheets and Consolidated Statements of Income. For those contracts that do not qualify for the NPNS exception, at inception or at some point during the duration of the contract, the contracts are required to be accounted for as derivative instruments and must be recognized as assets or liabilities and measured at fair value. Those contracts that do not qualify for the NPNS exception have not been designated as cash flow or fair value hedges and, accordingly, the net change in fair value is recorded in current period earnings. As of December 31, 2009, there were approximately 1.0 million and 1.1 million tons outstanding under these coal purchase and coal sales contracts, respectively. As of December 31, 2008, there were approximately 1.8 million and 2.2 million tons outstanding under these coal purchase and coal sales contracts, respectively. We have recorded a net gain of $37.6 million ($53.1 million of unrealized gains due to fair value measurement adjustments and $15.5 million of realized losses due to settlements on existing contracts) for the year ended December 31, 2009, and $22.6 million of unrealized losses due to fair value measurement adjustments for the year ended December 31, 2008, related to coal sales and purchase contracts that did not qualify for the NPNS exception in the Consolidated Statements of Income under the caption (Gain) loss on derivative instruments. An asset of $30.6 million is included in Other current assets in the Consolidated Balance Sheet as of December 31, 2009. A liability of $22.6 million is included in Other current liabilities in the Consolidated Balance Sheet as of December 31, 2008. The fair values of our purchases and sales derivative contracts have been aggregated in Other current assets and Other current liabilities as of December 31, 2009 and 2008, respectively.

We are exposed to certain risks related to coal price volatility. The purchases and sales contracts we enter into allow us to mitigate a portion of the underlying risk associated with coal price volatility.

16. Fair Value of Financial Instruments

Financial and non-financial assets and liabilities that are required to be measured at fair value must be categorized based upon the levels of judgment associated with the inputs used to measure their fair value. Hierarchical levels – directly related to the amount of subjectivity associated with the inputs used to determine the fair value of financial assets and liabilities – are as follows:

- Level 1 – Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.
- Level 2 – Inputs (other than quoted prices included in Level 1) are either directly or indirectly observable for the assets or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.
- Level 3 – Inputs reflect management's best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

Each major category of financial assets and liabilities measured at fair value on a recurring basis are categorized in the tables below based upon the lowest level of significant input to the valuations.

	December 31, 2009 (In Thousands)			
	Level 1	Level 2	Level 3	Total
Fixed income securities	$ 12,147	$ -	$ -	$ 12,147
Money market funds	763,573	-	-	763,573
Short-term investment	-	-	10,864	10,864
Derivative instruments	-	30,564		30,564
Total securities	$ 775,720	$ 30,564	$ 10,864	$ 817,148

Fixed income securities and money market funds

All investments in money market funds are cash equivalents or deposits pledged as collateral and are invested in AAA prime money market funds and Treasury-backed funds. Included in the money market funds are $46.0 million of funds pledged as collateral to support $45.1 million of outstanding letters of credit and $72.0 million of cash held as collateral for an appeal bond in the Harman litigation. All fixed income securities are deposits, consisting of obligations of the U.S. Treasury, supporting various regulatory obligations. See Note 3 to the Notes to Consolidated Financial Statements for more information on deposits.

Short-Term Investment

Short-term investment is comprised of an investment in Primary Fund, a money market fund that has suspended redemptions and is being liquidated. We have determined that our investment in the Primary Fund no longer meets the definition of a security, within the scope of current accounting guidance, since the equity investment no longer has a readily determinable fair value. Therefore, the investment has been classified as a short-term investment, subject to the cost method of accounting, on our Consolidated Balance Sheet. This classification as a short-term investment is based on our assessment of each of the individual securities that make up the underlying portfolio holdings in the Primary Fund, which primarily consisted of commercial paper and discount notes having maturity dates within the next 12 months, and the stated notifications from the Primary Fund that they expect to liquidate substantially all of their holdings and make distributions within a year.

Assets Measured at Fair Value on a Recurring Basis Using Significant Unobservable Inputs (Level 3):

(In Thousands)		Short-term Investments
Balance at December 31, 2008	$	39,383
Transfers out of Level 3, net		(28,519)
Change in fair value included in earnings		-
Balance at December 31, 2009	$	10,864
Losses included in earnings attributable to the change in unrealized losses relating to assets still held at December 31, 2009	$	-

We received distributions from the Primary Fund in the amount of $28.5 million during 2009, leaving an investment balance of $10.9 million, net of an estimated $6.5 million loss recorded in 2008. During January 2010, subsequent to the balance sheet date, we receive a distribution in the amount of $14.6 million.

Derivative Instruments

Certain of our coal sales and coal purchase contracts that do not qualify for the NPNS exemption at inception or at some point during the life of the contract are accounted for as derivative instruments and are required to be recognized as assets or liabilities and measured at fair value. To establish fair values for these contracts, we use bid/ask price quotations obtained from independent third-party brokers. We also consider the risk of nonperformance of or nonpayment by the counterparties when determining the fair values for these contracts by evaluating the credit quality and financial condition of each counterparty. We could experience difficulty in valuing our derivative instruments if the number of third-party brokers should decrease or market liquidity is reduced. See Note 15 to the Notes to Consolidated Financial Statements for more information.

Fair Value Option

The following methods and assumptions were used to estimate the fair value of those financial instruments that are not required to be carried at fair value within our Consolidated Balance Sheets:

Short-term debt: The carrying amount reported in the Consolidated Balance Sheets for short-term debt approximates its fair value due to the short-term maturity of these instruments.

Long-term debt: The fair values of long-term debt are estimated using the most recent market prices quoted on or before December 31, 2009.

The carrying amounts and fair values of these financial instruments are presented in the table below. The carrying value of the 3.25% Notes reflected in Long-term debt in the table below reflects the full face amount of $659.1 million, which has been adjusted in the Consolidated Balance Sheets for the adoption of new accounting guidance, which became effective January 1, 2009 (see Note 6 to the Notes to Consolidated Financial Statements for more information).

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In Thousands)			
Short-term debt	$ 23,531	$ 23,465	$ 1,976	$ 1,976
Long-term debt	$ 1,428,710	$ 1,348,699	$ 1,462,666	$ 931,011

17. Common Stock Issuance

On August 12, 2008, we completed a registered underwritten public offering of 4,370,000 shares of Common Stock, which included 2,874,800 shares of our Treasury stock, at a public offering price of $61.50 per share, resulting in proceeds to us of $258.2 million, net of underwriting fees. As discussed in Note 6, we used these proceeds and the proceeds of the concurrent convertible notes offering to purchase a portion of the 6.625% Notes in connection with the 6.625% Notes consent solicitation and tender offer and for general corporate purposes.

18. Contingencies

Harman

In December 1997, A.T. Massey's then subsidiary, Wellmore Coal Corporation ("Wellmore"), declared force majeure under its coal supply agreement with Harman Mining Corporation ("Harman") and reduced the amount of coal to be purchased from Harman. On October 29, 1998, Harman and its sole shareholder sued A.T. Massey and five of its other subsidiaries (the "Massey Defendants") in the Circuit Court of Boone County, West Virginia, alleging that the Massey Defendants tortiously interfered with Wellmore's agreement with Harman, causing Harman to go out of business. On August 1, 2002, the jury awarded the plaintiffs $50 million in compensatory and punitive damages. On October 24, 2006, the Massey Defendants timely filed their Petition for Appeal to the Supreme Court of Appeals of West Virginia ("WV Supreme Court"). On November 21, 2007, the WV Supreme Court issued a 3-2 majority opinion reversing the judgment against the Massey Defendants and remanding the case to the Circuit Court of Boone County with directions to enter an order dismissing the case, with prejudice, in its entirety. The Harman plaintiffs filed motions asking the WV Supreme Court to conduct a rehearing in the case. On January 24, 2008, the WV Supreme Court decided to rehear the case, which was re-argued on March 12, 2008. On April 3, 2008, the WV Supreme Court again reversed the judgment against the Massey Defendants and remanded the case with direction to enter an order dismissing the case, with prejudice, in its entirety. In July 2008, the Harman plaintiffs petitioned the United States Supreme Court (the "U.S. Supreme Court") to review the WV Supreme Court's dismissal of their claims.

In December 2008, the U.S. Supreme Court agreed to review the case. The U.S. Supreme Court granted review based on the question of whether a justice of the WV Supreme Court should have recused himself from the appeal. The U.S. Supreme Court found that the justice should have recused himself and ruled on June 8, 2009 that the matter should be reheard by the WV Supreme Court. The WV Supreme Court heard oral arguments on the matter on September 8, 2009, and reversed the lower court's decision on November 12, 2009. The Harman plaintiffs subsequently requested that the WV Supreme Court reconsider its decision. The WV Supreme Court has yet to rule on that request. We were required to post $72 million of cash as collateral for an appeal bond prior to the rehearing on September 8, 2009, and the WV Supreme Court has not released that appeal bond while the request for reconsideration has been outstanding. Because the West Virginia Supreme Court rarely grants requests for reconsideration, we believe at this time that this matter will be resolved without a material adverse impact on our cash flows, results of operations or financial condition.

West Virginia Flooding

Since July 2001, we and nine of our subsidiaries were sued in 17 consolidated civil actions filed in the Circuit Courts of Boone, Fayette, Kanawha, McDowell, Mercer, Raleigh and Wyoming Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding on or about July 8, 2001. Along with 32 other consolidated cases not involving us or our subsidiaries, these cases covered approximately 1,800 plaintiffs seeking unquantified compensatory and punitive damages against approximately 100 defendants. The WV Supreme Court transferred all 49 cases (the “Referred Cases”) to the Circuit Court of Raleigh County, West Virginia, to be handled by a mass litigation panel, which consists of six circuit court judges who have extensive experience with mass litigation. In December 2009, the cases against us and our subsidiaries were settled with no material adverse impact on our cash flows, results of operations or financial condition. We had insurance coverage applicable to these items.

Since August 2004, five of our subsidiaries have been sued in six civil actions filed in the Circuit Courts of Boone, McDowell, Mingo, Raleigh, Summers and Wyoming Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding on or about May 2, 2002. These complaints cover approximately 350 plaintiffs seeking unquantified compensatory and punitive damages from approximately 35 defendants. During a hearing held on February 2, 2009, the Circuit Court of Raleigh County dismissed one of these cases without prejudice for failure to prosecute. The order dismissing the case was entered on March 2, 2009 and the plaintiffs have one year from the entry of that order to re-file their claim.

Since May 2006, we and twelve of our subsidiaries have been sued in three civil actions filed in the Circuit Courts of Logan and Mingo Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding between May 30 and June 4, 2004. Four of our subsidiaries have been dismissed without prejudice from one of the Logan County cases. These complaints cover approximately 425 plaintiffs seeking unquantified compensatory and punitive damages from approximately 52 defendants.

We believe the cases that have not been settled will be resolved without a material adverse impact on our cash flows, results of operations or financial condition.

West Virginia Trucking

Since January 2003, an advocacy group and residents in Boone, Kanawha, Mingo and Raleigh Counties, West Virginia, filed 17 suits in the Circuit Courts of Kanawha and Mingo Counties, West Virginia, against twelve of our subsidiaries. Plaintiffs alleged that defendants illegally transported coal in overloaded trucks, causing damage to state roads, thereby interfering with plaintiffs’ use and enjoyment of their properties and their right to use the public roads. Plaintiffs seek injunctive relief and compensatory and punitive damages. The WV Supreme Court referred the consolidated lawsuits, and similar lawsuits against other coal and transportation companies not involving our subsidiaries, to the Circuit Court of Lincoln County, West Virginia, to be handled by a mass litigation panel judge. Plaintiffs filed motions requesting class certification. On June 7, 2007, plaintiffs voluntarily dismissed their public nuisance claims seeking monetary damages for road and bridge repairs. Defendants filed a motion requesting that the mass litigation panel judge recommend to the WV Supreme Court that the cases be sent back to the circuit courts of origin for resolution. That motion was verbally denied as to those cases in which our subsidiaries are defendants, and a class certification hearing was held on October 21, 2009. To date, no decision has been rendered by the WV Supreme Court on the class certification issues. Plaintiffs also agreed to an order limiting any damages for nuisance to two years prior to the filing of any suit. A motion to dismiss any remaining public nuisance claims was resisted by plaintiffs and argued at hearings on December 14, 2007 and June 25, 2008. No date has been set for trial. We believe we have insurance coverage applicable to these items and that they will be resolved without a material adverse impact on our cash flows, results of operations or financial condition.

Well Water Suits

Since September 2004, approximately 738 plaintiffs have filed approximately 400 suits against us and our subsidiary, Rawl Sales & Processing Co., in the Circuit Court of Mingo County, West Virginia (“Mingo Court”), for alleged property damage and personal injuries arising out of slurry injection and impoundment practices allegedly contaminating plaintiffs’ water wells. Plaintiffs seek injunctive relief and compensatory damages in excess of $170 million and unquantified punitive damages. Specifically, plaintiffs are claiming that defendants’ activities during the period of 1978 through 1987 rendered their property valueless and request monetary damages to pay, inter alia, the value of their property and future water bills. In addition, many plaintiffs are also claiming that their exposure to the contaminated well water caused neurological injury or physical injury, including cancers, kidney problems and gall stones. Finally, all plaintiffs claimed entitlement to medical monitoring for the next 30 years and have requested unliquidated compensatory damages for pain and suffering, annoyance and inconvenience and legal fees. On April 30, 2009, the Mingo Court held a mandatory settlement conference. At that settlement conference, all plaintiffs agreed to settle and dismiss their medical monitoring claims. Additionally, 180 plaintiffs agreed to settle all of their remaining claims and be dismissed from the case. The Mingo Court is currently considering whether to dismiss the claims of an additional 179 plaintiffs who did not attend the mandatory settlement conference. All settlements to date will be funded by insurance proceeds. The plaintiffs are challenging the medical monitoring settlement. A motion to enforce the medical monitoring settlement has been filed. No ruling has been made. There are currently 556 plaintiffs remaining. As a result of the recent disqualification of Judge Thornsbury, on account of having been engaged as a lawyer in the 1980s, on a matter on behalf of a Massey subsidiary adverse to one of the plaintiffs, the WV Supreme Court has reassigned all the cases to Judge Thomas Evans. Judge Evans has not set a trial date. Recently, Judge Evans requested the WV Supreme Court of West Virginia refer the cases to the statutory mass litigation panel for further proceedings. The WV Supreme Court has not ruled on the request.

Beginning in December 2008, we and certain of our subsidiaries along with several other companies were sued in numerous actions in Boone County, West Virginia involving approximately 300 plaintiffs alleging well water contamination resulting from coal mining operations. Mediation is scheduled for March 29, 2010.

We do not believe there was any contamination caused by our activities or that plaintiffs suffered any damage and, therefore, we do not believe we have a probable loss related to this matter. We plan to vigorously contest these claims. We believe that we have insurance coverage applicable to these matters and have initiated litigation against our insurers to establish that coverage. At this time, we believe that the litigation by the plaintiffs will be resolved without a material adverse impact on our cash flows, results of operations or financial condition.

Surface Mining Fills

Since September 2005, three environmental groups sued the United States Army Corps of Engineers ("Corps") in the United States District Court for the Southern District of West Virginia (the "District Court"), asserting the Corps unlawfully issued permits to four of our surface mines to construct mining fills. The suit alleges the Corps failed to comply with the requirements of both Section 404 of the Clean Water Act and the National Environmental Policy Act, including preparing environmental impact statements for individual permits. We intervened in the suit to protect our interests. On March 23, 2007, the District Court rescinded four of our subsidiaries' permits, resulting in the temporary suspension of mining at these surface mines. We appealed that ruling to the United States Court of Appeals for the Fourth Circuit (the "Fourth Circuit Court"). On April 17, 2007, the District Court partially stayed its ruling, permitting mining to resume in certain fills that were already under construction. On June 14, 2007, the District Court issued an additional ruling, finding the Corps improperly approved placement of sediment ponds in streams below fills on the four permits in question. The District Court subsequently modified its ruling to allow these ponds to remain in place, as the ponds and fills have already been constructed. The District Court's ruling could impact the issuance of permits for the placement of sediment ponds for future operations. If the permits for the fills or sediment ponds are ultimately held to be unlawfully issued, production could be affected at these surface mines, and the process of obtaining new Corps permits for all surface mines could become more difficult. We appealed both rulings to the Fourth Circuit Court. On February 13, 2009, the Fourth Circuit Court reversed the prior rulings of the District Court and remanded the matter for further proceedings. On March 30, 2009, the plaintiffs requested that the Fourth Circuit Court reconsider the case. The request was denied on May 20, 2009. On August 26, 2009, the plaintiffs filed their request with the U.S. Supreme Court to review the Fourth Circuit Court's decision. Our subsidiaries' response is due March 9, 2010; the U.S. Supreme Court then will decide whether to accept the case for review.

Customer Disputes

We have customers who claim they did not receive, or did not timely receive, all of the coal required to be shipped to them during 2008 ("unshipped tons"). In such cases, it is typical for a customer and coal producer to agree upon a schedule for shipping unshipped tons in subsequent years. A few of our customers, however, filed claims or notified us of potential claims for cover damages, which damages are equal to the difference between the contract price of the coal that was not delivered and the market price of replacement coal or comparable quality coal. We have resolved the majority of these claims in 2009 and early 2010, while discussions with other customers remain ongoing.

We believe we have strong defenses to the remaining claims for cover damages. In many cases, there was untimely or insufficient delivery of railcars by the rail carrier or the customer. In other cases, factors beyond our control caused production or shipment problems. Additionally, we believe that certain customers previously agreed to accept unshipped tons in subsequent years. We believe that all of these factors, and other factors, provide defenses to claims or potential claims for unshipped tons.

Separately, we are currently in litigation with one customer regarding disagreements over other contract matters. Specifically, we have a dispute with one customer regarding whether or not binding contracts for the sale of coal were reached. We maintain that this customer improperly terminated a signed, higher-priced contract; the customer argues that it was only required to purchase coal under a purported agreement reached by email. On February 12, 2010, we received a decision from an arbitration panel awarding this customer $10.5 million on the grounds that the purported agreement by email was valid and that the higher-priced contract was invalid. We believe that the arbitration panel's decision as to the validity of the higher-priced contract was beyond the panel's jurisdiction and have challenged that decision in federal court. We will vigorously pursue this challenge and do not consider this loss as probable.

We believe that we have strong defenses to the other claims and potential claims and further feel that many or all of these claims may be resolved without trial. We have recorded an accrual for our best estimate of probable losses related to these matters. While we believe that all of these matters discussed above will be resolved without a material adverse impact on our cash flows, results of operations or financial condition, it is reasonably possible that our judgments regarding some or all of these matters could change in the near term. We believe the aggregate exposure related to these claims in excess of our accrual is up to $62 million of charges that would affect our future operating results and financial position.

Spartan Unfair Labor Practice Matter & Related Age Discrimination Class Action

In 2005, the United Mine Workers of America ("UMWA") filed an unfair labor practice charge with the National Labor Relations Board ("NLRB") alleging that one of our subsidiaries, Spartan Mining Company ("Spartan"), discriminated on the basis of anti-union animus in its employment offers. The NLRB issued a complaint and an NLRB Administrative Law Judge ("ALJ") issued a recommended decision making detailed findings that Spartan committed a number of unfair labor practice violations and awarding, among other relief, back pay damages to union discriminatees. On September 30, 2009, the NLRB upheld the ALJ's recommended decision. Spartan has appealed the NLRB's decision to the United States Court of Appeals for the Fourth Circuit. We have no insurance coverage applicable to this unfair labor practice matter; however, its resolution is not expected to have a material impact on our cash flows, results of operations or financial condition.

On November 1, 2006, a class action age discrimination civil case was filed in West Virginia's Fayette County Circuit Court. The suit alleged that Spartan discriminated against employment applicants on the basis of age. The class includes approximately 229 individuals, 82 of whom are also union discriminatees at issue in the ALJ's decision. The plaintiffs made claims for back pay, front pay, punitive damages, and other compensatory damages, plus attorney fees. We have insurance coverage applicable to the class action and, on July 28, 2009, the parties executed a Class Settlement Agreement establishing a settlement fund from which all class claims and attorney fees were paid. The majority of the settlement proceeds were paid by the insurer, with Spartan's portion of the settlement limited to its insurance deductible of $1 million dollars plus applicable employer payroll taxes for back pay allocated to class plaintiffs. On October 30, 2009, a final hearing was held at which the parties' settlement agreement was approved. This matter concluded without a material impact on our cash flows, results of operations or financial condition.

Other Legal Proceedings

We are parties to a number of other legal proceedings, incident to our normal business activities. These include contract dispute, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates we do not believe that any liability arising from these matters individually or in the aggregate should have a material adverse impact upon our consolidated cash flows, results of operations or financial condition. It is possible, however, that the ultimate liabilities in the future with respect to these lawsuits and claims, in the aggregate, may be materially adverse to our cash flows, results of operations or financial condition.

19. Quarterly Information (Unaudited)

The table below details our quarterly financial information for the previous two fiscal years.

	Three Months Ended			
	March 31, 2009 (1)	June 30, 2009	September 30, 2009 (2)	December 31, 2009 (3)
	(In Thousands, Except Per Share Amounts)			
Total revenue	$ 768,088	$ 697,627	$ 641,560	$ 583,884
Income before interest and taxes	72,750	48,705	45,783	59,738
Income before taxes	56,391	26,059	20,880	33,935
Net income	43,426	20,192	16,458	24,357
Net income per share:				
Basic	$ 0.51	$ 0.24	$ 0.19	$ 0.29
Diluted	$ 0.51	$ 0.24	$ 0.19	$ 0.28

	Three Months Ended			
	March 31, 2008 (4)	June 30, 2008 (5)	September 30, 2008 (6)	December 31, 2008 (7)
			As Adjusted	As Adjusted
	(In Thousands, Except Per Share Amounts)			
Total revenue	$ 644,625	$ 826,838	$ 763,296	$ 755,030
Income (loss) before interest and taxes	68,975	(108,574)	93,490	74,863
Income (loss) before taxes	53,239	(125,794)	61,852	59,630
Net income (loss)	41,934	(93,338)	51,558	47,675
Net income (loss) per share				
Basic	$ 0.53	$ (1.16)	$ 0.62	$ 0.56
Diluted	$ 0.52	$ (1.16)	$ 0.61	$ 0.56

(1) Net income for the first quarter of 2009 included the recognition of $12.2 million in pre-tax income ($5.1 million benefit recorded in Cost of purchased coal revenue and $7.1 million in interest income) from the receipt of black lung excise tax refunds as authorized by federal legislation passed in October 2008. Additionally, during the first quarter of 2009, we sold our interest in certain coal reserves to a third party, recognizing a pre-tax gain of $7.1 million in Other revenue.

(2) Income for the third quarter of 2009 includes a $24.9 million pre-tax gain on the exchange of coal reserves.

(3) The results for the fourth quarter of 2009 included the impact of a $6.0 million reserve for bad debt related to a note receivable from a supplier.

(4) Income for the first quarter of 2008 includes a $13.6 million pre-tax gain on the exchange of coal reserves.

(5) Loss for the second quarter of 2008 includes $245.3 million pre-tax expense related to litigation with Wheeling-Pittsburgh Steel Corporation and a $15.3 million pre tax gain on the exchange of coal reserves.

(6) Income for the third quarter of 2008 includes $5.8 million pre-tax expense related to litigation with Wheeling-Pittsburgh Steel Corporation, $9.1 million pre-tax loss on financing transaction related to fees incurred for the tender offer for our 6.625% Notes (see Note 6 for further information), $3.6 million pre-tax gain on the exchange of coal reserves and other assets, and a $6.5 million pre-tax loss on short-term investment reflecting an impairment of our investment in the Primary Fund (see Note 16 for further information).

(7) Income for the fourth quarter of 2008 includes $12.9 million pre-tax income related to federal legislation passed that authorized refunds of black lung excise taxes paid in years that had been statutorily closed and $4.1 million pre-tax gain on financing transaction from the purchase of $19.0 million of our 3.25% Notes on the open market (see Note 6 for further information.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

There have been no changes in, or disagreements with, accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures and Changes in Internal Control Over Financial Reporting

We have established disclosure controls and procedures to ensure that information relating to us, including our consolidated subsidiaries, required to be disclosed in the reports that we file or submit under the Exchange Act, is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act), as of the end of the period covered by this report.

Based on our evaluation as of December 31, 2009, the principal executive officer and principal financial officer have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that the information required to be disclosed in reports that we file or furnish under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2009, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management is required to include in this Form 10-K an internal control over financial reporting report wherein management states its responsibility for establishing and maintaining adequate internal control structure and procedures for financial reporting and assesses the effectiveness of such structure and procedures. This management report follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Massey Energy Company ("Massey") is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Massey's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Massey's internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Massey; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of Massey; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Massey's assets that could have a material effect on the Company's financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Massey's management assessed the effectiveness of Massey's internal control over financial reporting as of December 31, 2009. In making this assessment, Massey used the criteria in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment based on those criteria, Massey's management has concluded that, as of December 31, 2009, internal control over financial reporting is effective.

The effectiveness of our internal control over financial reporting as of December 31, 2009, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which follows immediately hereafter.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Massey Energy Company

We have audited Massey Energy Company's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Massey Energy Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Massey Energy Company maintained, in all material respects, effective internal control over financial reporting as of December, 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2009 consolidated financial statements of Massey Energy Company and our report dated March 1, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Richmond, Virginia
March 1, 2010

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant

Don L. Blankenship, Age 59

Mr. Blankenship has been a director since 1996. He has been Chairman and Chief Executive Officer since November 2000 and also held the position of President from November 2000 until November 2008. He has been Chairman and Chief Executive Officer of A.T. Massey Coal Company, Inc., our wholly owned and sole, direct operating subsidiary, since 1992 and served as its President from 1992 until November 2008. Mr. Blankenship was formerly President and Chief Operating Officer from 1990 to 1991 and President of our subsidiary, Massey Coal Services, Inc., from 1989 to 1991. He joined our subsidiary, Rawl Sales & Processing Co., in 1982. He is a director of the National Mining Association and the United States Chamber of Commerce.

Baxter F. Phillips, Jr., Age 63

Mr. Phillips has been a director since 2007. He has been President since November 2008. Mr. Phillips previously served as Executive Vice President and Chief Administrative Officer from November 2004 to November 2008, as Senior Vice President and Chief Financial Officer from September 2003 to November 2004 and as Vice President and Treasurer from 2000 to August 2003. Mr. Phillips joined us in 1981 and has also served in the roles of Corporate Treasurer, Manager of Export Sales and Corporate Human Resources Manager, among others.

J. Christopher Adkins, Age 46

Mr. Adkins has been Senior Vice President and Chief Operating Officer since July 2003. Mr. Adkins joined our subsidiary, Rawl Sales & Processing Co., in 1985 to work in underground mining. Since that time, he has served as section foreman, plant supervisor, President and Vice President of several subsidiaries, President of our Eagle Energy subsidiary, Director of Production of Massey Coal Services, Inc. and Vice President of Underground Production.

Mark A. Clemens, Age 43

Mr. Clemens has been Senior Vice President, Group Operations since July 2007. From January 2003 to July 2007, Mr. Clemens was President of Massey Coal Services, Inc. Mr. Clemens was formerly President of Independence Coal Company, Inc., one of our operating subsidiaries, from 2000 through December 2002 and our Corporate Controller from 1997 to 1999. Mr. Clemens has held a number of other accounting positions and has been with us since 1989.

Michael K. Snelling, Age 53

Mr. Snelling has been Vice President, Surface Operations of our subsidiary, Massey Coal Services, Inc. since June 2005. Mr. Snelling was formerly Director of Surface Mining of Massey Coal Services, Inc. from July 2003 until May 2005. Mr. Snelling joined us in 2000 and has served us in a variety of capacities, including President of our subsidiary, Nicholas Energy Co. Prior to joining us, Mr. Snelling held various positions in the coal industry including engineer, production supervisor, plant supervisor, general foreman, manager of contract mining, superintendent, mine manager and vice president of operations.

Michael D. Bauersachs, Age 45

Mr. Bauersachs has been Vice President, Planning since May 2005. Mr. Bauersachs joined us in 1998, and served as Director of Acquisitions from 1998 until 2005. Prior to joining us, Mr. Bauersachs held various positions with Zeigler Coal Holding Company and Arch Mineral Corporation.

Jeffrey M. Gillenwater, Age 45

Mr. Gillenwater has been Vice President, Human Resources since January 2009. In October 1999, Mr. Gillenwater became Director of Human Resources at our Massey Coal Services, Inc. subsidiary, and held the position of Director of External Affairs & Administration from October 2002 until January 2009. Prior to October 2002 he held the position of Human Resources Manager at several of our subsidiaries.

Richard R. Grinnan, Age 41

Mr. Grinnan has been Vice President and Corporate Secretary since May 2006. He served as Senior Corporate Counsel from July 2004 until May 2006. Prior to joining us, Mr. Grinnan was a corporate and securities attorney at the law firm of McGuireWoods LLP in Richmond, Virginia from August 2000 until July 2004.

M. Shane Harvey, Age 40

Mr. Harvey has been Vice President and General Counsel since January 2008. He served as Vice President and Assistant General Counsel from November 2006 until January 2008 and as Corporate Counsel and Senior Corporate Counsel from April 2000 until November 2006. Prior to joining us, Mr. Harvey was an attorney at the law firm of Jackson Kelly PLLC in Charleston, West Virginia from May 1994 until April 2000.

Jeffrey M. Jarosinski, Age 50

Mr. Jarosinski was appointed Vice President, Treasurer and Chief Compliance Officer in February 2009. Prior to that he served as Vice President, Finance since 1998 and Chief Compliance Officer since December 2002. From 1998 through December 2002, Mr. Jarosinski was Chief Financial Officer. Mr. Jarosinski was formerly Vice President, Taxation from 1997 to 1998 and Assistant Vice President, Taxation from 1993 to 1997. Mr. Jarosinski joined us in 1988.

John M. Poma, Age 45

Mr. Poma has been Vice President and Chief Administrative Officer since January 2009. Mr. Poma previously served as Vice President, Human Resources from April 2003 to January 2009. Mr. Poma served as Corporate Counsel from 1996 until 2000 and as Senior Corporate Counsel from 2000 through March 2003. Prior to joining us in 1996, Mr. Poma was an employment attorney with the law firms of Midkiff & Hiner in Richmond, Virginia and Jenkins, Fenstermaker, Krieger, Kayes & Farrell in Huntington, West Virginia.

Steve E. Sears, Age 61

Mr. Sears has been Vice President, Sales and Marketing, and President of our subsidiary Massey Coal Sales Company, Inc. since December 2008. Mr. Sears served as President of Massey Industrial and Utility Sales, a division of Massey Coal Sales Company, Inc., from December 2006 to December 2008. Mr. Sears has held various positions within the sales department. He joined us in 1981.

Eric B. Tolbert, Age 42

Mr. Tolbert has been Vice President and Chief Financial Officer since November 2004. Mr. Tolbert served as Corporate Controller from 1999 to 2004. He joined us in 1992 as a financial analyst and subsequently served as Director of Financial Reporting. Prior to joining us, Mr. Tolbert worked for the public accounting firm Arthur Andersen from 1990 to 1992.

David W. Owings, Age 36

Mr. Owings has been Corporate Controller and principal accounting officer since November 2004. Mr. Owings previously served as Manager of Financial Reporting since joining us in 2001. Prior to joining us, Mr. Owings worked at Ernst & Young LLP, the Company's independent registered public accounting firm, serving as a manager from January 2001 through September 2001 and as a senior auditor from October 1998 through January 2001 in the Assurance and Advisory Business Services group.

The following information is incorporated by reference from our definitive proxy statement pursuant to Regulation 14A, which will be filed not later than 120 days after the close of Massey's fiscal year ended December 31, 2009:

- Information regarding the directors required by this item is found under the heading *Election of Directors*.
- Information regarding our Audit Committee required by this item is found under the heading *Committees of the Board*.

- Information regarding Section 16(a) Beneficial Ownership Reporting Compliance required by this item is found under the heading *Section 16(a) Beneficial Ownership Reporting Compliance*.

- Information regarding our Code of Ethics required by this item is found under the heading *Code of Ethics*.

Because Common Stock is listed on the NYSE, our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of May 21, 2009. In addition, we have filed, as exhibits to this annual report on Form 10-K, the certifications of our principal executive officer and principal financial officer required under Section 302 of the Sarbanes Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

Item 11. Executive Compensation

Information required by this item is included in the *Compensation Discussion and Analysis, Compensation of Named Executive Officers, Compensation Committee Interlocks and Insider Participation, and Compensation Committee Report on Executive Compensation* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2009.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item is included in the *Stock Ownership of Directors and Executive Officers* and *Stock Ownership of Certain Beneficial Owners* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2009.

The following table sets forth as of December 31, 2009, the number of shares of Common Stock authorized for issuance under our equity compensation plan.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights (1), (2)	(b) Weighted-average per share exercise price of outstanding options, warrants and rights (2)	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders	2,053,082	$ 27.05	2,704,145
Equity compensation plans not approved by shareholders (3)	-	-	-
Total	2,053,082	$ 27.05	2,704,145

(1) There are no outstanding warrants or rights.
(2) These amounts do not include shares to be issued upon vesting of restricted stock because they have no exercise price.
(3) We do not have any equity compensation plans that have not been approved by our shareholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is included in the *Certain Relationships and Related Transactions* and *Director Independence* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2009.

Item 14. Principal Accountant Fees and Services

Information concerning principal accountant fees and services contained under the heading *The Audit Committee Report* in the definitive proxy statement pursuant to Regulation 14A, which is incorporated by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2009.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report:

1. Financial Reports:

Consolidated Statements of Income for the Fiscal Years Ended December 31, 2009, 2008 and 2007

Consolidated Balance Sheets at December 31, 2009 and 2008

Consolidated Statements of Cash Flows for the Fiscal Years Ended December 31, 2009, 2008, and 2007

Consolidated Statements of Shareholders' Equity for the Fiscal Years Ended December 31, 2009, 2008, and 2007

Notes to Consolidated Financial Statements

2. Financial Statement Schedules: Except as set forth below, all schedules have been omitted since the required information is not present or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the Consolidated Financial Statements and Notes thereto.

Schedule II—Valuation and Qualifying Accounts

3. Exhibits:

Exhibit No.	Description
3.1	Certificate of Ownership and Merger merging Massey Energy Company with and into Fluor Corporation accompanied by Restated Certificate of Incorporation of Massey Energy Company, as amended [filed as Exhibit 3.1 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
3.2	Restated Bylaws (as amended as of July 1, 2009) of Massey Energy Company [filed as Exhibit 3.1 to Massey's current report on Form 8-K filed July 2, 2009 and incorporated by reference]
4.1	Senior Indenture, dated May 29, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors and Wilmington Trust Company, as Trustee, [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed May 30, 2003 and incorporated by reference]
4.2	Second Supplemental Indenture, dated April 7, 2004, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, supplementing that certain Senior Indenture dated May 29, 2003, in connection with the Company's 2.25% Convertible Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed April 4, 2004 and incorporated by reference]
4.3	Third Supplemental Indenture, dated July 20, 2009, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 2.25% Senior Notes [filed as Exhibit 4.1 to Massey's quarterly report on Form 10-Q filed August 10, 2009 and incorporated by reference].
4.4	Fourth Supplemental Indenture, dated August 28, 2009, by and among Massey Energy Company, subsidiaries of Massey Energy Company as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 2.25% Senior Notes [filed as Exhibit 4.1 to Massey's quarterly report on Form 10-Q filed October 28, 2009 and incorporated by reference].
4.5	Indenture, dated as of December 21, 2005, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.875% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed December 21, 2005, and incorporated by reference]
4.6	First Supplemental Indenture, dated July 20, 2009, by and among Massey Energy Company, subsidiaries of Massey Energy Company as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.875% Senior Notes [filed as Exhibit 4.3 to Massey's quarterly report on Form 10-Q filed August 10, 2009 and incorporated by reference].

4.7	Second Supplemental Indenture, dated August 28, 2009, by and among Massey Energy Company, subsidiaries of Massey Energy Company as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.875% Senior Notes [filed as Exhibit 4.3 to Massey's quarterly report on Form 10-Q filed October 28, 2009 and incorporated by reference].
4.8	Senior Indenture, dated as of August 12, 2008, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 3.25% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed August 12, 2008, and incorporated by reference]
4.9	First Supplemental Indenture, dated as of August 12, 2008, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 3.25% Senior Notes [filed as Exhibit 4.2 to Massey's current report on Form 8–K filed August 12, 2008, and incorporated by reference]
4.10	Second Supplemental Indenture, dated as of July 20, 2009, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 3.25% Senior Notes [filed as Exhibit 4.4 to Massey's quarterly report on Form 10-Q filed August 10, 2009, and incorporated by reference]
4.11	Third Supplemental Indenture, dated as of August 28, 2009, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 3.25% Senior Notes [filed as Exhibit 4.4 to Massey's quarterly report on Form 10-Q filed October 28, 2009, and incorporated by reference]
10.1	Amended and Restated Credit Agreement dated as of August 15, 2006, among A. T. Massey Coal Company, Inc. and certain of its subsidiaries, as Borrowers, Massey Energy Company and certain of its subsidiaries, as Guarantors, Bank of America, N. A., as Syndication Agent, General Electric Capital Corporation, as Documentation Agent, The CIT Group/Business Credit, Inc., as Collateral Agent, UBS Securities LLC, as Arranger, UBS AG, Stamford Branch, as Administrative Agent, and UBS Loan Finance LLC, as Swingline Lender, and the lenders party thereto [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.2	First Amendment to Amended and Restated Credit Agreement dated March 12, 2007 [filed as Exhibit 10.1 to Massey's quarterly report on Form 10-Q filed May 10, 2007 and incorporated by reference]
10.3	Limited Consent and Second Amendment to Amended and Restated Credit Agreement dated July 19, 2007 [filed as Exhibit 10.1 to Massey's quarterly report on Form 10-Q filed August 9, 2007 and incorporated by reference]
10.4	Third Amendment to Amended and Restated Credit Agreement dated March 10, 2008 [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed March 14, 2008 and incorporated by reference]
10.5	Fourth Amendment to Amended and Restated Credit Agreement dated October 10, 2008 [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed October 16, 2008 and incorporated by reference]
10.6	Equity Distribution Agreement dated February 3, 2009 between Massey Energy Company and UBS Securities LLC [filed as Exhibit 1.1 to Massey's current report on Form 8-K filed February 4, 2009 and incorporated by reference]
10.7	Massey Energy Company 1982 Shadow Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.8 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.8	Massey Energy Company 1988 Executive Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.6 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.9	Massey Energy Company 1996 Executive Stock Plan (as amended and restated, effective January 1, 2009) [filed as Exhibit 10.14 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.10	Massey Energy Company 1997 Stock Appreciation Rights Plan (as amended and restated, effective November 30, 2000) [filed as Exhibit 10.9 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.11	Massey Energy Company 1999 Executive Performance Incentive Plan (as amended and restated, effective January 1, 2009) [filed as Exhibit 10.15 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.12	Massey Energy Company 2006 Stock and Incentive Compensation Plan (as amended and restated, effective August 18, 2009) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed August 21, 2009 and incorporated by reference]

10.13	Form of Non-Employee Director Initial Restricted Stock Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed December 31, 2008 and incorporated by reference]
10.14	Form of Non-Employee Director Initial Restricted Unit Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed December 31, 2008 and incorporated by reference]
10.15	Form of Non-Employee Director Annual Restricted Stock Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed February 22. 2010 and incorporated by reference]
10.16	Form of Non-Employee Director Annual Stock Option Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed February 22, 2010 and incorporated by reference]
10.17	Form of stock option agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed November 16, 2009 and incorporated by reference]
10.18	Form of restricted stock agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed November 16, 2009 and incorporated by reference]
10.19	Form of restricted unit agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.4 to Massey's current report on Form 8-K filed November 16, 2009 and incorporated by reference]
10.20	Form of cash incentive award agreement based on earnings before taxes under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
10.21	Form of amended cash incentive award agreement based on earnings before taxes under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.2 to Massey's current report in Form 8-K filed January 6, 2010 and incorporated by reference.
10.22	Form of cash incentive award agreement based on earnings before interest and taxes under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
10.23	Form of cash incentive award agreement based on earnings before interest, taxes, deprecation and amortization under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.7 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
10.24	A.T. Massey Coal Company, Inc. Supplemental Benefit Plan (as amended and restated as of January 1, 2009) [filed as Exhibit 10.20 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.25	A.T. Massey Coal Company, Inc. Executive Deferred Compensation Plan (as amended and restated as of January 1, 2009) [filed as Exhibit 10.19 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.26	Massey Executive Deferred Compensation Program (as amended and restated as of January 1, 2009) [filed as Exhibit 10.17 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.27	Massey Energy Company Executive Physical Program [filed as Exhibit 10.3 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.28	Massey Executives' Supplemental Benefit Plan (as amended and restated effective January 1, 2009) [filed as Exhibit 10.13 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.29	Massey Executives' Supplemental Benefit Plan Agreement (effective as of January 1, 2005) between Massey and Don L. Blankenship [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed January 5, 2006 and incorporated by reference]
10.30	Letter Agreement dated December 30, 2009, between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed January 6, 2010 and incorporated by reference]
10.31	Retention and Employment Agreement as amended and restated, effective January 1, 2009, between Massey Energy Company and John Christopher Adkins [filed as Exhibit 10.10 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]

10.32	Amendment to Retention and Employment Agreement between Massey Energy Company and John C. Adkins effective January 1, 2010 [filed as Exhibit 10.4 to Massey's current report of Form 8-K filed January 6, 2010 and incorporated by reference]
10.33	Employment Agreement dated May 28, 2009 between Massey Energy Company and Michael K. Snelling [filed as Exhibit 10.1 to Massey's quarterly report on Form 10-Q filed August 10, 2009 and incorporated by reference]
10.34	Special Successor and Development Retention Program between Fluor Corporation and Don L. Blankenship dated as of September 1998 [filed as Exhibit 10.21 to Fluor's annual report on Form 10-K for the fiscal year ended October 31, 1998 and incorporated by reference]
10.35	Amendment to Special Successor and Development Retention Program between Massey (formerly Fluor Corporation) and Don L. Blankenship, effective January 1, 2009 [filed as Exhibit 10.23 to Massey's current report on Form 8-K filed December 24, 2008]
10.36	Employment and Change in Control Agreement dated November 10, 2008 between Massey Energy Company and Baxter F. Phillips, Jr. [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
10.37	Amendment to Employment and Change in Control Agreement between Massey Energy Company and Baxter F. Phillips, Jr. effective January 1, 2010 [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed January 6, 2010 and incorporated by reference]
10.38	Form of Change in Control Severance Agreement for Tier 1 Participants [filed as Exhibit 10.36 to Massey's annual report on Form 10-K filed March 2, 2009 and incorporated by reference]
10.39	Form of Change in Control Severance Agreement for Tier 2 Participants [filed Exhibit 10.37 to Massey's annual report on Form 10-K filed March 2, 2009 and incorporated by reference]
10.40	Form of Change in Control Severance Agreement for Tier 3 Participants [filed Exhibit 10.38 to Massey's annual report on Form 10-K filed March 2, 2009 and incorporated by reference]
10.41	Change in Control Severance Agreement (as amended and restated) dated as of December 23, 2008 between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.24 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.42	Change in Control Severance Agreement (as amended and restated) dated as of December 23, 2008 between Massey Energy Company and J. Christopher Adkins [filed as Exhibit 10.25 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.43	Change in Control Severance Agreement (as amended and restated) dated as of December 23, 2008 between Massey Energy Company and Eric B. Tolbert [filed as Exhibit 10.26 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.44	Change in Control Severance Agreement (as amended and restated) dated as of December 23, 2008 between Massey Energy Company and Michael K. Snelling [filed as Exhibit 10.27 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.45	Massey Energy Company 2010 - 2012 Long Term Incentive Award Program as reported on Massey's current report on Form 8-K [filed November 16, 2009 and incorporated by reference]
10.46	Massey Energy Company 2010 Bonus Program as reported on Massey's current report on Form 8-K [filed November 16, 2009 and incorporated by reference]
10.47	Base salary amounts set for Massey's named executive officers as reported on Massey's current reports on Form 8-K [filed November 16, 2009 and January 6, 2010 and incorporated by reference]
10.48	Massey Energy Company Non-Employee Directors Compensation Summary (as amended and restated effective November 9, 2009) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed November 16, 2009 and incorporated by reference]
10.49	Massey Energy Company Stock Plan for Non-Employee Directors (as amended and restated, effective January 1, 2009) [filed as Exhibit 10.21 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.50	Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors (as amended and restated, effective January 1, 2009) [filed as Exhibit 10.22 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.51	Massey Energy Company Deferred Directors' Fees Program (amended and restated, effective January 1, 2009) [filed as Exhibit 10.18 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]

10.52	Distribution Agreement between Fluor Corporation and Massey Energy Company dated as of November 30, 2000 [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed December 15, 2000 and incorporated by this reference]
10.53	Tax Sharing Agreement between Fluor Corporation, Massey Energy Company and A.T. Massey Coal Company, Inc. dated as of November 30, 2000 [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed December 15, 2000 and incorporated by this reference]
21	Massey Energy Company Subsidiaries [filed herewith]
23.1	Consent of Independent Registered Public Accounting Firm [filed herewith]
24	Manually signed Powers of Attorney executed by Massey directors [filed herewith]
31.1	Certification of Chief Executive Officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 [filed herewith]
31.2	Certification of Chief Financial Officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 [filed herewith]
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 [furnished herewith]
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 [furnished herewith]
101	Interactive Data File (Annual Report on Form 10-K, for the fiscal year ended December 31, 2009, furnished in XBRL (eXtensible Business Reporting Language)).
	Attached as Exhibit 101 to this report are the following documents formatted in XBRL: (i) the Consolidated Statements of Income for each of the years ended December 31, 2009, 2008 and 2007, (ii) the Consolidated Balance Sheets at December 31, 2009 and 2008, (iii) the Consolidated Statement of Cash Flows for each of the years ended December 31, 2009, 2008 and 2007, (iv) the Consolidated Statement of Shareholders' Equity for each of the years ended December 31, 2009, 2008 and 2007, (v) the Notes to the Consolidated Financial Statements, tagged as blocks of text and (vi) Schedule II - Valuation of Qualifying Accounts, tagged as blocks of text. Users of this data are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposed of section 18 of the Securities and Exchange Act of 1934, and otherwise is not subject to liability under these sections.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

March 1, 2010

MASSEY ENERGY COMPANY

By: /s/ ERIC B. TOLBERT
Eric B. Tolbert,
Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
Principal Executive Officer and Director:		
/s/ DON L. BLANKENSHIP **Don L. Blankenship**	Chairman and Chief Executive Officer	March 1, 2010
Principal Financial Officer:		
/s/ ERIC B. TOLBERT **Eric B. Tolbert**	Vice President and Chief Financial Officer	March 1, 2010
Principal Accounting Officer:		
/s/ DAVID W. OWINGS **David W. Owings**	Controller	March 1, 2010
Other Directors:		
* **James B. Crawford**	Director	March 1, 2010
* **Robert H. Foglesong**	Director	March 1, 2010
* **Richard M. Gabrys**	Director	March 1, 2010
* **Bobby R. Inman**	Director	March 1, 2010
* **Lady Judge**	Director	March 1, 2010
* **Dan R. Moore**	Director	March 1, 2010
* **Baxter F. Phillips, Jr.**	Director and President	March 1, 2010
* **Stanley C. Subuleski**	Director	March 1, 2010

By: /s/ Richard R. Grinnan March 1, 2010
Richard R. Grinnan
Attorney-in-fact

* Manually signed Powers of Attorney authorizing Eric B. Tolbert, Richard R. Grinnan, M. Shane Harvey, and Jeffrey M. Jarosinski, and each of them, to sign the annual report on Form 10-K for the fiscal year ended December 31, 2009 and any amendments thereto as attorneys-in-fact for certain directors and officers of the registrant are included herein as Exhibits 24.

MASSEY ENERGY COMPANY

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS
(In Thousands)

Description	Balance at Beginning of Period	Amounts Charged to Costs and Expenses	Deductions [1]	Other	Balance at End of Period
YEAR ENDED DECEMBER 31, 2009					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 873	$ 6,430 [2]	$ -	$ -	$ 7,303
YEAR ENDED DECEMBER 31, 2008					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 444	$ 429	$ -	$ -	$ 873
YEAR ENDED DECEMBER 31, 2007					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 576	$ (132)	$ -	$ -	$ 444

(1) Reserves utilized, unless otherwise indicated.

(2) Allowance for accounts and notes receivable for the year ended December 31, 2009 includes a $6 million reserve for bad debt related to a note receivable from a supplier, which was recorded in Other noncurrent assets at December 31, 2009.