International Coal Group, Inc.
Form 10-K
February 27, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-K

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

For the fiscal year ended December 31, 2008

OR

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

Commission file number: 001-32679

International Coal Group, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	20-2641185
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

300 Corporate Centre Drive
Scott Depot, WV 25560
(Address of Principal Executive Offices—Zip Code)

(304) 760-2400
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:	Name on each exchange on which registered:
Common Stock, par value $0.01 per share	The New York Stock Exchange

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. Yes x No ¨

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 definition of "accelerated filer," "large accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one).

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

Aggregate market value of common stock held by non-affiliates of the registrant as of June 30, 2008, the last business day of the registrant's most recently completed second fiscal quarter, at a closing price of $13.05 per share as reported by the New York Stock Exchange, was $1,392,427,588. Shares of common stock beneficially held by each executive officer and director and their respective spouses have been excluded since such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

Number of shares of common stock outstanding as of February 19, 2009 was 153,335,680.

DOCUMENTS INCORPORATED BY REFERENCE

Part III incorporates certain information by reference from the registrant's definitive proxy statement for the 2009 annual meeting of stockholders, which proxy statement will be filed on or about April 15, 2009.

INDEX TO ANNUAL REPORT
ON FORM 10-K

Table of Contents

Item 1.	BUSINESS	1
Item 1A.	RISK FACTORS	29
Item 1B.	UNRESOLVED STAFF COMMENTS	48
Item 2.	PROPERTIES	49
Item 3.	LEGAL PROCEEDINGS	55
Item 4.	SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS	56
Item 5.	MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES	57
Item 6.	SELECTED FINANCIAL DATA	58
Item 7.	MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	61
Item 7A.	QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	84
Item 8.	FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA	84
Item 9.	CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE	85
Item 9A.	CONTROLS AND PROCEDURES	85
Item 9B.	OTHER INFORMATION	85
Item 10.*	DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE	86
Item 11.*	EXECUTIVE COMPENSATION	86
Item 12.*	SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS	86
Item 13.*	CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE	86
Item 14.*	PRINCIPAL ACCOUNTANT FEES AND SERVICE	86
Item 15.	EXHIBITS, FINANCIAL STATEMENT SCHEDULES	87

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* The information required by Items 10, 11, 12, 13 and 14, to the extent not included in this document, is incorporated herein by reference to the information included under the captions "Election of Directors," "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," "Certain Relationships and Related Party Transactions," "Audit Matters," and " Executive Officers" in the registrant's definitive proxy statement which is expected to be filed on or about April 15, 2009.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that are not statements of historical fact and may involve a number of risks and uncertainties. We have used the words “anticipate,” “believe,” “could,” “estimate,” “expect,” “intend,” “may,” “plan,” “predict,” “project” and similar terms and phrases, including references to assumptions, in this report to identify forward-looking statements. These forward-looking statements are made based on expectations and beliefs concerning future events affecting us and are subject to uncertainties and factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control, that could cause our actual results to differ materially from those matters expressed in or implied by these forward-looking statements. The following factors are among those that may cause actual results to differ materially from our forward-looking statements:

- market demand for coal, electricity and steel;
- availability of qualified workers;
- future economic or capital market conditions;
- weather conditions or catastrophic weather-related damage;
- our production capabilities;
- consummation of financing, acquisition or disposition transactions and the effect thereof on our business;
- a significant number of conversions of our Convertible Senior Notes prior to maturity;
- our plans and objectives for future operations and expansion or consolidation;
- our relationships with, and other conditions affecting, our customers;
- availability and costs of key supplies or commodities such as diesel fuel, steel, explosives and tires;
- availability and costs of capital equipment;
- prices of fuels which compete with or impact coal usage, such as oil and natural gas;
- timing of reductions or increases in customer coal inventories;
- long-term coal supply arrangements;
- risks in or related to coal mining operations, including risks relating to third-party suppliers and carriers operating at our mines or complexes;
- unexpected maintenance and equipment failure;

- environmental, safety and other laws and regulations, including those directly affecting our coal mining and production, and those affecting our customers' coal usage;
- ability to obtain and maintain all necessary governmental permits and authorizations;
- competition among coal and other energy producers in the United States and internationally;
- railroad, barge, trucking and other transportation availability, performance and costs;
- employee benefits costs and labor relations issues;
- replacement of our reserves;
- our assumptions concerning economically recoverable coal reserve estimates;
- availability and costs of credit, surety bonds and letters of credit;
- title defects or loss of leasehold interests in our properties which could result in unanticipated costs or inability to mine these properties;
- future legislation and changes in regulations or governmental policies or changes in interpretations or enforcement thereof, including with respect to safety enhancements and environmental initiatives relating to global warming;
- impairment of the value of our long-lived and deferred tax assets;
- our liquidity, including the ability to adhere to financial covenants related to our borrowing arrangements, results of operations and financial condition;
- adequacy and sufficiency of our internal controls; and
- legal and administrative proceedings, settlements, investigations and claims and the availability of related insurance coverage.

You should keep in mind that any forward-looking statement made by us in this Annual Report on Form 10-K speaks only as of the date on which we make it. New risks and uncertainties arise from time to time, and it is impossible for us to predict these events or how they may affect us. We have no duty to, and do not intend to, update or revise the forward-looking statements in this report after the date of this report, except as may be required by law. In light of these risks and uncertainties, you should keep in mind that any forward-looking statement made in this report might not occur.

Table of Contents

PART I

Introduction

This report is both our 2008 annual report to stockholders and our 2008 Annual Report on Form 10-K required under the federal securities laws.

In this annual report, the term “Horizon” refers to Horizon NR, LLC (the entity holding the operating subsidiaries of Horizon Natural Resources Company) and its consolidated subsidiaries, the term “Anker” refers to Anker Coal Group, Inc. and its consolidated subsidiaries, and the term “CoalQuest” refers to CoalQuest Development, LLC. References to the “Anker and CoalQuest acquisitions” refer to our acquisition, respectively, of each of Anker and CoalQuest, which occurred on November 18, 2005. Unless otherwise noted, all of our actual production and financial information includes the results of Anker and CoalQuest since November 19, 2005. On November 18, 2005, we and our subsidiaries also underwent a corporate reorganization in which we became the parent holding company and ICG, Inc., the prior parent holding company, became our subsidiary. Unless the context otherwise indicates, as used in this annual report, the terms “ICG,” “we,” “our,” “us” and similar terms refer to International Coal Group, Inc. and its consolidated subsidiaries, after giving effect to the corporate reorganization and the Anker and CoalQuest acquisitions.

For purposes of all financial disclosures contained in this report, Horizon (together with its predecessor AEI Resources Holding, Inc. and its consolidated subsidiaries) is the predecessor to ICG.

The term “coal reserves” as used in this report means proven and probable reserves that are the part of a mineral deposit that can be economically and legally extracted or produced at the time of the reserve determination and the term “non-reserve coal deposits” in this report means a coal bearing body that has been sufficiently sampled and analyzed to assume continuity between sample points, but do not qualify as a commercially viable coal reserve as prescribed by SEC rules until a final comprehensive SEC prescribed evaluation is performed.

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

ITEM 1. BUSINESS

Overview

We are a leading producer of coal in Northern and Central Appalachia with a broad range of mid to high Btu, low to medium sulfur steam and metallurgical coal. Our Appalachian mining complexes, which include 12 of our mining complexes, are located in West Virginia, Kentucky, Virginia and Maryland. We also have a complementary mining complex of mid to high sulfur steam coal strategically located in the Illinois Basin. We market our coal to a diverse customer base of largely investment grade electric utilities, as well as domestic and international industrial customers. The high quality of our coal and the availability of multiple transportation options, including rail, truck and barge, throughout the Appalachian region enable us to participate in both the domestic and international coal markets. Appalachian coal markets exhibited price volatility in 2008 that has continued into 2009.

ICG, Inc. was formed by WL Ross & Co. LLC (“WLR”), and other investors, in May 2004 to acquire and operate competitive coal mining facilities. As of September 30, 2004, ICG, Inc. acquired certain key assets of Horizon through a bankruptcy auction. These assets are high quality reserves strategically located in Appalachia and the Illinois Basin and are union free. Due to its initial capitalization, ICG, Inc. was able to complete the acquisition without incurring a significant level of indebtedness. Consistent with the WLR investor group’s strategy to consolidate

attractive coal assets, we completed a corporate reorganization (described below) and acquired Anker and CoalQuest in November 2005, which further diversified our coal reserves.

Table of Contents

As of December 31, 2008, management estimates that we owned or controlled approximately 328 million tons of metallurgical quality coal reserves and approximately 689 million tons of steam coal reserves. Management's estimates were developed considering an initial evaluation, as well as subsequent acquisitions, dispositions, depleted reserves, changes in available geological or mining data and other factors. Further, we own or control approximately 521 million tons of non-reserve coal deposits.

Steam coal is primarily consumed by large electric utilities and industrial customers as fuel for electricity generation. Demand for low sulfur steam coal has grown significantly since the introduction of certain controls associated with the Clean Air Act and the decline in coal production in the eastern half of the United States. Metallurgical coal is primarily used to produce coke, a key raw material used in the steel making process. Generally, metallurgical coal sells at a premium to steam coal because of its higher quality and its importance and value in the steel making process.

For the year ended December 31, 2008, we sold 18.9 million tons of coal, of which approximately 17.9 million tons were produced from our mining activities and approximately 1.0 million tons were purchased through brokered coal contracts (coal purchased from third parties for resale), at an average sale price of $53.22 and $45.10, respectively. Of the tons sold, 17.8 million tons were steam coal and 1.1 million tons were metallurgical coal. Our steam coal sales volume in 2008 consisted of mid to high quality, high Btu (greater than 12,000 Btu/lb.), low to medium sulfur (1.5% or less) coal, which typically sells at a premium to lower quality, lower Btu, higher sulfur steam coal. Our three largest customers for the year ended December 31, 2008 were Progress Energy, Georgia Power Company and Allegheny Energy Supply Company and we derived approximately 32% of our coal revenues from sales to our five largest customers. We did not derive more than 10% of our coal sales revenues from any single customer in 2008.

We have three reportable business segments, which are based on the coal regions in which we operate: (i) Central Appalachian, comprised of both surface and underground mines, (ii) Northern Appalachian, comprised of both surface and underground mines and (iii) Illinois Basin, representing one underground mine. Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States of America, as of and for the years ended December 31, 2008, 2007 and 2006 is included in Note 20 to our consolidated financial statements included elsewhere in this report.

History

The Horizon Acquisition

On February 28, 2002, Horizon (at that time operating as AEI Resources Holdings, Inc.) filed a voluntary petition for Chapter 11 and its plan of reorganization became effective on May 8, 2002. However, Horizon's profit margins and cash flows were negatively impacted in fiscal year 2002 by, among other things, the falling price of coal and continued increases in certain operating expenses. Due to capital and permit constraints, Horizon had to mine in areas which produced coal at greatly reduced profit margins thus severely reducing cash flow.

As a result of its continuing financial and operational difficulties, Horizon filed a second voluntary petition for relief under Chapter 11 on November 13, 2002. Horizon obtained a debtor-in-possession financing facility of up to $350.0 million and was effective in rationalizing its operations, selling non-core assets, paying down outstanding borrowings and generating substantial operating profit. With stabilized operations and a significantly improved coal market, Horizon filed a joint plan of reorganization and a joint plan of liquidation under Chapter 11.

ICG, Inc. was formed by WLR and other investors in May 2004. The Horizon assets were sold through a bankruptcy auction on August 17, 2004. Presented as a combined $290.0 million cash bid with A.T. Massey, ICG, Inc. agreed to pay $285.0 million in cash plus the assumption of up to $5.0 million of liabilities to be paid to contract counterparties

to cure the pre-sale defaults under the leases and contracts assumed and assigned to ICG, Inc. to acquire the assets. ICG, Inc. also contributed a credit bid of second lien Horizon bonds, and A.T. Massey agreed to pay $5.0 million in cash to acquire a separate group of assets associated with two Horizon subsidiaries. The credit bid included the cancellation of $482.0 million of certain Horizon bonds in return for which those Horizon bondholders received the right to participate in a rights offering to purchase ICG common stock. Shares issued in connection with the rights offering are included in our outstanding stock.

Table of Contents

In addition, Lexington Coal Company, LLC, a newly formed entity, was organized by the founding ICG, Inc. stockholders to assume certain reclamation liabilities and assets not otherwise being purchased by A.T. Massey or ICG, Inc. In order to provide support to Lexington Coal Company in consideration for assuming these liabilities, we agreed, among other things, to pay a 0.75% additional payment on the gross sales receipts for coal mined and sold from the assets we acquired from Horizon until the completion by Lexington Coal Company of all reclamation liabilities acquired from Horizon. Other than the initial limited commonality of ownership of ICG and Lexington Coal Company, there is no relationship between the entities.

The bankruptcy court confirmed the sale on September 16, 2004 as part of the completion of the Horizon bankruptcy proceedings. At closing, we increased the purchase price by $6.25 million, primarily to satisfy increased administrative expenses, and the sale was completed as of September 30, 2004.

The acquisition was financed through equity investments and borrowings under our senior secured credit facility, which we entered into at the closing of the Horizon acquisition.

The Anker and CoalQuest Acquisitions

On March 31, 2005, ICG, Inc. entered into a business combination agreement with us, Anker and ICG Merger Sub, Inc., our indirect wholly owned subsidiary, and Anker Merger Sub, Inc., our indirect wholly owned subsidiary. Under the terms of the business combination agreement, on November 18, 2005, ICG Merger Sub merged with and into ICG, Inc. and Anker Merger Sub merged with and into Anker, with each of ICG, Inc. and Anker surviving their respective mergers as our wholly owned subsidiaries and we became the new parent holding company. The stockholders of Anker, collectively, received 14,840,909 shares of our common stock.

On March 31, 2005, ICG, Inc. also entered into a business combination agreement with us, CoalQuest and CoalQuest Merger Sub LLC, our indirect wholly owned subsidiary, and the members of CoalQuest. Under the terms of the business combination agreement, on November 18, 2005, the members of CoalQuest contributed their interests in CoalQuest to us in exchange for shares of our common stock. As a result of this contribution, CoalQuest became our wholly owned subsidiary. The members of CoalQuest, collectively, received 9,250,000 shares of our common stock.

Our Reorganization and Public Offering

On November 18, 2005, International Coal Group, Inc. also completed a corporate reorganization. Prior to this reorganization, the top-tier parent holding company was ICG, Inc. Upon completion of this reorganization, International Coal Group, Inc. became the new top-tier parent holding company. In the corporate reorganization, the stockholders of ICG, Inc. received one share of International Coal Group, Inc. common stock for each share of ICG, Inc. common stock. On November 21, 2005, International Coal Group, Inc. common stock commenced trading on the New York Stock Exchange.

On December 12, 2005, we completed a public offering of 21,000,000 shares of common stock. Net proceeds from the public offering were approximately $210.5 million. We used the proceeds to repay $188.7 million of our term loan debt and $21.2 million of borrowings under our revolving credit facility.

The Coal Industry

A major contributor to the world energy supply, coal represents over 26% of the world’s primary energy consumption according to the World Coal Institute. The primary use for coal is to fuel electric power generation. In 2008, coal-fired plants generated approximately 49% of the electricity produced in the United States, according to the Energy

Information Administration (“EIA”), a statistical agency of the U.S. Department of Energy.

Table of Contents

Coal Markets

Coal produced in the United States is used primarily by utilities to generate electricity, by steel companies to produce coke for use in blast furnaces and by a variety of industrial users to heat and 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 west coast terminals. Coal used as fuel to generate electricity is commonly referred to as "steam coal."

Coal has long been favored as an electricity generating fuel by regulated utilities because of its basic economic advantage. The largest cost component in electricity generation is fuel. According to the National Mining Association, coal is the most affordable source of power fuel per million Btu, averaging less than one-quarter the price of both petroleum and natural gas.

The other major market for coal is the steel industry. The type of coal used in steel making is referred to as metallurgical coal and is distinguished by special quality characteristics that include high carbon content, favorable coking characteristics and various other chemical attributes. Metallurgical coal is also generally higher in heat content (as measured in Btus), and therefore is also desirable to utilities as fuel for electricity generation. Consequently, metallurgical coal producers have the ongoing opportunity to select the market that provides maximum revenue and margins. 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.

Coal Mining Methods

We produce coal using two mining methods: underground room-and-pillar mining using continuous mining equipment and surface mining, which are explained as follows:

Underground mining

Underground mines in the United States are typically operated using one of two different techniques: room-and-pillar mining or longwall mining. In 2008, approximately 43% of our produced and processed coal volume came from underground mining operations using the room-and-pillar method with continuous mining equipment.

Room-and-Pillar Mining

In room-and-pillar mining, rooms are cut into the coalbed leaving a series of pillars, or columns of coal, to help support the mine roof and control the flow of air. Continuous mining equipment is used to cut the coal from the mining face. Generally, openings are driven 20 feet wide and the pillars are generally rectangular in shape measuring 35-50 feet wide by 35-80 feet long. As mining advances, a grid-like pattern of entries and pillars is formed. Shuttle cars are used to transport coal to the conveyor belt for transport to the surface. 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 cave. When retreat mining is completed to the mouth of the panel, the mined panel is abandoned. The room-and-pillar method is often used to mine smaller coal blocks or thinner seams. It is also employed whenever subsidence is prohibited. Seam recovery ranges from 35% to 70%, with higher seam recovery rates applicable where retreat mining is combined with room-and-pillar mining.

Longwall Mining

The other underground mining method commonly used in the United States is the longwall mining method. We do not currently have any longwall mining operations, but we expect to use this mining method in the development of our Hillman property in Taylor County, West Virginia. In longwall mining, a rotating drum is trammed mechanically across the face of coal and a hydraulic system supports the roof of the mine while it advances through the coal. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface.

Table of Contents

Surface mining

Surface mining is used when coal is found close to the surface. In 2008, approximately 57% of our produced and processed coal volume came from surface mines. This method involves the removal of overburden (earth and rock covering the coal) with heavy earth moving equipment and explosives, loading out the coal, replacing the overburden and topsoil after the coal has been excavated and reestablishing vegetation and plant life and frequently making other improvements that have local community and environmental benefit. Overburden is typically removed at our mines using large, rubber-tired diesel loaders. Seam recovery for surface mining is typically between 80% and 90%. Productivity depends on equipment, geological composition and mining ratios.

We use the following three types of surface mining methods.

Truck-and-Shovel/Loader Mining

Truck-and-shovel/loader mining is a surface mining method that uses large shovels or loaders to remove overburden which is used to backfill pits after coal removal. Shovels or loaders load coal into haul trucks for transportation to a preparation plant or unit train loadout facility. Seam recovery using the truck-and-shovel/loader mining method is typically 85% or more.

Dragline Mining

Dragline mining is a surface mining method that uses large capacity draglines to remove overburden to expose the coal seams. Shovels or loaders load coal in haul trucks for transportation to a preparation plant or unit train loadout facility. Seam recovery using the dragline method is typically 85% or more and productivity levels are similar to those for truck-and-shovel/loader mining.

Highwall Mining

Highwall mining is a surface mining method generally utilized in conjunction with truck-and-shovel/loader surface mining. At the highwall exposed by the truck-and-shovel/loader operation, a modified continuous miner with an attached beltline system cuts horizontal passages from the highwall into a seam. These passages can penetrate to a depth of up to 1,600 feet. This method typically can recover up to 65% of the reserve block penetrated.

Coal Preparation and Blending

Depending on coal quality and customer requirements, raw coal may in some cases be shipped directly from the mine to the customer. Generally, raw coal from surface mines can be shipped in this manner. However, the quality of most underground raw coal does not allow it to be shipped directly to the customer without processing in a preparation plant. Preparation plants separate impurities from coal. This processing upgrades the quality and heating value of the coal by removing or reducing sulfur and ash-producing materials, but entails additional expense and results in some loss of coal. Coals of various sulfur and ash contents can be mixed or “blended” at a preparation plant or loading facility to meet the specific combustion and environmental needs of customers. Coal blending helps increase profitability by meeting the quality requirements of specific customer contracts, while maximizing revenue through optimal use of coal inventories.

Coal Characteristics

In general, coal of all geological composition is characterized by end use as either steam coal or metallurgical coal. Heat value and sulfur content are the most important variables in the profitable marketing and transportation of steam coal, while ash, sulfur and various coking characteristics are important variables in the profitable marketing and transportation of metallurgical coal. We mine, process, market and transport bituminous steam and metallurgical coal, characteristics of which are described below.

Table of Contents

Heat Value

The heat value of coal is commonly measured in Btus per pound of coal. A Btu is the amount of heat needed to raise one pound of water one degree Fahrenheit. Coal found in the eastern and midwestern regions of the United States tends to have a heat content ranging from 10,000 to 14,000 Btus per pound, as received. As received Btus per pound includes the weight of moisture in the coal on an as sold basis. Most coal found in the Western United States ranges from 8,000 to 10,000 Btus per pound, as received.

Bituminous Coal

Bituminous coal is a relatively soft black coal with a heat content that ranges from 10,000 to 14,000 Btus per pound. This coal is located primarily in Appalachia, Arizona, Colorado, the Midwest and Utah, and is the type most commonly used for electricity generation in the United States. Bituminous coal is also used for industrial steam purposes by utility and industrial customers, and as metallurgical coal in steel production.

Sulfur Content

Sulfur content can vary from coal seam to coal seam and sometimes within each seam. When coal is burned, it produces sulfur dioxide, the amount of which varies depending on the chemical composition and the concentration of sulfur in the coal. Compliance coal is coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btus and complies with the requirements of the Clean Air Act Acid Rain program. Low sulfur coal is coal which, when burned, emits approximately 1.6 pounds or less of sulfur dioxide per million Btus. Mid-sulfur coal is characterized as coal which, when burned, emits greater than 1.6 pounds of sulfur dioxide per million Btus but less than 2.5 pounds of sulfur dioxide per million Btus. High sulfur coal is generally characterized as coal which, when burned, emits greater than 2.5 pounds per million Btus.

High sulfur coal can be burned in electric utility plants equipped with sulfur-reduction technology, such as scrubbers, which can reduce sulfur dioxide emissions by up to 99%. Plants without scrubbers can burn high sulfur coal by blending it with lower sulfur coal or by purchasing emission allowances on the open market. Each emission allowance permits the user to emit a ton of sulfur dioxide. By 2000, 90,000 megawatts of electric generation capacity utilized scrubbing technologies. According to the EIA, by 2025, an additional 27,000 megawatts of electric generation capacity will have installed scrubbers. Additional scrubbing will provide new market opportunities for our medium to high sulfur coal. All new coal-fired electric utility generation plants built in the United States will use clean coal-burning technology.

Other Characteristics

Ash is the inorganic residue remaining after the combustion of coal. As with sulfur content, ash content varies from coal seam to coal seam. Ash content is an important characteristic of coal because it increases transportation costs and electric generating plants must handle and dispose of ash following combustion.

Moisture content of coal varies by the type of coal, the region where it is mined and the location of coal within a seam. In general, high moisture content decreases the heat value per pound of coal, thereby increasing the delivered cost per Btu. Moisture content in coal, as sold, can range from approximately 5% to 30% of the coal’s weight.

Table of Contents

Operations

As of December 31, 2008, we operated a total of 14 surface and 14 underground coal mines located in Kentucky, Maryland, Virginia, West Virginia and Illinois. Approximately 57% of our production has come from surface mines, and the remaining production has come from our underground mines. These mining facilities include 10 preparation plants, each of which receive, blend, process and ship coal that is produced from one or more of our 28 active mines. Our underground mines generally consist of one or more single or dual continuous miner sections which are made up of the continuous miner, shuttle cars, roof bolters and various ancillary equipment. Our surface mines are a combination of mountain top removal, highwall contour and cross ridge operations using truck/loader equipment fleets along with large production tractors. A dragline is employed as the prime earthmover at one of our surface mines. Most of our preparation plants are modern heavy media plants that generally have both coarse and fine coal cleaning circuits. We currently own most of the equipment utilized in our mining operations. We employ preventive maintenance and rebuild programs to ensure that our equipment is modern and well maintained. The mobile equipment utilized at our mining operations is replaced on an on-going basis with new, more efficient units based on equipment age and mechanical condition. Each year we endeavor to replace the oldest units, thereby maintaining productivity while minimizing capital expenditures.

The following table provides summary information regarding our principal active operations as of December 31, 2008:

			Number and Type of Mines					
ning Complexes(1)	Location	Preparation Plants	Under-ground	Surface	Total	Mining Method (2)	Transportation	Tons Produced i 2008 (in thousand
stern	Cowen, WV	1	—	1	1	MTR, DL, TSL	Rail	3,234
zard	Hazard, KY	—	—	7	7	HW, MTR, TSL	Rail, Truck	4,055
nt Ridge	Hazard, KY	1	3	—	3	R&P	Rail, Truck	1,056
ott County	Kite, KY	1	3	—	3	R&P	Rail	948
ven	Raven, KY	1	2	—	2	R&P	Rail	664
st Kentucky	Pike Co., KY	—	—	2	2	MTR, TSL	Rail	1,058
ckley	Eccles, WV	1	1	—	1	R&P	Rail	531
ndex Energy rporation	Garrett Co., MD	1	—	3	3	CRM, TSL	Truck, Rail	939
riot Mining mpany	Monongalia Co., WV	—	—	1	1	CTR, TSL	Barge, Rail, Truck	929
olf Run Mining ckhannon Division	Upshur Co., WV	1	2	—	2	R&P	Rail, Truck	993
ntinel	Barbour Co., WV	1(3)	1	—	1	R&P	Rail	1,007
well Mountain	St. Charles, VA	1	1	—	1	R&P	Rail	100
nois	Williamsville, IL	1	1	—	1	R&P	Truck	2,261

(1) Does not include Juliana, an inactive mining complex.
(2) CRM = Cross Ridge Mining; CTR = Contour Mining; R&P = Room-and-pillar; MTR = Mountain Top Removal; DL =

Dragline; HW = Highwall; TSL = Truck and Shovel/Loader.

(3) A portion of the complex currently utilizes one circuit.

Table of Contents

The following table provides the last three years annual production for each of our mining complexes and the average prices received for our coal:

	2008		2007		2006	
Mining Complexes(1)	Tons Produced	Sales Realizations (2)	Tons Produced	Sales Realizations (2)	Tons Produced	Sales Realizations (2)
Eastern	3,234,517	$ 55.36	3,268,000	$ 42.15	3,048,800	$ 43.92
Hazard	4,055,874	$ 54.56	3,868,959	$ 45.04	3,709,924	$ 50.05
Flint Ridge	1,055,996	$ 55.05	1,306,428	$ 45.49	1,718,300	$ 50.81
Knott County	948,445	$ 52.57	1,039,714	$ 46.41	1,268,617	$ 51.51
Raven	664,265	$ 54.45	608,068	$ 48.30	246,570	$ 48.52
East Kentucky	1,058,092	$ 58.39	1,001,911	$ 51.42	1,255,522	$ 53.28
Beckley(3)	531,842	$ 106.66	39,748	$ 72.82	—	$ —
Vindex Energy Corporation	939,141	$ 54.43	853,695	$ 36.83	1,062,925	$ 36.62
Patriot Mining Company	929,645	$ 40.56	885,108	$ 25.12	888,265	$ 23.52
Wolf Run Mining Buckhannon Division	993,807	$ 56.48	636,002	$ 41.94	820,688	$ 42.46
Sentinel	1,007,425	$ 60.73	681,814	$ 47.22	58,403	$ 41.25
Sycamore Group	—	(4) $ —	82,904(4)	$ 30.14	347,241	$ 29.13
Powell Mountain(5)	100,322	$ 132.17	—	$ —	—	$ —
Illinois	2,261,028	$ 29.94	2,085,495	$ 29.84	2,084,193	$ 24.68
	17,780,399		16,357,846		16,509,448	

(1) Does not include Juliana, an inactive mining complex.
(2) Excludes freight and handling revenue.
(3) Beckley was in development until the fall of 2008.
(4) The Sycamore No. 1 mine was depleted and reclaimed in 2007.
(5) Powell Mountain was acquired in 2008.

Table of Contents

Northern and Central Appalachia Mining Operations

Below is a map showing the location and access to our coal operations in Northern and Central Appalachia:

Our Northern and Central Appalachian mining facilities and reserves are strategically located across West Virginia, Kentucky, Maryland and Virginia and are used to produce and ship coal to our customers located primarily in the eastern half of the United States. All of our Northern and Central Appalachian mining operations are union free.

Our mines in Central Appalachia produced 11.6 million tons of coal in 2008 and our mines in Northern Appalachia produced 3.9 million tons of coal in 2008. The coal produced in 2008 from our Northern and Central Appalachian mining operations was, on average, 12,214 Btu/lb., 1.3% sulfur and 12.6% ash by content. Shipments bound for electric utilities accounted for approximately 91% of the coal shipped by these mines in 2008 compared to 93% of shipments in 2007. Within each mining complex, mines have been developed at strategic locations in proximity to our preparation plants and rail shipping facilities. The mines located in Central Appalachia ship the majority of their coal by the Norfolk Southern and CSX rail lines, although production may also be delivered by truck or barge, depending on the customer.

As of December 31, 2008, these mines had 2,166 employees.

Table of Contents

Eastern

Eastern operates the Birch River surface mine, located 60 miles east of Charleston, near Cowen in Webster County, West Virginia. Birch River is extracting coal from the Freeport, Upper Kittanning, Middle Kittanning, Upper Clarion and Lower Clarion coalbeds. We estimate that Birch River controls 5.0 million tons of coal reserves. Additional potential reserves have been identified in the immediate vicinity of the Birch River mine and exploration activities are currently being conducted in order to add those potential reserves to the reserve base.

Approximately 36% of the coal reserves are leased, while approximately 64% are owned in fee. Most of the leased reserves are held by four lessors. The leases are retained by annual minimum payments and by tonnage-based royalty payments. Most leases can be renewed until all mineable and merchantable coal has been exhausted.

Overburden is removed by a dragline, excavator, front-end loaders, end dumps and bulldozers. Approximately one-third of the total coal sales are run-of-mine, while the other two-thirds are washed at Birch River's preparation plant. Coal is transported by conveyor belt from the preparation plant to Birch River's rail loadout, which is served by CSX via the A&O Railroad, a short-line carrier that is partially owned by CSX.

Hazard

Hazard currently operates seven surface mines, a unit train loadout (Kentucky River Loading) and other support facilities in eastern Kentucky, near Hazard. The coal reserves and operations were acquired in late-1997 and 1998 by AEI Resources.

Hazard's seven surface mines include East Mac & Nellie, Vicco, Rowdy Gap, County Line, Sam Campbell, Thunder Ridge and Middle Fork. The coal from these mines is being extracted from the Hazard 10, Hazard 9, Hazard 8, Hazard 7 and Hazard 5A seams. Nearly all of the coal is marketed as a blend of run-of-mine product with the remainder being washed. Overburden is removed by front-end loaders, end dumps, bulldozers and blast casting. East Mac & Nellie also utilizes a large capacity hydraulic shovel. Coal is transported by on-highway trucks from the mines to the Kentucky River Loading rail loadout, which is served by CSX. Some coal is direct shipped to the customer by truck from the mine pits.

We estimate that Hazard controls 61.9 million tons of coal reserves, plus 6.4 million tons of coal that is classified as non-reserve coal deposits. Most of the property has been adequately explored, but additional core drilling will be conducted within specified locations to better define the reserves.

Approximately 58% of Hazard's reserves are leased. Most of the leased reserves are held by seven lessors. In several cases, Hazard has multiple leases with each lessor. The leases are retained by annual minimum payments and by tonnage-based royalty payments. Most leases can be renewed until all mineable and merchantable coal has been exhausted.

Flint Ridge

As of year end, Flint Ridge, located near Breathitt County, Kentucky, was currently operating three underground mines and one preparation plant. Two underground mines operate in the Hazard 8 seam, while the third underground mine operates in the Hazard 5A seam.

Flint Ridge's three underground mines are room-and-pillar operations, utilizing continuous miners and both battery powered ram cars and shuttle cars. All of the run-of-mine coal is processed at the Flint Ridge preparation plant, which

is an existing preparation plant structure that was extensively upgraded in early 2005. Since July 2005, it has been processing coal from the Hazard and Flint Ridge mining complexes.

The majority of the processed coal is trucked to the Kentucky River Loading rail loadout. Some processed coal is trucked directly to the customer from the preparation facility.

We estimate that Flint Ridge controls 24.2 million tons of coal reserves, plus 0.9 million tons of non-reserve coal deposits. Approximately 97% of Flint Ridge's reserves are leased, while 3% are owned in fee. The leases are retained by annual minimum payments and by tonnage-based royalty payments. Most leases can be renewed until all mineable and merchantable coal has been exhausted.

Table of Contents

Knott County

Knott County operates three underground mines, the Supreme Energy preparation plant and rail loadout and other facilities necessary to support the mining operations in eastern Kentucky, near Kite. Knott County was acquired by AEI Resources from Zeigler in 1998 with reserves acquired through a lease from Penn Virginia.

Knott County is producing coal from the Hazard 4 and Elkhorn 3 coalbeds. Two mines are operating in the Hazard 4 coalbed: Calvary and Clean Energy. The Classic mine is operating in the Elkhorn 3 coalbed. Three additional properties are in the process of being permitted for underground mine development. We estimate this property contains 15.2 million tons of coal reserves. A significant portion of the property has been explored, but additional core drilling will be conducted within specified locations to better define the reserves.

Approximately 25% of Knott County's reserves are owned in fee, while approximately 75% are leased. The leases are retained by annual minimum payments and by tonnage-based royalty payments. The leases can be renewed until all mineable and merchantable coal has been exhausted.

Knott County's three underground mines are room-and-pillar operations, utilizing continuous miners and shuttle cars. Nearly all of the run-of-mine coal is processed at the Supreme Energy preparation plant; some of the Hazard 4 run-of-mine coal is blended with the washed coal. All of Knott County's coal is transported by rail from loadouts served by CSX.

Raven

Raven, located in Knott County, Kentucky, operates two underground mines and the Raven preparation plant. Raven's two underground mines are producing coal from the Elkhorn 2 coalbed. We estimate this property contains 12.2 million tons of coal reserves. Most of the property has been extensively explored, but additional core drilling will be conducted within specified locations to better define the reserves.

Raven's reserves are 100% leased from one lessor. The leases are retained by annual minimum payments and by tonnage-based royalty payments. The leases can be renewed until all mineable and merchantable coal has been exhausted.

Raven's two underground mines are room-and-pillar operations, utilizing continuous miners and battery powered ram cars. The coal is processed at the Raven preparation plant. Operations at the Raven preparation plant began in 2006 in conjunction with Loadout, LLC, an affiliate of Penn Virginia Resources Partners, L.P. Nearly all of Raven's coal is transported by rail via CSX.

East Kentucky

East Kentucky is a surface mining operation located in Martin and Pike Counties, Kentucky, near the Tug Fork River. East Kentucky currently operates the Mt. Sterling and Peelpoplar surface mines and the Sandlick loadout. The loadout is serviced by Norfolk Southern railroad. East Kentucky was acquired by AEI Resources in the second quarter of 1999.

Mt. Sterling is an area surface mine that produces coal from the Taylor, Coalburg, Winifrede, Buffalo and Stockton coalbeds. All of the coal is sold run-of-mine. We estimate that the Mt. Sterling mine controls 2.7 million tons of coal reserves, of which 88% are owned. No additional exploration is required. Overburden at the Mt. Sterling mine is removed by front-end loaders, end dumps, bulldozers and blast casting. Coal from the pits is transported by truck to

the Sandlick loadout.

Peelpoplar is a surface mine that produces coal using contour mining from the Little Fireclay and Whitesburg Middle coal seams that we estimate to control 0.2 million tons of coal reserves, none of which are owned. Mining is performed using a front-end loader/truck spread and bulldozers. Coal produced is transported by on-highway trucks to the Sandlick loadout. We plan to operate the Peelpoplar mine though 2009.

Although Mt. Sterling and Peelpoplar are mined by East Kentucky, the properties are held by ICG Natural Resources. The leases are retained by annual minimum payments and by tonnage-based royalty payments. Most leases can be renewed until all mineable and merchantable coal has been exhausted.

Table of Contents

Beckley

The Beckley Pocahontas Mine was placed into production in the fall of 2008. It is located in Central Appalachia in Raleigh County, West Virginia. The Beckley Pocahontas mine accesses a 32.0 million-ton deep reserve of high quality low-volatile metallurgical coal in the Pocahontas No. 3 seam. Most of the 16,800 acre Beckley reserve is leased from three land companies: Western Pocahontas Properties, Crab Orchard Coal Company and Beaver Coal Company.

Construction of the slope portal and a new preparation plant was completed in late 2007 with remaining development completed in 2008. Underground production is by means of the room-and-pillar method with continuous miners and battery haulers. We are marketing the coal produced from the Beckley reserve to domestic steel producers and for export. Additionally, we began marketing metallurgical coal produced from reprocessing a nearby coal refuse pile located at Eccles, West Virginia.

Vindex Energy Corporation

Vindex Energy Corporation operates three surface mines, the Carlos mine, the Island mine and the Jackson Mountain mine, all located in Garrett and Allegany Counties, Maryland. The reserves at Vindex are leased from multiple landowners under leases that expire at varying times and are renewable with annual holding costs. Vindex Energy is a cross-ridge mining operation extracting coal from the Upper Freeport, Bakerstown, Middle Kittanning, Upper Kittanning, Pittsburgh and Redstone seams. All surface mines operated by Vindex Energy are truck-and-shovel/loader mining operations and are conducted with relatively new equipment. Exploration and development is conducted on a continual basis ahead of mining. In 2007, Vindex added the Cabin Run property to its reserve base. The total reserves for the assigned surface operations at Vindex amount to approximately 7.3 million tons.

Most of the surface mine production is shipped directly to the customer as run-of-mine product. Any coal that must be washed is processed at our preparation plant located near Mount Storm, West Virginia, where the product is shipped to the customer by either truck or rail.

Patriot Mining Company

Patriot Mining Company consists of the Guston Run surface mine, located near Morgantown in Monongalia County, West Virginia. The Crown No. 4 surface mine was depleted in the third quarter of 2007 and the Fort Grand surface mine was temporarily idled in the fourth quarter of 2008. The majority of the coal and surface is leased under renewable contracts with small annual minimum holding costs. Coal is extracted from the Waynesburg seam using contour mining methods with dozers, loaders and trucks. As mining progresses, reserves are being acquired and permitted for future operations. The coal is shipped to the customer by rail, truck or barge using our barge loading facility.

We estimate that Patriot Mining Company currently controls approximately 6.2 million tons of coal reserves, of which 1% are owned.

Buckhannon Division

Wolf Run Mining Company’s Buckhannon Division currently consists of two active underground mines: the Imperial mine located in Upshur County, West Virginia, near the town of Buckhannon, and the Sycamore No. 2 mine located in Harrison County, West Virginia, approximately ten miles west of Clarksburg. Nearly all of the reserves in the Buckhannon Division are owned. The Buckhannon Division also owns the Sago mine, which was idled in March

2007. The decision was made in December 2008 to permanently close the Sago mine due to deteriorating conditions and the high cost necessary to reactivate the mine.

The Imperial mine extracts coal from the Middle Kittanning seam. All of the coal extracted from the Imperial mine is processed through the nearby Sawmill Run preparation plant. This coal is primarily shipped by CSX rail with origination by the A&O Railroad, a short-line operator, although some coal is trucked to local industrial customers. The reserves at the Buckhannon Division have characteristics that make it marketable to both steam and export metallurgical coal customers.

The Sycamore No. 2 mine began producing coal from the Pittsburgh seam by the room-and-pillar mining method with continuous miners and shuttle cars in the fourth quarter of 2005. The reserve is primarily leased from one landowner with an annual minimum holding costs and an automatic renewal based on an annual minimum production of 250,000 tons. Unexpected adverse mining conditions forced the idling of the Sycamore No. 2 mine during the third quarter of 2006; however, an independent contractor resumed production at the mine in September 2007. The coal produced from the Sycamore No. 2 mine is sold on a raw basis and shipped to Allegheny Power Service Corporation’s Harrison Power Station by truck.

Powell Mountain

Acquired in 2008, Powell Mountain, located in Lee County, Virginia and Harlan County, Kentucky, currently operates the Darby mine, a room-and-pillar mine operating two sections with both shuttle cars and ram cars. The mine is operating in the Darby seam with all coal being trucked to the Mayflower preparation plant for processing. Coal is shipped by rail through the dual service rail loadout facility with rail service provided by both the Norfolk Southern and CSX railroads. Some purchased coal is brought into the facility for processing and blending. We plan to begin operation of the new Middle Splint mine in 2010.

Sentinel

Wolf Run Mining Company’s Sentinel mine, located in Barbour County, West Virginia, was acquired by Anker in 1990 and has been operating ever since. Historically, coal was extracted from the Upper and Lower Kittanning seams; however, the mine was idled in the second quarter of 2006 to extend the slope and shafts to the underlying Clarion seam. Developmental mining in the Clarion seam began in November 2006 and the current operation now includes three continuous miner sections using the room-and-pillar mining method. Clarion coalbed reserves at the Sentinel mine amount to approximately 15.4 million tons, of which approximately 12% is owned and 88% is leased.

Coal is fed directly from the mine to a preparation plant and loadout facility served by the CSX railroad with origination by the A&O Railroad, as short-line operator. The product can be shipped to steam or metallurgical markets.

Table of Contents

New Appalachian Mine Developments

Hillman Property

The Hillman property, located in Taylor County, West Virginia, near Grafton, includes approximately 186.0 million tons of deep coal reserves of both steam and metallurgical quality coal in the Lower Kittanning seam covering approximately 65,000 acres. The reserve extends into parts of Barbour, Marion and Harrison Counties as well. ICG owns the Hillman coal reserve in addition to nearly 4,000 acres of surface property to accommodate the development of two projected mining operations. In addition to the Lower Kittanning reserves, we also own significant non-reserve coal deposits in the Kittanning, Freeport, Clarion and Mercer seams on the Hillman property.

The West Virginia Department of Environmental Protection ("WVDEP") issued a permit on June 5, 2007 for the Tygart No. 1 underground longwall mine and preparation plant complex located on the Hillman Property. On appeal, the WV Surface Mine Board remanded the permit for additional modifications. The modified permit application was approved in April 2008 and mine site development commenced. A subsequent appeal to the WV Surface Mine Board resulted in the suspension of the permit in October 2008 and cessation of construction activity. A modified permit application is awaiting reissuance from WVDEP.

Construction of our Tygart No. 1 mining complex is not expected to resume until market conditions justify the additional production. We will continue to evaluate timing of the development as market conditions evolve, but resumption of work is not currently expected before 2011. At full production, we expect Tygart No. 1 to produce 3.5 million tons annually of high quality coal that is well suited to both the utility market and the high volatile metallurgical market.

Upshur Property

The Upshur Property, located in Northern Appalachia, contains approximately 93.0 million tons of non-reserve coal deposits owned or controlled by us in the Middle and Lower Kittanning seams. Due to unique geologic characteristics and coal quality constraints, Upshur is a potential location for an on-site power plant. Some preliminary research, including air quality monitoring, has been completed as part of conceptual planning for the future construction of a circulating fluidized bed power plant at Upshur.

Big Creek Property

Our Big Creek reserve, located in Central Appalachia, covers 10,000 acres of leased coal lands located north of the town of Richlands in Tazewell County, Virginia. Total recoverable reserves are 25.9 million tons in the Jawbone, Greasy Creek and War Creek seams. The Big Creek reserve is all leased from Southern Regional Industrial Realty. The War Creek mine, which is permitted as a room-and-pillar mining operation, is expected to be developed in the future as market conditions warrant. We receive an overriding royalty on coalbed methane production from this property.

Juliana Complex

The Juliana property, located in Webster County, West Virginia, was extensively mined in the past by a predecessor of ICG. Contour and mountaintop removal surface mining methods were utilized to produce coal from the Kittanning and Upper Freeport seams. In addition, a substantial amount of deep-mined coal was produced from the Middle Kittanning seam.

Currently at Juliana, there are two Kittanning deep mine permits and one surface mine permit in place. Permitted deep and surface non-reserve coal deposits are 1.2 million tons and 1.9 million tons, respectively.

Jennie Creek Property

The Jennie Creek reserve, located in Mingo County, West Virginia, is a 44.9 million ton reserve of surface and deep mineable steam coal. This property contains 14.7 million tons of surface mineable, low sulfur coal reserves. A deep reserve in the high Btu, mid-sulfur Alma seam constitutes the largest block of coal at 30.2 million tons. Permitting is now in progress for a surface mine on this Central Appalachian property. Development of the entire Jennie Creek reserve had been subject to the resolution of certain disputes with lessors arising out of the Horizon bankruptcy proceedings. We resolved our litigation with the lessors of the Jennie Creek coal reserves in 2007. Using the results of an extensive core drilling project completed on the property in 2007 and 2008, the surface mine plan was updated and corresponding changes are being made to the mining permits. The coal will be produced by contouring, highwall mining and area mining.

Table of Contents

Illinois Basin Mining Operations

Below is a map showing the location and access to our coal operations in the Illinois Basin:

Illinois operates one large underground coal mine, the Viper mine, in central Illinois. Viper commenced mining operations in 1982 as a union free operation for Shell Oil Company. Viper was acquired by Ziegler in 1992 and subsequently acquired by AEI Resources in 1998.

The Viper mine is mining the Illinois No. 5 Seam, also referred to as the Springfield Seam. We estimate that Viper controls approximately 42.6 million tons of coal reserves, plus an additional 38.5 million tons of non-reserve coal deposits.

Approximately 79% of the coal reserves are leased, while 21% are owned in fee. The leases are retained by annual minimum payments and by tonnage-based royalty payments. The leases can be renewed until all mineable and merchantable coal has been exhausted.

The Viper mine is a room-and-pillar operation, utilizing continuous miners and battery coal haulers. Management believes that Illinois is one of the lowest cost and highest productivity mines in the Illinois Basin. All of the raw coal is processed at Viper's preparation plant. The clean coal is transported to utility and industrial customers located in North Central Illinois by on-highway trucks operated by independent trucking companies. A major rail line is located a short distance from the plant, giving Viper the option of constructing a rail loadout. Shipments to electric utilities account for approximately 64% of coal sales.

The underground equipment, infrastructure and preparation plant are well maintained. Underground equipment is routinely replaced or rebuilt depending on the age and mechanical condition of the equipment. Illinois plans to develop a new portal facility that will allow it to eliminate the need to operate over five miles of underground beltlines and to maintain the extensive previously mined area.

Table of Contents

Other Operations

Brokered coal sales

In addition to the coal we mine, we purchase and resell coal produced by third parties from their controlled reserves to meet our customers' specifications.

ADDCAR Systems

In our highwall mining business, we have five systems in operation using our patented ADDCAR highwall mining system and intend to build additional ADDCAR systems as required. ADDCAR(TM) is the registered trademark of ICG. The ADDCAR highwall mining system is an innovative and efficient mining system often deployed at reserves that cannot be economically mined by other methods.

A typical ADDCAR highwall mining system consists of a launch vehicle, continuous miner, conveyor cars, a stacker conveyor, electric generator, water tanker for cooling and dust suppression and a wheel loader with forklift attachment.

A five person crew operates the entire ADDCAR highwall mining system with control of the continuous miner being performed remotely by one person from the climate-controlled cab located at the rear of the launch vehicle. Our system utilizes a navigational package to provide horizontal guidance, which helps to control rib width, and thus roof stability. In addition, the system provides vertical guidance for avoiding or limiting out of seam dilutions. The ADDCAR highwall mining system is equipped with high-quality video monitors to provide the operator with visual displays of the mining process from inside each entry being mined.

The mining cycle begins by aligning the ADDCAR highwall mining system onto the desired heading and starting the entry. As the remotely controlled continuous miner penetrates the coal seam, ADDCAR conveyor cars are added behind it, forming a continuous cascading conveyor train. This continues until the entry is at the planned full depth of up to 1,200 to 1,500 feet. After retraction, the launch vehicle is moved to the next entry, leaving a support pillar of coal between entries. This process recovers as much as 65% of the reserves while keeping all personnel outside the coal seam in a safe working environment. A wide range of seam heights can be mined with high production in seams as low as 3.5 feet and as high as 15 feet in a single pass. If the seam height is greater than 15 feet, then multi-lifts can be mined to create an unlimited entry height. The navigational features on the ADDCAR highwall mining system allow for multi-lift mining while ensuring that the designed pillar width is maintained.

During the mining cycle, in addition to the tramming effort provided by the crawler drive of the continuous miner, the ADDCAR highwall mining system increases the cutting capability of the machine through additional forces provided by hydraulic cylinders which transmit thrust to the back of the miner through blocks mounted on the side of the conveyor cars. This additional energy allows the continuous miner to achieve maximum cutting and loading rates as it moves forward into the seam. The first ADDCAR narrow bench mining system was placed in operation in 2007.

We currently have the exclusive North American distribution rights for the ADDCAR highwall mining system.

Table of Contents

Coalbed methane

CoalQuest has entered into a lease and joint operating agreement pursuant to which it leases coalbed methane, which is pipeline quality gas that resides in coal seams, and participates in certain coalbed methane wells, from its properties in Barbour, Harrison and Taylor counties in West Virginia. The first production well owned in part by CoalQuest began commercial operations in June 2006 and ten additional wells partially owned by CoalQuest were brought online by the end of 2007. During 2008, the counterparty to the lease and joint operating agreement declared bankruptcy. As a result, we recorded a reserve against related outstanding accounts receivable. The counterparty continues to operate the wells under the protection of the bankruptcy court. Our coalbed methane lessee developed other wells in which CoalQuest is not a partial owner. In the eastern United States, conventional natural gas fields are typically located in various sedimentary formations at depths ranging from 2,000 to 15,000 feet. Exploration companies often put capital at risk by searching for gas in commercially exploitable quantities at these depths. By contrast, the coal seams from which we recover coalbed methane are typically less than 1,000 feet deep and are usually better defined than deeper formations. We believe that this contributes to lower exploration costs than those incurred by producers that operate in deeper, less defined formations. We believe this project is part of the first application of proprietary horizontal drilling technology for coalbed methane in northern West Virginia coalfields. We have not filed reserve estimates with any federal agency.

We receive an overriding royalty on coalbed methane production from the Crab Orchard Coal Company and Beaver Coal Company coal reserves leased by ICG Beckley in Raleigh County, West Virginia and from the leased Big Creek coal reserves in Tazewell County, Virginia. We also lease coalbed methane from certain of our properties in Kentucky and will receive rents and royalties on future production.

Customers and Coal Contracts

Customers

Our primary customers are investment grade electric utility companies primarily in the eastern half of the United States. 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 of our customers. Our three largest customers for the year ended December 31, 2008 were Progress Energy, Georgia Power Company and Allegheny Energy Supply Company and we derived approximately 32% of our coal revenues from sales to our five largest customers. We did not derive more than 10% of our coal sales revenues from any single customer in 2008.

Long-term coal supply agreements

As is customary in the coal industry, we enter into long-term supply contracts (exceeding one year in duration) with many of our customers when market conditions are appropriate. These contracts allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales price. For the year ended December 31, 2008, approximately 51% of our revenues were derived from long-term supply contracts. We sell the remainder of our coal through short-term contracts and on the spot market. We have also entered into certain brokered transactions to purchase certain amounts of coal to meet our sales commitments. These purchase coal contracts expire between 2009 and 2010 and are expected to provide us a minimum of approximately 1.9 million tons of coal through the remaining lives of the contracts.

We have certain contracts which are below current market rates because they were entered into during periods of suppressed coal prices. As the net costs associated with producing coal have increased due to higher energy, transportation and steel prices, the price adjustment mechanisms within several of our long-term contracts do not

reflect current market prices. This has resulted in certain counterparties to these contracts benefiting from below-market prices for our coal.

Table of Contents

The terms of our coal supply agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary significantly by customer, including price adjustment features, price reopener terms, coal quality requirements, quantity adjustment mechanisms, permitted sources of supply, future regulatory changes, extension options, force majeure provisions and termination and assignment provisions.

Some of our long-term contracts provide for a pre-determined adjustment to the stipulated base price at times specified in the agreement or at other periodic intervals to account for changes due to inflation or deflation in prevailing market prices.

In addition, most of our contracts contain provisions to adjust the base price due to new statutes, ordinances or regulations that impact our costs related to performance of the agreement. Also, some of our contracts contain provisions that allow for the recovery of costs impacted by modifications or changes in the interpretations or application of any applicable government statutes.

Price reopener provisions are present in many of our long-term contracts. These price reopener provisions may automatically set a new price based on prevailing market price or, in some instances, require the parties to agree on a new price, sometimes within a specified range of prices. In a limited number of agreements, failure of the parties to agree on a price under a price reopener provision can lead to termination of the contract. Under some of our contracts, we have the right to match lower prices offered to our customers by other suppliers.

Quality and volumes for the coal are stipulated in coal supply agreements and, in some instances, buyers have the option to vary annual or monthly volumes. Most of our coal supply agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content, sulfur, ash, hardness and ash fusion temperature. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts.

Transportation/Logistics

We ship coal to our customers by rail, truck or barge. We typically pay the transportation costs for our coal to be delivered to the barge or rail loadout facility, where the coal is then loaded for final delivery. Once the coal is loaded in the barge or railcar, our customer is typically responsible for the freight costs to the ultimate destination. Transportation costs vary greatly based on the customer’s proximity to the mine and our proximity to the loadout facilities. We use a variety of independent companies for our transportation needs and typically enter into multiple agreements with transportation companies throughout the year.

In 2008, approximately 98% of our coal (both produced and purchased) from our Central Appalachian operations was delivered to our customers by rail generally on either the Norfolk Southern or CSX rail lines, with the remaining 2% delivered by truck. For our Illinois Basin operations, all of our coal was delivered by truck to customers, generally within an 80 mile radius of our Illinois mine.

We believe we enjoy good relationships with rail carriers and barge companies due, in part, to our modern coal-loading facilities and the experience of our transportation and distribution employees.

Suppliers

In 2008, we spent more than $375.6 million to procure goods and services in support of our business activities, excluding capital expenditures. Principal commodities include maintenance and repair parts and services, fuel, roof control and support items, explosives, tires, conveyance structure, ventilation supplies and lubricants. Our outside

suppliers perform a significant portion of our equipment rebuilds and repairs both on- and off-site, as well as construction and reclamation activities.

Each of our regional mining operations has developed its own supplier base consistent with local needs. We have a centralized sourcing group for major supplier contract negotiation and administration, for the negotiation and purchase of major capital goods and to support the business units. The supplier base has been relatively stable for many years, but there has been some consolidation. We are not dependent on any one supplier in any region. We promote competition between suppliers and seek to develop relationships with those suppliers whose focus is on lowering our costs. We seek suppliers who identify and concentrate on implementing continuous improvement opportunities within their area of expertise.

Table of Contents

Competition

The coal industry is intensely competitive. Our main competitors are Massey Energy Company, Arch Coal, Consol Energy, Alpha Natural Resources, Foundation Coal Holdings, James River Coal Company, Patriot Coal Corporation and various other smaller, independent producers. The most important factors on which we compete are coal price at the mine, coal quality and characteristics, transportation costs and the reliability of supply. Demand for coal and the prices that we are able to obtain for our coal are closely linked to coal consumption patterns of the domestic electric generation industry, which accounted for approximately 93% of domestic coal consumption in 2007. These coal consumption patterns are influenced by factors beyond our control, including the demand for electricity which is significantly dependent upon economic activity and summer and winter temperatures in the United States, government regulation, technological developments and the location, availability, quality and price of competing sources of coal, changes in international supply and demand, alternative fuels such as natural gas, oil and nuclear and alternative energy sources, such as hydroelectric power.

Employees

As of December 31, 2008, we had 2,727 employees of which 22% were salaried and 78% were hourly. We believe our relationship with our employees is positive. Our entire workforce is union free.

Reclamation

Reclamation expenses are a significant part of any coal mining operation. Prior to commencing mining operations, a company is required to apply for numerous permits in the state where the mining is to occur. Before a state will approve and issue these permits, it typically requires the mine operator to present a reclamation plan which meets regulatory criteria and to secure a surety bond to guarantee performance of reclamation in an amount determined under state law. Bonding companies also require posting of collateral, typically in the form of letters of credit, to secure the surety bonds. As of December 31, 2008, the Company had $61.1 million in letters of credit supporting its reclamation surety bonds. While bonds are issued against reclamation liability for a particular permit at a particular site, collateral posted in support of the bond is not allocated to a specific bond, but instead is part of a collateral pool supporting all bonds issued by that particular insurer. Bonds are released in phases as reclamation is completed in a particular area.

Environmental, Safety and Other Regulatory Matters

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as permitting and licensing requirements, employee health and safety, air quality standards, water pollution, plant and wildlife protection, the reclamation and restoration of mining properties after mining has been completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects of mining on groundwater quality and availability. These laws and regulations have had, and will continue to have, a significant effect on our costs of production and competitive position. Future legislation, regulations or orders may be adopted or become effective which may adversely affect our mining operations, cost structure or the ability of our customers to use coal. For instance, new legislation, regulations or orders, as well as future interpretations and more rigorous enforcement of existing laws, may require substantial increases in equipment and operating costs to us and delays, interruptions or a termination of operations, the extent of which we cannot predict. Future legislation, regulations or orders may also cause coal to become a less attractive fuel source, resulting in a reduction in coal’s share of the market for fuels used to generate electricity.

We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, due in part to the extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time in the industry and at our operations.

Table of Contents

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, we may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production or processing of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations. Applications for permits are subject to public comment and may be subject to litigation from environmental groups or other third parties seeking to deny issuance of a permit, which may also delay commencement or continuation of mining operations. Regulations also 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 could provide a basis to revoke existing permits and to deny the issuance of additional permits.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically, we submit our necessary mining permit applications for our planned mines promptly upon securing the necessary property rights and required geologic and environmental data. In our experience, mining permit approvals generally require 12 to 18 months after initial submission.

Surface Mining Control and Reclamation Act

The Surface Mining Control and Reclamation Act of 1977 (“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. Mine operators must obtain SMCRA permits and permit renewals from the OSM, or the appropriate state regulatory agency, for authorization of certain mining operations that result in a disturbance of the surface. If a state adopts a regulatory program as comprehensive as the federal mining program under SMCRA, the state becomes the regulatory authority. States in which we have active mining operations have achieved primary control of enforcement through federal approval of the state program.

SMCRA permit provisions include requirements for coal prospecting, mine plan development, topsoil removal, storage and replacement, selective handling of overburden materials, mine pit backfilling and grading, protection of the hydrologic balance, subsidence control for underground mines, surface drainage control, mine drainage and mine discharge control and treatment and revegetation. These requirements seek to limit the adverse impacts of coal mining and more restrictive requirements may be adopted from time to time.

The mining permit application process is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of cultural resources, soils, vegetation, wildlife, assessment of surface and ground water hydrology, climatology and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that it will mine. We develop mine and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mine and reclamation plan incorporates the provisions of SMCRA, the state programs and the complementary environmental programs that impact coal mining.

Also included in the permit application are documents defining ownership and agreements pertaining to coal, minerals, oil and gas, water rights, rights of way and surface land, and documents required by the OSM’s Applicant Violator System, including the mining and compliance history of officers, directors and principal owners of the entity.

Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness review and technical review. Public notice and opportunity for public comment on a proposed permit is required before a permit can be issued. Some SMCRA mine permits take over a year to prepare, depending on the size and complexity of the mine and typically take 12 to 18 months, or even longer, to be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public has rights to comment on, and otherwise engage in, the permitting process, including through intervention in the courts.

Table of Contents

Before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of reclamation obligations. The Abandoned Mine Land Fund, which is part of SMCRA, requires a fee on all coal produced. The proceeds are used to reclaim mine lands closed or abandoned prior to 1977. On December 7, 2006, the Abandoned Mine Land Program was extended for 15 years.

SMCRA stipulates compliance with many other major environmental statutes, including: the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act ("RCRA"), and the Comprehensive Environmental Response, Compensation and Liability Act ("Superfund").

Surety Bonds

Federal and state laws require us to obtain surety bonds to secure payment of certain long-term obligations including mine closure or reclamation costs, federal and state workers' compensation costs, coal leases and other miscellaneous obligations. Many of these bonds are renewable on a yearly basis.

Surety bond costs have increased in recent years while the market terms of such bonds have generally become more unfavorable. In addition, the number of companies willing to issue surety bonds has decreased. Bonding companies also require posting of collateral, typically in the form of letters of credit, to secure the surety bonds. As of December 31, 2008, the Company had $73.6 million in letters of credit supporting its surety bonds, including reclamation bonds.

Clean Air Act

The federal Clean Air Act, and comparable state laws that regulate air emissions, directly affect coal mining operations, but have a far greater indirect effect. Direct impacts on coal mining and processing operations may occur through permitting requirements and/or emission control requirements relating to particulate matter, such as fugitive dust or fine particulate matter measuring 2.5 micrometers in diameter or smaller. The Clean Air Act indirectly affects coal mining operations by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal-fired electricity generating plants and coke ovens. The general effect of such extensive regulation of emissions from coal-fired power plants could be to reduce demand for coal.

Clean Air Act requirements that may directly or indirectly affect our operations include the following:

Acid Rain

Title IV of the Clean Air Act required a two-phase reduction of sulfur dioxide emissions by electric utilities. Phase II became effective in 2000 and extended the Title IV requirements to all coal-fired power plants with generating capacity greater than 25 megawatts. The affected electricity generators have sought to meet these requirements by, among other compliance methods, switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing sulfur dioxide emission allowances. We cannot accurately predict the effect of these provisions of the Clean Air Act on us in future years. At this time, we believe that implementation of Phase II has resulted in an upward pressure on the price of lower sulfur coals as coal-fired power plants continue to comply with the more stringent restrictions of Title IV.

Fine Particulate Matter and Ozone

The Clean Air Act requires the U.S. Environmental Protection Agency (the "EPA") to set standards, referred to as National Ambient Air Quality Standards ("NAAQS") for certain pollutants. Areas that are not in compliance with these standards ("non-attainment areas") must take steps to reduce emissions levels. In 1997, the EPA revised the NAAQS for

particulate matter and ozone; although previously subject to legal challenge, these revisions were subsequently upheld, but implementation was delayed for several years.

Table of Contents

For ozone, these changes include replacement of the existing one-hour average standard with a more stringent eight-hour average standard. On April 15, 2004, the EPA announced that counties in 32 states failed to meet the new eight-hour standard for ozone. The EPA is also considering whether to revise the ozone standard. States which fail to meet the new standard had until June 2007 to develop plans for pollution control measures that allow them to come into compliance with the standards. On January 16, 2009, the EPA proposed additional requirements for non-attainment areas that could impose new requirements on power plants.

For particulates, the changes include retaining the existing standard for particulate matter with an aerodynamic diameter less than or equal to 10 microns and adding a new standard for fine particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ("PM2.5"). Following identification of non-attainment areas, each individual state will identify the sources of emissions and develop emission reduction plans. These plans may be state-specific or regional in scope. Under the Clean Air Act, individual states have up to twelve years from the date of designation to secure emissions reductions from sources contributing to the problem. In addition, on April 25, 2005, the EPA issued a finding that states have failed to submit State Implementation Plans that satisfy the requirements of the Clean Air Act with respect to the interstate transport of pollutants relative to the achievement of the 8-hour ozone and the PM2.5 standards. Because of this finding, the EPA must promulgate a Federal Implementation Plan for any state which does not submit its own plan. The EPA issued a more stringent PM2.5 standard which became effective December 18, 2006. On December 22, 2008, the EPA identified portions of 25 states as being in non-attainment with the PM2.5 standard. Meeting the new PM2.5 standard may require reductions of nitrogen oxide and sulfur dioxide emissions. Future regulation and enforcement of these new ozone and PM2.5 standards will affect many power plants, especially coal-fired plants and all plants in non-attainment areas.

Significant additional emissions control expenditures will be required at coal-fired power plants to meet the current NAAQS for ozone. Nitrogen oxides, which are a by-product of coal combustion, can lead to the creation of ozone. Accordingly, emissions control requirements for new and expanded coal-fired power plants and industrial boilers will continue to become more demanding in the years ahead.

NOx SIP Call

The NOx SIP Call program was established by the EPA in October of 1998 to reduce the transport of ozone on prevailing winds from the Midwest and South to states in the Northeast, which said they could not meet federal air quality standards because of migrating pollution. Under Phase I of the program, the EPA requires 900,000 tons of nitrogen oxide reductions from power plants in 22 states east of the Mississippi River and the District of Columbia beginning in May 2004. Phase II of the rule required a further reduction of about 100,000 tons of nitrogen oxides per year by May 1, 2007. Installation of additional control measures required under the final rules, such as selective catalytic reduction devices, will make it more costly to operate coal-fired electricity generating plants, thereby making coal a less attractive fuel.

Interstate Air Quality Rule

On March 10, 2005, the EPA adopted new rules for reducing emissions of sulfur dioxide and nitrogen oxides. This Clean Air Interstate Rule calls for power plants in 29 eastern states and the District of Columbia to reduce emission levels of sulfur dioxide and nitrous oxide. The rule regulates these pollutants under a cap and trade program similar to the system now in effect for acid deposition control. The stringency of the cap may require many coal-fired sources to install additional pollution control equipment, such as wet scrubbers. This increased sulfur emission removal capability pursuant to this rule could result in decreased demand for low sulfur coal, potentially driving down prices for low sulfur coal. Emissions would be permanently capped and could not increase. The rule seeks to cut sulfur dioxide emissions by 45% in 2010 and by 57% in 2015. On December 23, 2008, the United States Court of Appeals

for the District of Columbia remanded, without vacating, the Clean Air Interstate Rule to the EPA for further proceedings consistent with the Court's July 11, 2008 opinion which found numerous fatal flaws in the Rule. The EPA has not determined how to respond to the Court's decision.

Table of Contents

Mercury

The EPA has announced that it intends to initiate a rulemaking to adopt technology-based standards for mercury emissions from coal-fired power plants in response to a court order which vacated and remanded its 2005 Clean Air Mercury Rule, which would have reduced mercury emissions from such plants by a nationwide average of nearly 70%. The parties that overturned this rule seek even reductions in mercury emissions uniformly applied to all power plants. Some parties contend that during the pendency of this rulemaking, these plants are subject to mercury emission limitations determined on a case-by-case basis applying maximum achievable control technology.

Other proposals for controlling mercury emissions from coal-fired power plants have been made, such as establishing state or regional emission standards. If these proposals were enacted, the mercury content and variability of our coal would become a factor in future sales. In addition, seven Northeastern states have prepared and submitted to the EPA a Northeast Regional Mercury Total Maximum Daily Load to reduce mercury in waterbodies by reducing air deposition of mercury primarily from coal-fired power plants in the Midwest.

Carbon Dioxide

In February 2003, a number of states notified the EPA that they planned to sue the agency to force it to set new source performance standards for utility emissions of carbon dioxide and to tighten existing standards for sulfur dioxide and particulate matter for utility emissions. In June 2003, three of these states sued the EPA seeking a court order requiring the EPA to designate carbon dioxide as a criteria pollutant and to issue a new NAAQS for carbon dioxide. If these lawsuits result in the issuance of a court order requiring the EPA to set emission limitations for carbon dioxide and/or lower emission limitations for sulfur dioxide and particulate matter, it could reduce the amount of coal our customers would purchase from us.

Regional Haze

The EPA has initiated a regional haze program designed to protect and improve visibility at and around national parks, national wilderness areas and international parks. This program restricts the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas. Moreover, this program may require certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides, volatile organic chemicals and particulate matter. These limitations could affect the future market for coal. On July 6, 2005, the EPA issued regulations revising its regional haze program.

Clean Water Act

The federal Clean Water Act (“CWA”) and corresponding state laws affect coal mining operations by imposing restrictions on the discharge of certain pollutants into water and on dredging and filling wetlands and jurisdictional waters. The CWA establishes in-stream water quality standards and treatment standards for wastewater discharge through the National Pollutant Discharge Elimination System (“NPDES”). Regular monitoring, as well as compliance with reporting requirements and performance standards, are preconditions for the issuance and renewal of NPDES permits that govern the discharge of pollutants into water.

Table of Contents

Permits under Section 404 of the CWA are required for coal companies to conduct dredging or filling activities in jurisdictional waters for the purpose of conducting any instream activities, including installing culverts, creating water impoundments, constructing refuse areas, creating slurry ponds, placing valley fills or performing other mining activities. Jurisdictional waters typically include intermittent and perennial streams and may, in certain instances, include man-made conveyances that have a hydrologic connection to a stream or wetland. The Army Corps of Engineers ("ACOE") authorizes in-stream activities under either a general "nationwide" permit or under an individual permit, based on the expected environmental impact. A nationwide permit may be issued for specific categories of filling activity that are determined to have minimal environmental adverse effects; however, the effective term of such permits is limited to no longer than five years. Nationwide Permit 21 authorizes the disposal of dredge-and-fill material from mining activities into the waters of the United States. An individual permit typically requires a more comprehensive application process, including public notice and comment, but an individual permit can be issued for the project life. We have secured nationwide permits and individual permits, depending on the expected duration and timing of the proposed in-stream activity.

Judge Robert C. Chambers of the U.S. District Court for the Southern District of West Virginia ruled in March 2007 in a lawsuit filed by several citizen groups against the ACOE that the ACOE failed to adequately assess the impacts of surface mining on headwaters and approved mitigation that did not appropriately compensate for stream losses. Judge Chambers in June 2007 found that sediment ponds situated within a stream channel violated the prohibition against using the waters of the U.S. for waste treatment and further decided that using the reach of stream between a valley fill and the sediment pond to transport sediment-laden runoff is prohibited by the Clean Water Act. In February 2009, the Fourth Circuit Court of Appeals overturned these decisions and remanded the case for further proceedings.

On December 6, 2007, the Sierra Club and Kentucky Waterways Alliance sued the ACOE in the U.S. District Court for the Western District of Kentucky alleging that the ACOE Louisville District wrongfully issued a Section 404 authorization to ICG Hazard's Thunder Ridge surface mine in Perry County, Kentucky. The plaintiffs, who are represented by the same counsel as the plaintiffs in the Chambers lawsuit, make essentially the same claims but add the charge that the ACOE violated the National Environmental Policy Act requirement that stream impacts first must be avoided or in the alternative minimized. On December 26, 2007, the ACOE suspended the Section 404 permit to allow it to review and supplement as needed the administrative record on which the permit decision is based. We are cooperating with the ACOE in defending the ACOE's decision to issue the permit. Our Thunder Ridge surface mine continues to operate on previously permitted areas and, in accordance with an agreement reached among the parties, on certain portions of the newly permitted area.

On October 23, 2003, several citizens groups sued the ACOE in the U.S. District Court for the Southern District of West Virginia seeking to invalidate "nationwide" permits utilized by the ACOE and the coal industry for permitting most in-stream disturbances associated with coal mining, including excess spoil valley fills and refuse impoundments. Although the lower court enjoined the issuance of authorizations under Nationwide Permit 21, that decision was overturned by the Fourth Circuit Court of Appeals, which concluded that the ACOE complied with the Clean Water Act in promulgating Nationwide Permit 21. While this case remained dormant since the appeals court decision, the judge asked the parties to brief the court regarding the effects of the Chambers' decision on the Nationwide Permit 21 program. The requested briefs were filed in 2008 and the case is pending decision or further directive by the court.

A lawsuit making similar claims regarding the Nationwide Permit 21 filed in the United States Court for the Eastern District of Kentucky by a number of environmental groups is still pending. This suit also seeks, among other things, an injunction preventing the ACOE from authorizing pursuant to Nationwide Permit 21 "further discharges of mining rock, dirt or coal refuse into valley fills or surface impoundments" associated with certain specific mining permits, including permits issued to some of our mines in Kentucky. Granting of such relief would interfere with the further operation of these mines. The judge ordered a briefing schedule for the parties in this litigation.

In September 2008 the Sixth Circuit Court of Appeals partly affirmed and partly rejected a federal district court's decision that had upheld EPA's approval of Kentucky's new anti-degradation regulations. Anti-degradation regulations prohibit diminution of water quality in streams. The circuit court upheld Kentucky's methodology for designating high quality waters, even though environmental groups claimed the methodology resulted in too few high quality designations. The circuit court also affirmed Kentucky's designation method on a water body-by-water body approach and rejected environmentalist claims that such designations must be conducted on a parameter by parameter basis. The court also upheld Kentucky's exclusion of "impaired" waters from anti-degradation review. However, the circuit court struck down the district court's approval of Kentucky's alternative anti-degradation implementation procedures for coal mining. See "Legal Proceedings" contained in Item 3 of this Annual Report on Form 10-K.

Mine Safety and Health

Stringent health and safety standards have been in effect since Congress enacted the Coal Mine Health and Safety Act of 1969. The Federal 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. 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 U.S. industry. The federal Mine Improvement and New Emergency Response Act of 2006 (the "MINER Act") was signed into law on June 15, 2006 and implementation of the specific requirements of the MINER Act is currently underway. The Mine Safety and Health Administration ("MSHA") issued an emergency temporary standard addressing sealing of abandoned areas in underground mines on May 22, 2007 and on September 6, 2007, MSHA published a proposed rule that would implement Section 4 of the MINER Act by addressing composition and certification of mine rescue teams and improving their availability and training. While mine safety and health regulation has a significant effect on our operating costs, our U.S. competitors are subject to the same degree of regulation. However, pending legislation in various states could result in differing operating costs in different states and, therefore, our competitors operating in states with less stringent new legislation may not be subject to the same degree of regulation.

Table of Contents

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must secure payment of federal black lung benefits to claimants who are current and former employees and to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973. The trust fund is funded by an excise tax on production of up to $1.10 per ton for underground coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price. The excise tax does not apply to coal shipped outside the United States. In 2008, we recorded $11.8 million of expense related to this excise tax.

Resource Conservation and Recovery Act

The RCRA affects coal mining operations by establishing requirements for the treatment, storage and disposal of hazardous wastes. Certain coal mine wastes, such as overburden and coal cleaning wastes, are exempted from hazardous waste management.

Subtitle C of the RCRA exempted fossil fuel combustion by-products (“CCBs”) from hazardous waste regulation until the EPA completed a report to Congress and, in 1993, made a determination on whether the CCBs should be regulated as hazardous. In the 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion by-products generated at electric utility and independent power producing facilities, such as coal ash.

In May 2000, the EPA concluded that CCBs do not warrant regulation as hazardous waste under the RCRA and that the hazardous waste exemption applied to these CCBs. However, the EPA has determined that national non-hazardous waste regulations under the RCRA Subtitle D are needed for CCBs disposed in surface impoundments and landfills and used as mine-fill. The agency also concluded beneficial uses of these CCBs, other than for mine-filling, pose no significant risk and no additional national regulations are needed. As long as the exemption remains in effect, it is not anticipated that regulation of CCBs will have any material effect on the amount of coal used by electricity generators. Most state hazardous waste laws also exempt CCBs and instead treat them as either a solid waste or a special waste. Efforts continue by environmental groups and others for the adoption of more stringent disposal requirements for CCBs. Any increased costs associated with handling or disposal of CCBs would increase our customers’ operating costs and potentially reduce their coal purchases. In addition, contamination caused by the past disposal of ash can lead to material liability.

Due to the hazardous waste exemption for CCBs such as ash, some of the CCBs are currently put to beneficial use. For example, at certain mines, the Company sometimes uses ash deposits from the combustion of coal as a beneficial use under its reclamation plan. The alkaline ash used for this purpose serves to help alleviate the potential for acid mine drainage.

Federal and State Superfund Statutes

Superfund and similar state laws affect coal mining and hard rock operations by creating liability for investigation and remediation in response to releases of hazardous substances into the environment and for damages to natural resources caused by such releases. Under Superfund, joint and several liability may be imposed on waste generators, site owners or operators and others regardless of fault. In addition, mining operations may have reporting obligations under these laws.

Table of Contents

Climate Change

Global climate change has a potentially far-reaching impact upon our business. Concerns over measurements, estimates and projections of global climate change, particularly global warming, have resulted in widespread calls for the reduction, by regulation and voluntary measures, of the emission greenhouse gases, which include carbon dioxide and methane. These measures could impact the market for our coal and coalbed methane, increase our own energy costs and affect the value of our coal reserves. The United States has not ratified the Framework Convention on Global Climate Change, commonly known as the Kyoto Protocol, which would require our nation to reduce greenhouse gas emissions to 93% of 1990 levels by 2012. The United States is participating in international discussions which are underway to develop a treaty to require additional reductions in greenhouse gas emissions after 2012. The United States has yet to adopt a federal program for controlling greenhouse gas emissions. However, Congress is considering a variety of legislative proposals which would restrict and/or tax the emission of carbon dioxide from the combustion of coal and other fuels and which would mandate or encourage the generation of electricity by new facilities that do not use coal. Even without new legislation, the emission of greenhouse gases may be restricted by future regulation, as the U.S. Supreme Court held in 2007 that the EPA has authority under the Clean Air Act to regulate these gases. The EPA is considering the potential mechanisms for regulating greenhouse gas emissions under the Clean Air Act, including whether to impose restrictions on the emission of carbon dioxide. Federal regulation of the emission of carbon dioxide from coal-fired electric generating stations could adversely affect the demand for coal.

While advocating for comprehensive federal legislation, many states have adopted measures, sometimes as part of a regional collaboration, to reduce green house gases generated within their own jurisdiction. These measures include emission regulations, mandates for utilities to generate a portion of its electricity without using coal and incentives or goals for generating electricity using renewable resources. Some municipalities have also adopted similar measures. Even in the absence of mandatory requirements, some entities are electing to purchase electricity generated by renewable resources for a variety of reasons, including participation in programs calling for voluntary reductions in greenhouse gas emissions.

In addition to impacting our markets, regulations enacted due to climate change concerns could affect our operations by increasing our costs. Our energy costs could increase, and we may have to incur higher costs to control emissions of carbon dioxide, methane or other pollutants from our operations.

Coal Industry Retiree Health Benefit Act of 1992

Unlike many companies in the coal business, we do not have significant liabilities under the Coal Industry Retiree Health Benefit Act of 1992 (the “Coal Act”), which requires the payment of substantial sums to provide lifetime health benefits to union-represented miners (and their dependents) who retired before 1992, because liabilities under the Coal Act that had been imposed on our predecessor or acquired companies were retained by the sellers and, if applicable, their parent companies in the applicable acquisition agreements, except for Anker. We should not be liable for these liabilities retained by the sellers unless they and, if applicable, their parent companies fail to satisfy their obligations with respect to Coal Act claims and retained liabilities covered by the acquisition agreements. Upon the consummation of the business combination with Anker, we assumed Anker’s Coal Act liabilities, which were estimated to be $1.3 million at December 31, 2008.

Endangered Species Act

The federal Endangered Species Act and counterpart state legislation protect species threatened with possible extinction. Protection of threatened and 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 or their habitats. A number of species indigenous to our properties are protected under the Endangered Species Act. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, 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.

Emergency Planning and Community Right to Know Act

Some of our subsidiary operations utilize materials and/or store substances that require certain reporting to local and state authorities under the federal Emergency Planning and Community Right to Know Act. If required reporting is missed it can result in the assessment of fines and penalties. We do not believe that any potential fines or penalties that could potentially arise under the federal Emergency Planning and Community Right to Know Act would materially or adversely affect our ability to mine coal.

Other Regulated Substances

Some of our subsidiary operations utilize certain substances, such as ammonia or caustic soda, for managing water quality in discharges from their mine sites. These materials are considered hazardous and require safeguards in handling and use and, if present in sufficient quantities, create emergency planning and response requirements. The storage of petroleum products in certain quantities can also trigger reporting, planning and response requirements. Our subsidiaries are required to maintain careful control over the storage and use of these substances. The subsidiaries attempt to minimize the amount of materials stored at their operations that give rise to such concerns and to maximize the use of less hazardous materials whenever feasible. If quantities are sufficient, utilization of CCBs for reclamation can trigger certain reporting requirements for constituent trace elements contained in CCBs.

Table of Contents

Additional Information

We file annual, quarterly and current reports, as well as amendments to those reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). You may access and read our SEC filings without charge through our website, www.intlcoal.com, or the SEC's website, www.sec.gov. You may also read and copy any document we file at the SEC's public reference room located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1–800–SEC–0330 for further information on the public reference room. You may also request copies of our filings, at no cost, by telephone at (304) 760-2400 or by mail at: International Coal Group, Inc., 300 Corporate Centre Drive, Scott Depot, West Virginia 25560, Attention: Secretary.

GLOSSARY OF SELECTED TERMS

Ash. Impurities consisting of silica, alumina, calcium, iron 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.

Base load. The lowest level of power production needs during a season or year.

Bituminous coal. A middle rank coal (between sub-bituminous and anthracite) formed by additional pressure and heat on lignite. It is the most common type of coal with moisture content less than 20% by weight and heating value of 10,000 to 14,000 Btus per pound. It is dense and black and often has well-defined bands of bright and dull material. It may be referred to as soft coal.

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). On average, coal contains about 22 million Btu per ton.

By-product. Useful substances made from the gases and liquids left over when coal is changed into coke.

Central Appalachia. Coal producing area in eastern Kentucky, Virginia and southern West Virginia.

Clean coal burning technologies. A number of innovative, new technologies designed to use coal in a more efficient and cost-effective manner while enhancing environmental protection. Several promising technologies include fluidized-bed combustion, integrated gasification combined cycle, limestone injection multi-stage burner, enhanced flue gas desulfurization (or scrubbing), coal liquefaction and coal gasification.

Coal seam. A bed or stratum of coal. Usually applies to a large deposit.

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. Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btu, as required by Phase II of the Clean Air Act Acid Rain program.

Table of Contents

Continuous miner. A machine that simultaneously extracts and loads coal. This is distinguished from a conventional, or cyclic, unit, which must stop the extraction process for loading to commence.

Deep mine. An underground coal mine.

Dragline. A large excavating machine used in the surface mining process to remove overburden (see “Overburden” below). The dragline has a large bucket suspended from the end of a huge boom, which may be 275 feet long or larger. The bucket is suspended by cables and capable of scooping up vast amounts of overburden as it is pulled across the excavation area. The dragline, which can “walk” on huge pontoon-like “feet,” is one of the largest land-based machines in the world.

Fluidized bed combustion. A process with a high success rate in removing sulfur from coal during combustion. Crushed coal and limestone are suspended in the bottom of a boiler by an upward stream of hot air. The coal is burned in this bubbling, liquid-like (or fluidized) mixture. Rather than released as emissions, sulfur from combustion gases combines with the limestone to form a solid compound recovered with the ash.

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

High Btu coal. Coal which has an average heat content of 12,500 Btus per pound or greater.

High sulfur coal. Coal which, when burned, emits 2.5 pounds or more of sulfur dioxide per million Btu.

Highwall. The unexcavated face of exposed overburden and coal in a surface mine or in a face or bank on the uphill side of a contour mine excavation.

Illinois Basin. Coal producing area in Illinois, Indiana and western Kentucky.

Longwall mining. The most productive underground mining method in the United States. One of three main underground coal mining methods currently in use. Employs a rotating drum, or less commonly a steel plow, which is pulled mechanically back and forth across a face of coal that is usually about a thousand feet long. The loosened coal falls onto a conveyor for removal from the mine.

Low sulfur coal. Coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btu.

Medium sulfur coal. Coal which, when burned, emits between 1.6 and 2.5 pounds of sulfur dioxide per million Btu.

Metallurgical coal. The various grades of coal suitable for carbonization to make coke for steel manufacture. Also known as “met” coal, its quality depends on four important criteria: volatile matter, which affects coke yield; the level of impurities including sulfur and ash, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Met coal typically has a particularly high Btu, but low ash and sulfur content.

Nitrogen oxide (NOx). A gas formed in high temperature environments such as coal combustion. It is a harmful pollutant that contributes to acid rain.

Non-reserve coal deposits. Non-reserve coal deposits are coal bearing bodies that have been sufficiently sampled and analyzed, but do not qualify as a commercially viable coal reserve as prescribed by SEC rules until a final comprehensive SEC prescribed evaluation is performed.

Northern Appalachia. Coal producing area in Maryland, Ohio, Pennsylvania and northern West Virginia.

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

Table of Contents

Pillar. An area of coal left to support the overlying strata in a mine; sometimes left permanently to support surface structures.

Powder River Basin. Coal producing area in northeastern Wyoming and southeastern Montana. This is the largest known source of coal reserves and the largest producing region in the United States.

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

Probable reserves. Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven 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 reserves, is high enough to assume continuity between points of observation.

Reclamation. The process of restoring land and environmental values to a mining site after the coal is extracted. Reclamation operations are usually underway where the resources have already been taken from a mine, even as production operations are taking place elsewhere at the site. This process commonly includes recontouring or reshaping the land to its approximate original appearance, restoring topsoil and planting native grasses, trees and ground covers. Mining reclamation is closely regulated by both state and federal law.

Recoverable reserve. The amount of coal that can be recovered from the Reserves. The recovery factor for underground mines is approximately 60% and for surface mines approximately 80% to 90%. Using these percentages, there are about 275 billion tons of recoverable reserves in the United States.

Reserve. That part of a mineral deposit that could be economically and legally extracted or produced at the time of the reserve determination.

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

Room-and-pillar mining. A method of underground mining in which about half of the coal is left in place to support the roof of the active mining area. Large "pillars" are left at regular intervals while "rooms" of coal are extracted.

Scrubber (flue gas desulfurization system). Any of several forms of chemical/physical devices which operate to neutralize sulfur compounds 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 approximately 6% to 7% of a power plant's electrical output and thousands of gallons of water to operate.

Steam coal. Coal used by electric power plants and industrial steam boilers to produce electricity, steam or both. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Sub-bituminous coal. Dull coal that ranks between lignite and bituminous coal. Its moisture content is between 20% and 30% by weight, and its heat content ranges from 7,800 to 9,500 Btus per pound of coal.

Sulfur. One of the elements present in varying quantities in coal that contributes to environmental degradation when coal is burned. Sulfur dioxide is produced as a gaseous by-product of coal combustion.

Tons. A “short” or net ton is equal to 2,000 pounds. A “long” or British ton is equal to 2,240 pounds. A “metric” ton is approximately 2,205 pounds. The short ton is the unit of measure referred to in this report.

Truck-and-shovel/loader mining. Similar forms of mining where large shovels or front-end loaders are used to remove overburden, which is used to backfill pits after the coal is removed. Smaller shovels load coal in haul trucks for transportation to the preparation plant or rail loadout.

Underground mine. Also known as a deep mine. Usually located several hundred feet below the earth’s surface, an underground mine’s resource is removed mechanically and transferred by conveyor to the surface. Most common in the coal industry, underground mines primarily are located east of the Mississippi River and account for approximately one-third of total annual U.S. coal production.

Table of Contents

ITEM 1A. RISK FACTORS

Risks Relating To Our Business

A decline in coal prices could reduce our revenues and the value of our coal reserves.

Our results of operations are dependent upon the prices we receive for our coal, as well as our ability to improve productivity and control costs. Any decreased demand would cause spot prices to decline and require us to increase productivity and decrease costs in order to maintain our margins. During the first half of 2008, the spot market prices increased leading to a higher average price per ton of coal. A decrease in those prices in 2009 could adversely affect our operating results and our ability to generate the cash flows we require to meet our bank loan requirements, improve our productivity and invest in our operations. The prices we receive for coal depend upon factors beyond our control, including:

- supply of and demand for domestic and foreign coal;
- demand for electricity;
- domestic and foreign demand for steel and the continued financial viability of the domestic and/or foreign steel industry;
- proximity to, capacity of and cost of transportation facilities;
- domestic and foreign governmental regulations and taxes;
- air emission standards for coal-fired power plants;
- regulatory, administrative and judicial decisions;
- price and availability of alternative fuels, including the effects of technological developments; and
- effect of worldwide energy conservation measures.

Our coal mining operations are subject to operating risks that could result in decreased coal production, which could reduce our revenues.

Our revenues depend on our level of coal mining production. The level of our production is subject to operating conditions and events beyond our control that could disrupt operations and affect production at particular mines for varying lengths of time. These conditions and events include:

- unavailability of qualified labor;
- our inability to acquire, maintain or renew necessary permits or mining or surface rights in a timely manner, if at all;
- unfavorable geologic conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposits;

- failure of reserve estimates to prove correct;
- changes in governmental regulation of the coal industry, including the imposition of additional taxes, fees or actions to suspend or revoke our permits or changes in the manner of enforcement of existing regulations;
- mining and processing equipment failures and unexpected maintenance problems;
- adverse weather and natural disasters, such as heavy rains and flooding;
- increased water entering mining areas and increased or accidental mine water discharges;
- increased or unexpected reclamation costs;
- interruptions due to transportation delays;
- unavailability of required equipment of the type and size needed to meet production expectations; and
- unexpected mine safety accidents, including fires and explosions.

These conditions and events may increase our cost of mining and delay or halt production at particular mines either permanently or for varying lengths of time. We were impacted during 2008 by a tightening labor market increasing our compensation costs, as well as increases in costs for repairs and maintenance, diesel fuel, blasting supplies, roof control supplies and contract labor, all of which increased the cost of coal sales.

Table of Contents

Reduced coal consumption by North American electric power generators could result in lower prices for our coal, which could reduce our revenues and adversely impact our earnings and the value of our coal reserves.

Steam coal accounted for 94% of all our coal sales volume in 2008 and the majority of our sales of steam coal in 2008 were to electric power generators. Domestic electric power generation accounted for approximately 93% of all U.S. coal consumption in 2007, according to the EIA. The amount of coal consumed for U.S. electric power generation is affected primarily by the overall demand for electricity, the location, availability, quality and price of competing fuels for power such as natural gas, nuclear, fuel oil and alternative energy sources such as hydroelectric power, technological developments and environmental and other governmental regulations.

Although we expect that new power plants will be built to produce electricity during peak periods of demand, we also expect that many of these new power plants will be fired by natural gas because gas-fired plants are cheaper to construct than coal-fired plants and because natural gas is a cleaner burning fuel. Gas-fired generation from existing and newly constructed gas-fired facilities has the potential to displace coal-fired generation, particularly from older, less efficient coal-powered generators. In addition, the increasingly stringent requirements of the Clean Air Act and the potential regulation of greenhouse gas emissions may result in more electric power generators shifting from coal to natural gas-fired plants or alternative energy sources. Furthermore, environmental activists have evidenced an intent to use regulatory and judicial processes to block the construction of any new coal-fired power plants or capacity expansions to existing plants due to climate change concerns, at least until carbon dioxide emissions controls for such plants are imposed by federal law. Any reduction in the amount of coal consumed by North American electric power generators could reduce the price of steam coal that we mine and sell, thereby reducing our revenues and adversely impacting our earnings and the value of our coal reserves.

Weather patterns also can greatly affect electricity generation. Extreme temperatures, both hot and cold, cause increased power usage and, therefore, increased generating requirements from all sources. Mild temperatures, on the other hand, result in lower electrical demand, which allows generators to choose the lowest-cost sources of power generation when deciding which generation sources to dispatch. Accordingly, significant changes in weather patterns could reduce the demand for our coal.

Overall economic activity and the associated demands for power by industrial users can have significant effects on overall electricity demand. Robust economic activity can cause much heavier demands for power, particularly if such activity results in increased utilization of industrial assets during evening and nighttime periods. An economic slowdown can significantly slow the growth of electrical demand and, in some locations, result in contraction of demand. The economy suffered a significant slowdown in the fourth quarter of 2008 that resulted in lower demand. Any downward pressure on coal prices, whether due to increased use of alternative energy sources, changes in weather patterns, decreases in overall demand or otherwise, would likely cause our profitability to decline.

Table of Contents

The capability and profitability of our operations may be adversely affected by the status of our long-term coal supply agreements and changes in purchasing patterns in the coal industry.

We sell a significant portion of our coal under long-term coal supply agreements, which we define as contracts with a term greater than 12 months. For the year ended December 31, 2008, approximately 51% of our revenues were derived from coal sales that were made under long-term coal supply agreements. As of that date, we had 49 long-term sales agreements with a volume-weighted average term of approximately 3.8 years. The prices for coal shipped under these agreements are typically fixed for at least the initial year of the contract, subject to certain adjustments in later years and thus may be below the current market price for similar type coal at any given time, depending on the timeframe of contract execution or initiation. 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 higher coal prices, if and when they arise. In addition, in some cases, 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 allowable under some contracts. When our current contracts with customers expire or are otherwise renegotiated, our customers may decide not to extend or enter into new long-term contracts or, in the absence of long-term contracts, our customers may decide to purchase fewer tons of coal than in the past or on different terms, including under different pricing terms.

Furthermore, as electric utilities seek to adjust to requirements of the Clean Air Act, and the potential for more stringent requirements, they could become increasingly less willing to enter into long-term coal supply agreements and instead may purchase higher percentages of coal under short-term supply agreements. To the extent the electric utility industry shifts away from long-term supply agreements, it could adversely affect us and the level of our revenues. For example, fewer electric utilities will have a contractual obligation to purchase coal from us, thereby increasing the risk that we will not have a market for our production. Furthermore, spot market prices tend to be more volatile than contractual prices, which could result in decreased revenues.

Certain provisions in our long-term supply agreements may provide limited protection during periods of adverse economic conditions. For example, the customer may be forced to reduce electricity output due to weak demand. If the low demand were to persist for an extended period the customer might be forced to delay our contract shipments thereby reducing our revenue.

Price adjustment, “price reopener” and other similar provisions in long-term supply agreements may reduce the protection from short-term coal price volatility traditionally provided by such contracts. Most of our coal supply agreements contain provisions that allow for the purchase price to be renegotiated at periodic intervals. These price reopener provisions may automatically set a new price based on the prevailing market price or, in some instances, require the parties to agree on a new price, sometimes between a specified range of prices. In some circumstances, failure of the parties to agree on a price under a price reopener provision can lead to termination of the contract. Any adjustment or renegotiations leading to a significantly lower contract price would result in decreased revenues. Accordingly, supply contracts with terms of one year or more may provide only limited protection during adverse market conditions.

Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or our customers during the duration of specified events beyond the control of the affected party. Additionally, most of our coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as heat value (measured in Btus), sulfur content, ash content, hardness and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or, in the extreme, termination of the contracts.

Consequently, due to the risks mentioned above, we may not achieve the revenue or profit we expect to achieve from our long-term supply agreements.

The duration or severity of the current global financial crisis are uncertain and may have an impact on our business and financial conditions in ways that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may impact our business and our financial condition. In light of the current economic condition in the financial markets, there can be no assurance the lenders participating in our credit facility will fulfill their commitments in accordance with their legal obligations under the credit facility. If one or more of the lenders were to default on its obligation to fund its commitment, the portion of the credit facility provided by such defaulting lender would not be available to us. We also have access to a revolving credit facility to purchase equipment from one of our vendors. The ability of the vendor to provide this financing in the future may be negatively impacted by the current credit crisis. Our ability to obtain alternate financing on acceptable terms (if at all) may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet capital commitments.

Additionally, while we have committed and priced the vast majority of our planned shipments of coal production for next year, 26%, or approximately 434,000 tons, of our uncommitted tonnage for 2009 is metallurgical coal. Visibility into the domestic and international metallurgical coal markets is difficult because of recently announced price and production cuts by steel producers in several countries, including the U.S. The depth and duration of this imminent slowdown in the steel sector has yet to be defined and a reduction in global steel production could adversely impact overall demand for, and/or result in deferrals of or refusal to receive shipments of, our metallurgical coal, which could have a negative effect on our revenues.

Table of Contents

A decline in demand for metallurgical coal would limit our ability to sell our high quality steam coal as higher-priced metallurgical coal.

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 metallurgical and steam coal markets. 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, thereby reducing our revenues and profitability. However, some of our mines operate profitably only if all or a portion of their production is sold as metallurgical coal to the steel market. If demand for metallurgical coal declined to the point where we could earn a more attractive return marketing the coal as steam coal, these mines may not be economically viable and may be subject to closure. Such closures would lead to accelerated reclamation costs, as well as reduced revenue and profitability.

Inaccuracies in our estimates of economically recoverable coal reserves could result in lower than expected revenues, higher than expected costs or decreased profitability.

We base our reserves information on engineering, economic and geological data assembled and analyzed by our staff, which includes various engineers and geologists, and which is periodically reviewed by outside firms. The reserves estimates as to both quantity and quality are annually updated to reflect production of coal from the reserves, acquisitions, dispositions, depleted reserves and new drilling or other data received. There are numerous uncertainties inherent in estimating quantities and qualities of and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves and net cash flows necessarily depend upon a number of variable factors and assumptions, all of which may vary considerably from actual results such as:

- geological and mining conditions which may not be fully identified by available exploration data or which may differ from experience in current operations;

- historical production from the area compared with production from other similar producing areas; and

- assumed effects of regulation and taxes by governmental agencies and assumptions concerning coal prices, operating costs, mining technology improvements, severance and excise taxes, development costs and reclamation costs.

For these reasons, estimates of the economically recoverable quantities and qualities attributable to any particular group of properties, classifications of reserves based on risk of recovery and estimates of net cash flows expected from particular reserves prepared by different engineers or by the same engineers at different times may vary substantially. Actual coal tonnage recovered from identified reserve areas or properties, and revenues and expenditures with respect to our reserves, may vary materially from estimates. These estimates, thus, may not accurately reflect our actual reserves. Any inaccuracy in our estimates related to our reserves could result in lower than expected revenues, higher than expected costs or decreased profitability.

Table of Contents

We depend heavily on a small number of large customers, the loss of any of which would adversely affect our operating results.

Our three largest customers for the year ended December 31, 2008 were Progress Energy, Georgia Power Company and Allegheny Energy Supply Company and we derived approximately 32% of our coal revenues from sales to our five largest customers. At December 31, 2008, we had coal supply agreements with these customers that expire at various times from 2009 to 2011. We typically discuss extension of existing agreements or entering into long-term agreements with our customers, however these negotiations may not be successful and these customers may not continue to purchase coal from us pursuant to long-term coal supply agreements. If a number of these customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer materially.

Disruptions in transportation services could limit our ability to deliver coal to our customers, which could cause revenues to decline.

We depend primarily upon railroads, trucks and barges to deliver coal to our customers. Disruption of railroad service due to weather-related problems, strikes, lockouts and other events could temporarily impair our ability to supply coal to our customers, resulting in decreased shipments and related sales revenues. Decreased performance levels over longer periods of time could cause our customers to look elsewhere for their fuel needs, negatively affecting our revenues and profitability.

Several of our mines depend on a single transportation carrier or a single mode of transportation. Disruption of any of these transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks and other events could temporarily impair our ability to supply coal to our customers. Our transportation providers may face difficulties in the future that may impair our ability to supply coal to our customers, resulting in decreased revenues.

If there are disruptions of the transportation services provided by our primary rail carriers that transport our produced coal and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

Fluctuations in transportation costs could impair our ability to supply coal to our customers.

Transportation costs represent a significant portion of the total cost of coal for our customers and, as a result, the cost of transportation is a critical factor in a customer’s purchasing decision. Increases in transportation costs could make coal a less competitive source of energy or could make our coal production less competitive than coal produced from other sources.

Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country. For instance, coordination of the many eastern loading facilities, the large number of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make shipments originating in the eastern United States inherently more expensive on a per-mile basis than shipments originating in the western United States. The increased competition could have a material adverse effect on our business, financial condition and results of operations.

Table of Contents

Disruption in supplies of coal produced by third parties could temporarily impair our ability to fill our customers' orders or increase our costs.

In addition to marketing coal that is produced from our controlled reserves, we purchase and resell coal produced by third parties from their controlled reserves to meet customer specifications. Disruption in our supply of third-party coal could temporarily impair our ability to fill our customers' orders or require us to pay higher prices in order to obtain the required coal from other sources. Any increase in the prices we pay for third-party coal could increase our costs and, therefore, lower our earnings.

The unavailability of an adequate supply of coal reserves that can be mined at competitive costs could cause our profitability to decline.

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Because our reserves decline as we mine our coal, our future success and growth depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. 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. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

Unexpected increases in raw material costs or decreases in availability could significantly impair our operating profitability.

Our coal mining operations use significant amounts of steel, rubber, petroleum products and other raw materials in various pieces of mining equipment, supplies and materials, including the roof bolts required by the room-and-pillar method of mining described previously. Scrap steel prices have risen significantly and, historically, the prices of scrap steel and petroleum have fluctuated. In 2008, we were adversely impacted by margin compressions due to cost increases for various commodities and services such as diesel fuel, explosives (ANFO), roof control supplies and coal trucking, influenced by the price variability of crude oil and natural gas. There may be other acts of nature, terrorist attacks or threats or other conditions that could also increase the costs of raw materials. If the price of steel, rubber, petroleum products or other of these materials increase, our operational expenses will increase, which could have a significant negative impact on our profitability. Additionally, shortages in raw materials used in the manufacturing of supplies and mining equipment could limit our ability to obtain such items which could have an adverse effect on our ability to carry out our business plan.

The accident at the Sago mine could negatively impact our business.

On January 2, 2006, an explosion occurred at our Sago mine in West Virginia, which will be sealed and permanently closed in 2009. The explosion tragically resulted in the deaths of twelve miners and the critical injury of another miner. As a result of the accident, the federal and state investigations and related matters and civil litigation arising out of the accident, our business may be negatively impacted by various factors including the diversion of management's attention from our day-to-day business, further negative media attention, any negative perceptions about our safety record affecting our ability to attract skilled labor, the impact of litigation commenced against us, any increased premiums for insurance and any claims that may be asserted against us that are not covered, in whole or in part, by our

insurance policies.

Table of Contents

A shortage of skilled labor in the mining industry could pose a risk to achieving optimal labor productivity and competitive costs, which could adversely affect our profitability.

Efficient coal mining using modern techniques and equipment requires skilled laborers, preferably with at least a year of experience and proficiency in multiple mining tasks. In order to support our planned expansion opportunities, we intend to sponsor both in-house and vocational coal mining programs at the local level in order to train additional skilled laborers. Labor and benefit costs have increased in 2008 due to a tightening labor market resulting in the need to offer more competitive compensation packages. Contract labor costs also increased over prior year. In 2008, $12.68 and $1.60 of our cost of coal sales per ton were attributable to labor and benefits and contract labor, respectively, compared to $10.60 and $1.11 for 2007. In the event the shortage of experienced labor continues or worsens or we are unable to train the necessary amount of skilled laborers, there could be an adverse impact on our labor productivity and costs and our ability to expand production and therefore have a material adverse effect on our earnings.

Our ability to operate our company effectively could be impaired if we fail to attract and retain key personnel.

Our senior management team averages 24 years of experience in the coal industry, which includes developing innovative, low-cost mining operations, maintaining strong customer relationships and making strategic, opportunistic acquisitions. The loss of any of our senior executives could have a material adverse effect on our business. There may be a limited number of persons with the requisite experience and skills to serve in our senior management positions. We may not be able to locate or employ qualified executives on acceptable terms. In addition, as our business develops and expands, we believe that our future success will depend greatly on our continued ability to attract and retain highly skilled personnel with coal industry experience. Competition for these persons in the coal industry is intense and we may not be able to successfully recruit, train or retain qualified personnel. We may not be able to continue to employ key personnel or attract and retain qualified personnel in the future. Our failure to retain or attract key personnel could have a material adverse effect on our ability to effectively operate our business.

Acquisitions that we may undertake involve a number of inherent risks, any of which could cause us not to realize the anticipated benefits.

We continually seek to expand our operations and coal reserves through selective acquisitions. If we are unable to successfully integrate the companies, businesses or properties we acquire, our profitability may decline and we could experience a material adverse effect on our business, financial condition or results of operations. Acquisition transactions involve various inherent risks, including:

- uncertainties in assessing the value, strengths and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental or mine safety liabilities) of, acquisition candidates;
- potential loss of key customers, management and employees of an acquired business;
- ability to achieve identified operating and financial synergies anticipated to result from an acquisition;
- discrepancies between the estimated and actual reserves of the acquired business;
- problems that could arise from the integration of the acquired business; and
-

unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the acquisition.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from an acquisition. Any acquisition opportunities we pursue could materially affect our liquidity and capital resources and may require us to incur indebtedness, seek equity capital or both. In addition, future acquisitions could result in our assuming more long-term liabilities relative to the value of the acquired assets than we have assumed in our previous acquisitions.

Table of Contents

Risks inherent to mining could increase the cost of operating our business.

Our mining operations are subject to conditions that can impact the safety of our workforce or delay coal deliveries or increase the cost of mining at particular mines for varying lengths of time. These conditions include fires and explosions from methane gas or coal dust; accidental minewater discharges; weather, flooding and natural disasters; unexpected maintenance problems; key equipment failures; variations in coal seam thickness; variations in the amount of rock and soil overlying the coal deposit; variations in rock and other natural materials and variations in geologic conditions. We maintain insurance policies that provide limited coverage for some of these risks, although there can be no assurance that these risks would be fully covered by our insurance policies. Despite our efforts, significant mine accidents could occur and have a substantial impact. See "– The accident at the Sago mine could negatively impact our business."

Inability of contract miner or brokerage sources to fulfill the delivery terms of their contracts with us could reduce our profitability.

In conducting our mining operations, we utilize third-party sources of coal production, including contract miners and brokerage sources, to fulfill deliveries under our coal supply agreements. Our profitability or exposure to loss on transactions or relationships such as these is dependent upon the reliability (including financial viability) and price of the third-party supply, our obligation to supply coal to customers in the event that adverse geologic mining conditions restrict deliveries from our suppliers, our willingness to participate in temporary cost increases experienced by our third-party coal suppliers, our ability to pass on temporary cost increases to our customers, the ability to substitute, when economical, third-party coal sources with internal production or coal purchased in the market and other factors. Brokerage sources and contract miners may experience adverse geologic mining and/or financial difficulties that make their delivery of coal to us at the contractual price difficult or uncertain. If we have difficulty with our third-party sources of coal, our profitability could decrease.

Table of Contents

We may be unable to generate sufficient taxable income from future operations to fully utilize our significant tax net operating loss carryforwards or maintain our deferred tax assets.

As a result of our acquisition of Anker and of historical financial results, we have recorded deferred tax assets. If we fail to generate profits in the foreseeable future, our deferred tax assets may not be fully utilized. We evaluate our ability to utilize our net operating loss ("NOL") and tax credit carryforwards each period and, in compliance with SFAS No. 109, Accounting for Income Taxes ("SFAS 109"), record any resulting adjustments that may be required to deferred income tax expense. In addition, we will reduce the deferred income tax asset for the benefits of NOL and tax credit carryforwards used in future periods and will recognize and record federal and state income tax expense at statutory rates in future periods. If, in the future, we determine that it is more likely than not that we will not realize all or a portion of the deferred tax assets, we will record a valuation allowance against deferred tax assets which would result in a charge to income tax expense.

Failure to obtain or renew surety bonds in a timely manner and on acceptable terms could affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease coal.

Federal and state laws require us to obtain surety bonds to secure payment of certain long-term obligations, such as mine closure or reclamation costs, federal and state workers' compensation costs. Certain business transactions, such as coal leases and other obligations, may also require bonding. These bonds are typically renewable annually. Surety bond issuers and holders may not continue to renew the bonds or may demand additional collateral or other less favorable terms upon those renewals. The ability of surety bond issuers and holders to demand additional collateral or other less favorable terms has increased as the number of companies willing to issue these bonds has decreased over time. Our failure to maintain, or our inability to acquire, surety bonds that are required by state and federal law would affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease coal. That failure could result from a variety of factors including, without limitation:

- lack of availability, higher expense or unfavorable market terms of new bonds;
- restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our amended and restated credit facility; and
- exercise by third-party surety bond issuers of their right to refuse to renew the surety.

Failure to maintain capacity for required letters of credit could limit our ability to obtain or renew surety bonds.

At December 31, 2008, we had $73.6 million of letters of credit in place, of which $61.1 million serves as collateral for reclamation surety bonds and $12.5 million secures miscellaneous obligations. Our amended and restated credit facility provides for a revolving credit facility of $100.0 million, of which up to $80.0 million may be used for letters of credit. If we do not maintain sufficient borrowing capacity under our amended and restated credit facility for additional letters of credit, we may be unable to obtain or renew surety bonds required for our mining operations.

Our business may require continued capital investment, which we may be unable to provide.

Our business strategy may require continued capital investment. We require capital for, among other purposes, managing acquired assets, acquiring new equipment, maintaining the condition of our existing equipment and maintaining compliance with environmental laws and regulations. To the extent that cash generated internally and cash available under our credit facilities are not sufficient to fund capital requirements, we will require additional debt and/or equity financing. However, this type of financing may not be available, particularly in current market

conditions, or if available, may not be on satisfactory terms. Future debt financings, if available, may result in increased interest and amortization expense, increased leverage and decreased income available to fund further acquisitions and expansion. In addition, future debt financings may limit our ability to withstand competitive pressures and render us more vulnerable to economic downturns. If we fail to generate sufficient earnings or to obtain sufficient additional capital in the future or fail to manage our capital investments effectively, we could be forced to reduce or delay capital expenditures, sell assets or restructure or refinance our indebtedness.

In addition, the credit agreement governing our amended and restated credit facility contains customary affirmative and negative covenants for credit facilities of this type, including, but not limited to, limitations on the incurrence of indebtedness, asset dispositions, acquisitions, investments, dividends and other restricted payments, liens and transactions with affiliates. The credit agreement requires us to meet certain financial tests, including a maximum leverage ratio, a minimum interest coverage ratio, and a limit on capital expenditures. If we fail to comply with any affirmative or negative covenant, or to meet any financial test, in our credit agreement, we may be unable to obtain or renew surety bonds required for our mining operations.

The credit agreement also contains customary events of default, including, but not limited to, failure to pay principal or interest, breach of covenants or representations and warranties, cross-default to other indebtedness, judgment default and insolvency. If an event of default occurs under the credit agreement, the lenders under the credit agreement will be entitled to take various actions, including demanding payment for all amounts outstanding thereunder and foreclosing on any collateral. If the lenders were to do so, our other debt obligations including the senior notes and the convertible notes, would also have the right to accelerate those obligations which the Company would be unable to satisfy. See “– Our ability and the ability of some of our subsidiaries to engage in some business transactions or to pursue our business strategy may be limited by the terms of our existing debt” and “– The duration or severity of the current global financial crisis are uncertain and may have an impact on our business and financial conditions in ways that we currently cannot predict.”

Table of Contents

Increased consolidation and competition in the U.S. coal industry may adversely affect our ability to retain or attract customers and may reduce domestic coal prices.

During the last several years, the U.S. coal industry has experienced increased consolidation, which has contributed to the industry becoming more competitive. According to the EIA, in 1995, the top ten coal producers accounted for approximately 50% of total domestic coal production. By 2007, however, the top ten coal producers' share had increased to approximately 65% of total domestic coal production. Consequently, many of our competitors in the domestic coal industry are major coal producers who have significantly greater financial resources than us. The intense competition among coal producers may impact our ability to retain or attract customers and may therefore adversely affect our future revenues and profitability.

The demand for U.S. coal exports is dependent upon a number of factors outside of our control, including the overall demand for electricity in foreign markets, currency exchange rates, ocean freight rates, the demand for foreign-produced steel both in foreign markets and in the U.S. market (which is dependent in part on tariff rates on steel), general economic conditions in foreign countries, technological developments and environmental and other governmental regulations. If foreign demand for U.S. coal were to decline, this decline could cause competition among coal producers in the United States to intensify, potentially resulting in additional downward pressure on domestic coal prices.

Our ability to collect payments from our customers could be impaired if their creditworthiness deteriorates.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. Our customer base is changing with deregulation as utilities sell their power plants to their non-regulated affiliates or third parties that may be less creditworthy, thereby increasing the risk we bear on payment default. These new power plant owners may have credit ratings that are below investment grade. In addition, a recent slowdown in the global steel sector has resulted in announced price and production cuts by steel producers in several countries, which could impact the ability of our metallurgical coal customers to settle outstanding amounts due to us. Further, competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk we bear on payment default.

We have contracts to supply coal to energy trading and brokering companies under which those companies sell coal to end users. In recent years, the creditworthiness of the energy trading and brokering companies with which we do business declined, increasing the risk that we may not be able to collect payment for all coal sold and delivered to or on behalf of these energy trading and brokering companies.

In the current economic climate certain of our customers and their customers may be affected by cash flow problems, which has the potential to increase the time it takes to collect accounts receivables.

Defects in title or loss of any leasehold interests in our properties could limit our ability to conduct mining operations on these properties or result in significant unanticipated costs.

We conduct a significant part of our mining operations on properties that we lease. A title defect or the loss of any lease upon expiration of its term, upon a default or otherwise, could adversely affect our ability to mine the associated reserves and/or process the coal that we mine. Title to most of our owned or leased properties and mineral rights is not usually verified until we make a commitment to develop a property, which may not occur until after we have obtained necessary permits and completed exploration of the property. In some cases, we rely on title information or representations and warranties provided by our lessors or grantors. Our right to mine some of our reserves has in the past been, and may again in the future be, adversely affected if defects in title or boundaries exist or if a lease expires.

Any challenge to our title or leasehold interests could delay the exploration and development of the property and could ultimately result in the loss of some or all of our interest in the property. Mining operations from time to time may rely on an expired lease that we are unable to renew. From time to time we also may be in default with respect to leases for properties on which we have mining operations. In such events, we may have to close down or significantly alter the sequence of such mining operations which may adversely affect our future coal production and future revenues. If we mine on property that we do not own or lease, we could incur liability for such mining. Also, in any such case, the investigation and resolution of title issues would divert management's time from our business and our results of operations could be adversely affected. Additionally, if we lose any leasehold interests relating to any of our preparation plants, we may need to find an alternative location to process our coal and load it for delivery to customers, which could result in significant unanticipated costs.

In order to obtain leases or mining contracts to conduct our mining operations on property where these defects exist, we may in the future have to incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases or mining contracts 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. Some leases have minimum production requirements. Failure to meet those requirements could result in losses of prepaid royalties and, in some rare cases, could result in a loss of the lease itself.

Table of Contents

Our work force could become unionized in the future, which could adversely affect the stability of our production and reduce our profitability.

All of our coal production is from mines operated by union-free employees. However, our subsidiaries' employees have the right at any time under the National Labor Relations Act to form or affiliate with a union. If the terms of a union collective bargaining agreement are significantly different from our current compensation arrangements with our employees, any unionization of our subsidiaries' employees could adversely affect the stability of our production and reduce our profitability.

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

During the mid-1970s and early 1980s, a growing coal market and increased demand for coal attracted new investors to the coal industry, spurred the development of new mines and resulted in production capacity in excess of market demand throughout the industry. Similarly, increases in future coal prices could encourage the development of expanded capacity by new or existing coal producers.

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

We are parties to a number of legal proceedings incidental to normal business activities, including several complaints related to the accident at our Sago mine, a breach of contract complaint by one of our customers related to the idling of our Sycamore No. 2 mine and class action lawsuits that allege that the registration statements filed in connection with our initial public offering contained false and misleading statements, and that investors relied upon those securities filings and suffered damages as a result. Some actions brought against us from time to time may have merit. There is always the potential that an individual matter or the aggregation of many matters could have an adverse effect on our financial condition, results of operations or cash flows. See "Legal Proceedings" contained in Item 3 of this Annual Report on Form 10-K.

Because of our limited operating history, historical information regarding our company prior to October 1, 2004 is of little relevance in understanding our business as currently conducted.

We were incorporated in March 2005 as a holding company and ICG, Inc. was incorporated in May 2004 for the sole purpose of acquiring certain assets of Horizon. Until the completion of the Horizon asset acquisition, we had substantially no operations. As a result, historical information regarding our company prior to October 1, 2004, which does not include the historical financial information for Anker and CoalQuest, is of limited relevance in understanding our business as currently conducted. The financial statements for the Horizon predecessor periods have been prepared from the books and records of Horizon as if we had existed as a separate legal entity under common management for all periods presented (that is, on a "carve-out" basis). The financial statements for the Horizon predecessor periods include allocations of certain expenses, taxation charges, interest and cash balances relating to the predecessor based on management's estimates. In light of these allocations and estimates, the Horizon predecessor financial information is not necessarily indicative of our consolidated financial position, results of operations and cash flows if we had operated during the Horizon predecessor period presented. See "Selected Financial Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Risks Relating To Government Regulation

Extensive government regulations impose significant costs on our mining operations, and future regulations could increase those costs or limit our ability to produce and sell coal.

The coal mining industry is subject to increasingly strict regulation by federal, state and local authorities with respect to matters such as:

- limitations on land use;
- employee health and safety;
- mandated benefits for retired coal miners;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- air quality standards;
- water pollution;
- construction and permitting of facilities required for mining operations, including valley fills and other structures, including those constructed in waterbodies and wetlands;
- protection of human health, plantlife and wildlife;
- discharge of materials into the environment;
- surface subsidence from underground mining; and
- effects of mining on groundwater quality and availability.

Table of Contents

In particular, federal and state statutes require us to restore mine property in accordance with specific standards and an approved reclamation plan, and require that we obtain and periodically renew permits for mining operations. If we do not make adequate provisions for all expected reclamation and other costs associated with mine closures, it could harm our future operating results.

Federal and state safety and health regulation in the coal mining industry may be the most comprehensive and pervasive system for protection of employee safety and health affecting any segment of the U.S. industry. It is costly and time-consuming to comply with these requirements and new regulations or orders may materially adversely affect our mining operations or cost structure, any of which could harm our future results.

Under federal law, each coal mine operator must secure payment of federal black lung benefits to claimants who are current and former employees and contribute to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry before July 1973. The trust fund is funded by an excise tax on coal production. If this tax increases, or if we could no longer pass it on to the purchaser of our coal under many of our long-term sales contracts, it could increase our operating costs and harm our results. New regulations that took effect in 2001 could significantly increase our costs related to contesting and paying black lung claims. If new laws or regulations increase the number and award size of claims, it could substantially harm our business.

The costs, liabilities and requirements associated with these and other regulations may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. Failure to comply with these 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. We may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. We must compensate employees for work-related injuries. If we do not make adequate provisions for our workers' compensation liabilities, it could harm our future operating results. If we are pursued for these sanctions, costs and liabilities, our mining operations and, as a result, our profitability could be adversely affected. See "Environmental, Safety and Other Regulatory Matters."

The possibility exists that new legislation and/or regulations and orders may be adopted that may materially adversely affect our mining operations, our cost structure and/or our customers' ability to use coal. New legislation or administrative regulations (or new judicial interpretations or administrative enforcement of existing laws and regulations), including proposals related to the protection of the environment that would further regulate and tax the coal industry, may also require us or our customers to change operations significantly or incur increased costs. These regulations, if proposed and enacted in the future, could have a material adverse effect on our financial condition and results of operations.

Judicial rulings that restrict disposal of mining spoil material could significantly increase our operating costs, discourage customers from purchasing our coal and materially harm our financial condition and operating results.

Mining in the mountainous terrain of Appalachia typically requires the use of valley fills for the disposal of excess spoil (rock and soil material) generated by construction and mining activities. In our surface mining operations, we use mountaintop removal mining wherever feasible because it allows us to recover more tons of coal per acre and facilitates the permitting of larger projects, which allows mining to continue over a longer period of time than would be the case using other mining methods. Mountaintop removal mining, along with other methods of surface mining, depends on valley fills to dispose of mining spoil material. Construction of roads, underground mine portal sites, coal processing and handling facilities and coal refuse embankments or impoundments also require the development of valley fills. We obtain permits to construct and operate valley fills and surface impoundments from the Army Corps of

Engineers (the "ACOE") under the auspices of Section 404 of the federal Clean Water Act. Lawsuits challenging the ACOE's authority to authorize surface mining activities under Nationwide Permit 21 or under more comprehensive individual permits have been instituted by environmental groups, which also advocate for changes in federal and state laws that would prevent or further restrict the issuance of such permits. The Fourth Circuit Court of Appeals in 2005 vacated and remanded one such suit that was originally filed in West Virginia, concluding that the ACOE complied with the Clean Water Act when it promulgated the 2002 version of Nationwide Permit 21. Final disposition of that case is pending before Judge Joseph R. Goodwin of the U.S. District Court for the Southern District of West Virginia. A similar lawsuit filed in federal court in Kentucky is still pending. Both of those cases had additional briefing by the parties in 2008 and are awaiting decision or further direction from the courts.

In a March 2007 decision pertaining originally to certain Section 404 permits issued to Massey Energy Company, Judge Robert C. Chambers of the U.S. District Court for the Southern District of West Virginia ruled that the ACOE failed to adequately assess the impacts of surface mining on headwaters and approved mitigation that did not appropriately compensate for stream losses. Judge Chambers in June 2007 found that sediment ponds situated within a stream channel violated the prohibition against using the waters of the U.S. for waste treatment and further decided that using the reach of stream between a valley fill and the sediment pond to transport sediment-laden runoff is prohibited by the Clean Water Act. The ACOE along with several intervenors appealed Judge Chambers' decisions to the Fourth Circuit Court of Appeals, which heard oral arguments in September 2008. A three judge panel of the Fourth Circuit on February 13, 2009 reversed, vacated and remanded Judge Chambers' March 2007 and June 2007 decisions in their entirety, ruling that the ACOE properly exercised its discretion in the permit review and approval process. The appellees have not publicly stated their intentions with respect to further appeals.

A similar challenge to the ACOE Section 404 permit process was launched by environmental groups in Kentucky in December 2007 when a lawsuit was filed in federal court against the ACOE alleging that it wrongfully issued a Section 404 authorization for the expansion of ICG Hazard's Thunder Ridge surface mine. That permit was suspended on December 26, 2007 to allow the ACOE to review the documentation on which the permit decision was based. Subsequently, the AOCE requested supplemental information from ICG Hazard, which has been provided. All court proceedings are on hold in this case while the ACOE considers its decision. The Company currently has two subsidiaries in that jurisdiction of Kentucky that will require Section 404 permits within the next two years. If permitting requirements are substantially increased or if mining methods at issue are limited or prohibited, it could greatly lengthen the time needed to permit new reserves, significantly increase our operational costs, make it more difficult to economically recover a significant portion of our reserves and lead to a material adverse effect on our financial condition and results of operation. We may not be able to increase the price we charge for coal to cover higher production costs without reducing customer demand for our coal. See "Legal Proceedings" contained in Item 3 of this Annual Report on Form 10-K.

Table of Contents

New government regulations as a result of recent mining accidents are increasing our costs.

Both the federal and state governments impose stringent health and safety standards on the mining industry. Regulations are comprehensive and affect nearly every aspect of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters. As a result of past mining accidents,additional federal and state health and safety regulations have been adopted that have increased operating costs and affect our mining operations. State and federal legislation has been adopted that, among other things, requires additional oxygen supplies, communication and tracking devices, refuge chambers, stronger seal construction and monitoring standards and mine rescue teams. The legislation also raised the maximum civil penalty for certain violations of federal mine safety regulations to $220,000 from $60,000. We expect that new regulations or stricter enforcement of existing regulations will increase our costs related to worker health and safety. Additionally, we could be subject to civil penalties and other penalties if we violate mining regulations.

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

The geological characteristics of Northern and 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 the Powder River Basin in northeastern Wyoming and southeastern Montana, permitting, licensing and other environmental and regulatory requirements are more dynamic and thus more costly and time-consuming to satisfy. These factors could materially adversely affect the mining operations and cost structures of, and customers' ability to use coal produced by, our mines in Northern and Central Appalachia.

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, incur capital expenditures to re-open the mines and negotiate settlements with the customers, which may include price reductions, the reduction of commitments or the extension of time for delivery, terminate customers' contracts or face claims initiated by our customers against us. The resolution of these challenges could have an adverse impact on our financial position, results of operations or cash flows.

We may be unable to obtain and renew permits necessary for our operations, which would reduce our production, cash flow and profitability.

Mining companies must obtain numerous permits that impose strict regulations on various environmental and safety matters in connection with coal mining. These include permits issued by various federal and state agencies and regulatory bodies. The permitting rules are complex and may change over time, making our ability to comply with the applicable requirements more difficult or even impossible, thereby precluding continuing or future mining operations. The public has certain rights to comment upon and otherwise engage in the permitting process, including through court intervention. Accordingly, the permits we need may not be issued, maintained or renewed, or may not be issued or renewed in a timely fashion or may involve requirements that restrict our ability to conduct our mining operations. An inability to conduct our mining operations pursuant to applicable permits would reduce our production, cash flows and profitability.

41

Table of Contents

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

The SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining, as well as the surface effects of deep mining. Estimates of our total reclamation and mine-closing liabilities are based upon permit requirements, engineering studies and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by our management and engineers. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. We adopted SFAS No. 143, Accounting for Asset Retirement Obligations ("SFAS No. 143"), effective January 1, 2003. SFAS No. 143 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. 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 behalf of us. The resulting estimated reclamation and mine closure obligations could change significantly if actual amounts change significantly from our assumptions.

Our operations may substantially impact the environment or cause exposure to hazardous materials, and our properties may have significant environmental contamination, any of which could result in material liabilities to us.

We use, and in the past have used, hazardous materials and generate, and in the past have generated, hazardous wastes. In addition, many of the locations that we own or operate were used for coal mining and/or involved hazardous materials usage either before or after we were involved with those locations. We may be subject to claims under federal and state statutes and/or common law doctrines, for toxic torts, natural resource damages and other damages, as well as the investigation and clean up of soil, surface water, groundwater and other media. Such claims may arise, for example, out of current or former activities at sites that we own or operate currently, as well as at sites that we or predecessor entities owned or operated in the past, and at contaminated sites that have always been owned or operated by third parties. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the remediation costs or other damages, or even for the entire share. We have from time to time been subject to claims arising out of contamination at our own and other facilities and may incur such liabilities in the future.

We use, and in the past have used, alkaline CCBs during the reclamation process at certain of our mines to aid in preventing the formation of acid mine drainage. Use of CCBs on a mined area is subject to regulatory approval and is allowed only after it is proved to be a beneficial use. If in the future CCBs were to be classified as a hazardous waste or if more stringent disposal requirements were to be otherwise established for these wastes, we may be required to cease using CCBs and find a replacement alkaline material for this purpose, which may add to the cost of mine reclamation.

We maintain extensive coal slurry impoundments at a number of our mines. Such impoundments are subject to regulation. Slurry impoundments maintained by other coal mining operations have been known to fail, releasing large volumes of coal slurry. Structural failure of an impoundment can result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure. We have commenced measures to modify our method of operation at one surface impoundment containing slurry wastes in order to reduce the risk of releases to the environment from it, a process that will take several years to complete. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental contamination and associated liability, as well as for fines and penalties.

These and other impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations and environmental conditions at our properties, could result in costs and liabilities that would materially and adversely affect us.

Table of Contents

Extensive environmental regulations affect our customers and could reduce the demand for coal as a fuel source and cause our sales to decline.

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 coke ovens and electric power plants, which are the largest end-users of our coal. Such regulations will require significant emissions control expenditures for many coal-fired power plants to comply with applicable ambient air quality standards. As a result, these generators may switch to other fuels that generate less of these emissions, possibly reducing future demand for coal and the construction of coal-fired power plants.

The Federal Clean Air Act, including the Clean Air Act Amendments of 1990, and corresponding state laws that regulate emissions of materials into the air affect coal mining operations both directly and indirectly. Measures intended to improve air quality that reduce coal's share of the capacity for power generation could diminish our revenues and harm our business, financial condition and results of operations. The price of lower sulfur coal may decrease as more coal-fired utility power plants install additional pollution control equipment to comply with stricter sulfur dioxide emission limits, which may reduce our revenues and harm our results. In addition, regulatory initiatives including the nitrogen oxide rules, new ozone and particulate matter standards, regional haze regulations, new source review, regulation of mercury emissions and legislation or regulations that establish restrictions on greenhouse gas emissions or provide for other multiple pollutant reductions could make coal a less attractive fuel to our utility customers and substantially reduce our sales.

Various new and proposed laws and regulations may require further reductions in emissions from coal-fired utilities. The EPA is reconsidering the March 2005 Clean Air Interstate Rule pursuant to a court order which remanded, but did not vacate, that rule, which further regulated sulfur dioxide and nitrogen oxides from coal-fired power plants. Among other things, in affected states, the rule mandates reductions in sulfur dioxide emissions by approximately 45% below 2003 levels by 2010, and by approximately 57% below 2003 levels by 2015. The stringency of this cap may require many coal-fired sources to install additional pollution control equipment, such as wet scrubbers. The EPA has announced that it intends to initiate a rulemaking to adopt technology-based standards for mercury emissions form coal-fired power plants in response to a court order which vacated and remanded its 2005 Clean Air Mercury Rule. The EPA has not determined how to respond to the Court's decision. In February 2008, the Court ruled that the EPA's 2005 Clean Air Mercury Rule violates the Clean Air Act and gave the agency two years to develop mercury emissions standards. Some states, including Georgia and North Carolina, are adopting or proposing to adopt more stringent restrictions on mercury emissions than those contained in the remanded Clean Air Mercury Rule. These and other future standards could have the effect of making the operation of coal-fired plants less profitable, thereby decreasing demand for coal. 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.

There have been several recent proposals in Congress that are designed to further reduce emissions of sulfur dioxide, nitrogen oxides and mercury from power plants, and certain ones could regulate additional air pollutants. If such initiatives are enacted into law, power plant operators could choose fuel sources other than coal to meet their requirements, thereby reducing the demand for coal.

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

43

Table of Contents

New and pending laws regulating the environmental effects of emissions of greenhouse gases could impose significant additional costs to doing business for the coal industry and/or a shift in consumption to non-fossil fuels.

Greenhouse gas emissions have increasingly become the subject of a large amount of international, national, state and local attention. Although the United States did not join the 1992 Framework Convention on Global Climate Change, commonly known as the Kyoto Protocol, future regulation of greenhouse gas could occur either pursuant to future U.S. treaty obligations or pursuant to statutory or regulatory changes under the Clean Air Act. Increased efforts to control greenhouse gas emissions, including the future joining of the Kyoto Protocol, could result in reduced demand for coal if electric power generators switch to lower carbon sources of fuel. If the United States were to ratify the Kyoto Protocol, the United States would be required to reduce greenhouse gas emissions to 93% of 1990 levels in a series of phased reductions from 2008 to 2012.

Coal-fired power plants can generate large amounts of carbon emissions, and, as a result, have become subject to challenge, including the opposition to any new coal-fired power plants or capacity expansions of existing plants, by environmental groups seeking to curb the environmental effects of emissions of greenhouse gases. Various legislation has been and will continue to be introduced in Congress which reflects a wide variety of strategies for reducing greenhouse gas emissions in the United States. These strategies include mandating decreases in carbon dioxide emissions from coal-fired power plants, instituting a carbon tax on emissions of carbon dioxide, banning the construction of new coal-fired power plants that are not equipped with technology to capture and sequester carbon dioxide, encouraging the growth of renewable energy sources (such as wind or solar power) or nuclear for electricity production, financing the development of advanced coal burning plants which have greatly reduced carbon dioxide emissions. Most states in the United States have taken steps to regulate greenhouse gas emissions. In addition, in Massachusetts v. Environmental Protection Agency, a U.S. Supreme Court decision in April 2007, the U.S. Supreme Court ruled in favor of twelve states and several cities of the United States against the EPA, and held that carbon dioxide and other greenhouse gases can qualify as pollutants under the Clean Air Act. As a result, the EPA may issue regulations related to greenhouse gas emissions.

Passage of additional state or federal laws or regulations regarding greenhouse gas emissions or other actions to limit carbon dioxide emissions could result in fuel switching, from coal to other fuel sources, by electric generators. Such laws and regulations could, for example, include mandating decreases in carbon dioxide emissions from coal-fired power plants, imposing taxes on carbon emissions, requiring certain technology to capture and sequester carbon dioxide from new coal-fired power plants and encouraging the production of non-coal-fired power plants. Political and regulatory uncertainty over future emissions controls have been cited as major factors in decisions by power companies to postpone new coal-fired power plants. If measures such as these or other similar measures, like controls on methane emissions from coal mines, are ultimately imposed by federal or state governments or pursuant to international treaty on the coal industry, our operating costs may be materially and adversely affected. Similarly, alternative fuels (non fossil-fuels) could become more attractive than coal in order to reduce carbon emissions, which could result in a reduction in the demand for coal and, therefore, our revenues.

Table of Contents

Risks Relating To Our Common Stock

Our leverage may harm our financial condition and results of operations.

Our total consolidated long-term debt as of December 31, 2008 was approximately $434.9 million and represented approximately 47% of our total capitalization, excluding current indebtedness of approximately $20.1 million, as of that date.

Our level of indebtedness could have important consequences on our future operations, including:

- making it more difficult for us to meet our payment and other obligations under our outstanding senior and convertible notes and our other outstanding debt;
- resulting in an event of default if we fail to comply with the financial and other restrictive covenants contained in our debt agreements, which could result in all of our debt becoming immediately due and payable;
- subjecting us to the risk of increased sensitivity to interest rate increases on our indebtedness with variable interest rates, including borrowings under our senior credit facility;
- reducing the availability of our cash flow to fund working capital, capital expenditures, acquisitions and other general corporate purposes, and limiting our ability to obtain additional financing for these purposes;
- limiting our flexibility in planning for, or reacting to, and increasing our vulnerability to, changes in our business, the industry in which we operate and the general economy; and
- placing us at a competitive disadvantage compared to our competitors that have less debt or are less leveraged.

If new debt is added to our and our subsidiaries' current debt levels, the related risks that we and they now face could intensify. In addition to the principal repayments on our outstanding debt, we have other demands on our cash resources, including, among others, capital expenditures and operating expenses.

Our ability to pay principal and interest on and to refinance our debt depends upon the operating performance of our subsidiaries, which will be affected by, among other things, general economic, financial, competitive, legislative, regulatory and other factors, some of which are beyond our control. In particular, economic conditions could cause the price of coal to fall, our revenue to decline and hamper our ability to repay our indebtedness, including our outstanding senior and convertible notes.

Our business may not generate sufficient cash flow from operations and future borrowings may not be available to us under our senior credit facility or otherwise in an amount sufficient to enable us to pay our indebtedness including anticipated interest on the notes, or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness on or before maturity. We may not be able to refinance any of our indebtedness on commercially reasonable terms, on terms acceptable to us or at all.

Our ability and the ability of some of our subsidiaries to engage in some business transactions or to pursue our business strategy may be limited by the terms of our existing debt.

Our credit facility contains a number of financial covenants requiring us to meet financial ratios and financial condition tests. The indenture governing our outstanding senior notes and our senior credit facility also restrict our and our subsidiaries' ability to:

- incur additional debt or issue guarantees;
- pay dividends on, redeem or repurchase capital stock;
- allow our subsidiaries to issue new stock to any person other than us or any of our other subsidiaries;
- make certain investments;
- make acquisitions;
- incur, or permit to exist, liens;
- enter into transactions with affiliates;
- guarantee the debt of other entities, including joint ventures;
- merge or consolidate or otherwise combine with another company; and
- transfer or sell a material amount of our assets outside the ordinary course of business.

These covenants could adversely affect our ability to finance our future operations or capital needs or to execute preferred business strategies.

Table of Contents

Our ability to borrow under our credit facility will depend upon our ability to comply with these covenants and our borrowing base requirements. Our ability to meet these covenants and requirements may be affected by events beyond our control and we may not meet these obligations. From time to time, we have amended or revised our financial covenants, and have also received waivers of covenant compliance under our senior credit facility. However, we may not continue to receive waivers from our lenders or be permitted to amend the financial covenants. Our failure to comply with these covenants and requirements could result in an event of default under the indenture governing our outstanding senior notes that, if not cured or waived, could permit acceleration of our outstanding convertible and senior notes and permit foreclosure on any collateral granted as security under our senior credit facility. If our indebtedness is accelerated, we may not be able to repay the notes or borrow sufficient funds to refinance the notes. Even if we were able to obtain new financing, it may not be on commercially reasonable terms, on terms that are acceptable to us, or at all. If our debt is in default for any reason, our business, financial condition and results of operations could be materially and adversely affected.

We are subject to limitations on capital expenditures under our senior credit facility. Because of these limitations, we may not be able to pursue our business strategy to replace our equipment fleet as it ages, develop additional mines or pursue additional acquisitions without additional financing.

We may not be able to repurchase our Convertible Senior Notes if noteholders convert prior to maturity.

Upon the occurrence of specific events, our Convertible Senior Notes may become convertible, requiring us to settle in cash the principal amount of the note, and any excess conversion value may be settled in cash or in shares of our common stock, at our option, as provided by the terms of the indenture governing the Convertible Senior Notes. The Convertible Senior Notes are convertible at an initial conversion price, subject to adjustment, of $6.10 per share (approximately 163.8136 shares per $1,000 principal amount of the Convertible Senior Notes). If we elect to settle any excess conversion value of the Convertible Senior Notes in cash, the holder will receive, for each $1,000 principal amount, the conversion rate multiplied by a 20-day average closing price of the common stock as set forth in the indenture beginning on the third trading day after the Convertible Senior Notes are surrendered. We have $225.0 million of principal amount of Convertible Senior Notes outstanding. In the event that a holder elects to convert its Convertible Senior Note, we would need to seek a waiver or amendment from our lenders to fund any cash settlement of any such conversion from working capital and/or borrowings under our amended credit facility in excess of $25.0 million per year. There is no assurance we will have sufficient cash on hand or available to fund the $225.0 million or that we would receive a waiver or amendment, especially in light of the current credit environment. In addition, if a significant number of noteholders were to convert their notes prior to maturity, we may not have enough available funds at any particular time to make the required repayments. Our failure to repurchase converted notes at a time when noteholders have the right to convert would constitute a default under the indenture. This default would, in turn, constitute an event of default under our amended and restated credit facility and could constitute an event of default under our Senior Notes, any of which could cause repayment of the related debt to be accelerated after any applicable notice or grace periods. If debt repayment were to be accelerated, we may not have sufficient funds to repurchase the Convertible Senior Notes or repay the debt. Alternatively, upon conversion, we may issue additional stock to satisfy the payment obligation related to any excess conversion value which could lead to immediate and potentially substantial dilution in net tangible book value per share.

Changes in the accounting treatment of certain of our existing securities could decrease our earnings per share.

There may be, in the future, potentially new or different accounting pronouncements or regulatory rulings, which could impact the way we are required to account for our securities, and which may have an adverse impact on our future financial condition and results of operations. With respect to our convertible notes, we are required under accounting principles generally accepted in the United States of America (“GAAP”) as presently in effect to include in

outstanding shares for purposes of computing diluted earnings per share only a number of shares underlying the notes that, at the end of a given quarter, have a value in excess of the outstanding principal amount of the notes. This is because of the "net share settlement" feature of the notes, under which we are required to pay the principal amount of the notes in cash. The accounting method for net share settled convertible securities was recently considered by the FASB, which issued FASB Staff Position ("FSP") APB 14-1, Accounting for Convertible Debt Instruments That May be Settled in Cash Upon Conversion (Including Partial Cash Settlement) ("FSP APB 14-1"). FSP APB 14-1, which is effective for financial statements for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years, requires that net share settled convertible securities under which the debt and equity components of the security be bifurcated and accounted for separately. Adoption of FSP APB 14-1 will result in us recognizing additional interest expense.

The conditional conversion feature of the notes could result in a holder receiving less than the value of the common stock into which a note would otherwise be convertible.

At certain times, the notes are convertible into cash and, if applicable, shares of our common stock only if specified conditions are met. If these conditions are not met, a holder will not be able to convert the notes at that time, and, upon a later conversion, a holder may not be able to receive the value of the common stock into which the convertible notes would otherwise have been convertible had such conditions been met.

Our money market fund is vulnerable to market-specific risks that could adversely affect our financial position, future earnings or cash flows.

We currently have a portion of our assets invested in a money market fund. This investment is subject to investment market risk and our income from this investment could be adversely affected by a decline in value. In the case of money market accounts and other fixed income investment products, which invest in high-quality short-term money market instruments, as well as other fixed income securities, the value of the assets may decline as a result of changes in interest rates, an issuer's actual or perceived creditworthiness or an issuer's ability to meet its obligations. A significant decrease in the net asset value of the securities underlying the money market fund could cause a material decline in our net income and cash flows.

Table of Contents

Provisions of our debt could discourage an acquisition of us by a third-party.

Certain provisions of our debt could make it more difficult or more expensive for a third-party to acquire us. Upon the occurrence of certain transactions constituting a fundamental change, holders of both series of notes will have the right, at their option, to require us to repurchase, at a cash repurchase price equal to 100% of the principal amount plus accrued and unpaid interest on the notes, all of their notes or any portion of the principal amount of such notes in integral multiples of $1,000. We may also be required to issue additional shares of our common stock upon conversion of such notes in the event of certain fundamental changes.

Anti-takeover provisions in our charter documents and Delaware corporate law may make it difficult for our stockholders to replace or remove our current board of directors and could deter or delay third parties from acquiring us, which may adversely affect the marketability and market price of our common stock.

Provisions in our amended and restated certificate of incorporation and bylaws and in Delaware corporate law may make it difficult for stockholders to change the composition of our board of directors in any one year, and thus prevent them from changing the composition of management. In addition, the same provisions may make it difficult and expensive for a third-party to pursue a tender offer, change in control or takeover attempt that is opposed by our management and board of directors. Public stockholders who might desire to participate in this type of transaction may not have an opportunity to do so. These anti-takeover provisions could substantially impede the ability of public stockholders to benefit from a change in control or change our management and board of directors and, as a result, may adversely affect the marketability and market price of our common stock.

We are also subject to the anti-takeover provisions of Section 203 of the Delaware General Corporation Law. Under these provisions, if anyone becomes an “interested stockholder,” we may not enter into a “business combination” with that person for three years without special approval, which could discourage a third-party from making a takeover offer and could delay or prevent a change of control. For purposes of Section 203, “interested stockholder” means, generally, someone owning more than 15% or more of our outstanding voting stock or an affiliate of ours that owned 15% or more of our outstanding voting stock during the past three years, subject to certain exceptions as described in Section 203.

Under any change of control, the lenders under our credit facilities would have the right to require us to repay all of our outstanding obligations under the facility.

There may be circumstances in which the interests of our major stockholders could be in conflict with the interests of a stockholder or noteholder.

As of December 31, 2008, funds sponsored by WLR own approximately 16% of our common stock. Circumstances may occur in which WLR or other major investors may have an interest in pursuing acquisitions, divestitures or other transactions, including among other things, taking advantage of certain corporate opportunities that, in their judgment, could enhance their investment in us or another company in which they invest. These transactions might invoke risks to our other holders of common stock or adversely affect us or other investors.

We may from time to time engage in transactions with related parties and affiliates that include, among other things, business arrangements, lease arrangements for certain coal reserves and the payment of fees or commissions for the transfer of coal reserves by one operating company to another. These transactions, if any, may adversely effect our sales volumes, margins and earnings.

Table of Contents

If we do not meet the New York Stock Exchange continued listing requirements, our common stock may be delisted, and we may be required to repurchase or refinance our 9.00% Convertible Senior Notes Due 2012.

In order to maintain our listing on the New York Stock Exchange ("NYSE"), we must continue to meet the NYSE minimum share price listing rule, the minimum market capitalization rule and other continued listing criteria. If our common stock were delisted, it could (i) reduce the liquidity and market price of our common stock; (ii) negatively impact our ability to raise equity financing and access the public capital markets; and (iii) materially adversely impact our results of operations and financial condition. In addition, if our common stock is not listed on the NYSE or another national exchange, holders of our 9.00% senior convertible notes due 2012 will be entitled to require us to repurchase their convertible notes. Our credit facility and senior notes provide that the occurrence of this repurchase right constitutes a default pursuant to their respective agreements.

If our stockholders sell substantial amounts of our common stock, the market price of our common stock may decline.

As of December 31, 2008, we had 153,322,245 shares of common stock outstanding. The number of shares of common stock available for resale in the public market is limited in certain circumstances by restrictions under federal securities. All of the shares sold in our public offering, as well as all of the shares issued by us in the corporate reorganization, are freely tradable without restrictions or further registration under the Securities Act of 1933, as amended, except for any shares held by our affiliates, as defined in Rule 144 of the Securities Act. Additional shares of common stock underlying options granted or to be granted will become available for sale in the public market. We have also filed a registration statement on Form S-8 that registered 8,525,302 shares of common stock covering shares of restricted stock granted to our executives and the shares of common stock to be issued pursuant to the exercise of options we have granted or will grant under our employee stock option plan and a certain employment agreement. Our stock price could drop significantly if the holders of these restricted shares sell them or the market perceives they intend to sell them. These sales may also make it more difficult for us to sell securities in the future at a time and at a price we deem appropriate.

We may not pay dividends for the foreseeable future.

We may retain any future earnings to support the development and expansion of our business or make additional payments under our credit facilities and, as a result, we may not pay cash dividends in the foreseeable future. Our payment of any future dividends will be at the discretion of our board of directors after taking into account various factors, including our financial condition, operating results, cash needs, growth plans and the terms of any credit agreements that we may be a party to at the time. Our credit facilities limit us from paying cash dividends or other payments or distributions with respect to our capital stock in excess of certain limitations. In addition, the terms of any future credit agreement may contain similar restrictions on our ability to pay any dividends or make any distributions or payments with respect to our capital stock. Accordingly, investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize their investment.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

Table of Contents

ITEM 2. PROPERTIES

Coal Reserves

“Reserves” are defined by SEC Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. “Proven (Measured) Reserves” are defined by SEC Industry Guide 7 as reserves for which (1) 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 (2) 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. “Probable reserves” are defined by 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.

We estimate that there are approximately 291 million tons of coal reserves that can be developed by our existing operations, which will allow us to maintain current production levels for an extended period of time. ICG Natural Resources and CoalQuest own and lease all of our reserves that are not currently assigned to, or associated with, one of our mining operations. These reserves contain approximately 726 million tons of mid to high Btu, low and high sulfur coal located in Kentucky, West Virginia, Maryland, Illinois and Virginia. Our multi-region base and flexible product line allows us to adjust to changing market conditions and sustain high sales volume by supplying a wide range of customers.

Table of Contents

Our total coal reserves could support current production levels for more than 58 years. The following table provides the location of our mining operations and the type of coal produced at those operations as of January 1, 2009:

perations	Assigned or Unassigned (1)	Operating (O) or Development (D)	State	Mining Method Surface (S) or Underground (UG)	Total Proven and Probable Reserves (2)	Owned Proven and Probable Reserves	Leased Proven and Probable Reserves	Steam Proven and Probable Reserves	Metallurg Prov Pro Res
						(in million tons)			
Appalachia									
nergy Corp.	Assigned	O	MD	S	7.27	0.00	7.27	7.27	
	Unassigned	D	MD	S/UG	52.83	0.35	52.48	32.58	
lex Energy Corp.					60.10	0.35	59.75	39.85	
ning Co.	Assigned	O	WV	S	6.18	0.05	6.13	6.18	
	Unassigned	D	WV	S	0.00	0.00	0.00	0.00	
ot Mining Co.					6.18	0.05	6.13	6.18	
Mining Buckhannon									
	Assigned	O	WV	UG	28.50	13.16	15.34	14.86	
	Unassigned	D	WV	UG	30.55	28.81	1.74	0.00	
f Run Mining									
on Division					59.05	41.97	17.08	14.86	
	Assigned	O	WV	UG	47.33	30.41	16.92	0.00	
	Unassigned	D	WV	UG	4.94	4.94	0.00	0.00	
inel					52.27	35.35	16.92	0.00	
Development LLC	Unassigned (Hillman)	D	WV	UG	186.09	186.09	0.00	32.71	
Appalachia Total					363.69	263.81	99.88	93.60	
ppalachia									
	Assigned	O	WV	S	4.95	3.15	1.80	4.95	
	Unassigned	D	WV	S	6.70	0.00	6.70	6.70	
ern					11.65	3.15	8.50	11.65	
	Assigned	O	KY	S	61.94	26.12	35.82	61.94	
	Unassigned	D	KY	S	0.00	0.00	0.00	0.00	
ard					61.94	26.12	35.82	61.94	
e	Assigned	O	KY	UG	24.18	0.63	23.55	24.18	
nty	Assigned	O	KY	UG	3.42	2.93	0.49	3.42	
	Unassigned	D	KY	UG	11.78	0.93	10.85	11.78	
tt County					15.20	3.86	11.34	15.20	
	Assigned	O	KY	UG	10.03	0.00	10.03	10.03	
	Unassigned	D	KY	UG	2.20	0.00	2.20	2.20	
en					12.23	0.00	12.23	12.23	
ucky	Assigned	O	KY	S	2.94	2.39	0.55	2.94	
al Resources	Assigned	D	WV	S	14.70	0.00	14.70	14.70	
	Unassigned	D	WV	UG	30.20	2.21	27.99	30.20	
	(Jennie Creek)								
Natural Resources					44.90	2.21	42.69	44.90	
ountain	Assigned	O	VA	UG	5.05	0.00	5.05	5.05	

	Unassigned	D	VA	S/UG	22.02	0.00	22.02	22.02
l Powell Mountain					27.07	0.00	27.07	27.07
	Assigned	O	WV	UG	32.03	1.28	30.75	0.00
lf Energy, Inc.	Unassigned	D	VA	UG	25.91	0.00	25.91	0.00
	(Big Creek)							
ppalachia Total					258.05	39.64	218.41	200.11
	Assigned	O	IL	UG	42.58	8.93	33.65	42.58
	(Viper)							
ral Resources	Unassigned	D	IL	UG	352.88	352.88	0.00	352.88
r					395.46	361.81	33.65	395.46
en and Probable Reserves					1,017.20	665.26	351.94	689.17

(1) "Assigned reserves" means coal which has been committed by the coal company to operating mine shafts, mining equipment and plant facilities, and all coal which has been leased by the coal company to others. "Unassigned reserves" represent coal which has not been committed, and which would require new mineshafts, mining equipment or plant facilities before operations could begin in the property. The primary reason for this distinction is to inform investors which coal reserves will require substantial capital investment before production can begin.

(2) The proven and probable reserves are reported as recoverable reserves, which is that part of a coal deposit which could be economically and legally extracted or produced at the time of the reserve determination, taking into account mining recovery and preparation plant yield.

(3) Beckley and White Wolf Energy, Inc. meet historical metallurgical coal quality specifications.

(4) We sold coal with ash and sulfur contents as high as 10% and 1.5%, respectively, into the metallurgical market from Vindex Energy, Buckhannon and Sentinel in 2008. Similarly, we believe all production from Vindex Energy and portions of Hillman could be sold on this metallurgical market when production begins.

Table of Contents

The following table provides the "quality" (average moisture, ash and sulfur contents and Btu per pound) of our coal reserves as of January 1, 2009:

		As Received Quality					Total Reserves	
ing Operations	Assigned or Unassigned (1)	% Moisture	% Ash	% Sulfur	Btu/lb.	Lbs. SO2/ million Btu's	<1.2 lbs. SO2 Compliance	>1.2 lbs SO2 Non-Compli
thern Appalachia								
dex Energy Corp.(3)	Assigned	4.66	19.27	1.80	11,702	3.07	0.00	
	Unassigned	6.00	13.10	1.75	12,613	2.78	0.00	5
l Vindex Energy Corp.		5.84	13.85	1.76	12,503	2.81	0.00	6
iot Mining Co.	Assigned	6.00	14.96	2.67	11,830	4.52	0.00	
	Unassigned	6.00	19.06	2.13	11,240	3.79	0.00	
Total Patriot Mining Co.		6.00	14.96	2.67	11,830	4.52	0.00	
f Run Mining Buckhannon Division(3)	Assigned	6.00	8.07	2.21	13,070	3.39	0.00	2
	Unassigned	6.00	8.92	0.99	13,069	1.52	0.00	3
l Wolf Run Mining Buckhannon Division		6.00	8.51	1.58	13,069	2.42	0.00	5
inel(3)	Assigned	6.00	8.38	1.48	13,184	2.25	0.00	4
	Unassigned	6.00	8.04	1.44	13,353	2.15	0.00	
l Sentinel		6.00	8.35	1.48	13,200	2.24	0.00	5
lQuest Development LLC(3)	Unassigned (Hillman)	6.00	9.25	1.15	13,145	1.76	0.00	18
thern Appalachia Total							0.00	36
tral Appalachia								
ern	Assigned	6.00	14.42	1.24	11,964	2.07	0.00	
	Unassigned	6.00	14.42	1.24	11,964	2.07	0.00	
l Eastern		6.00	14.42	1.24	11,964	2.07	0.00	1
ard	Assigned	6.00	12.59	1.38	12,070	2.28	0.00	6
t Ridge	Assigned	6.00	8.15	1.39	12,768	2.17	1.36	2
tt County	Assigned	6.09	8.73	1.78	12,799	2.78	0.31	
	Unassigned	6.00	6.90	1.58	13,051	2.42	0.00	1
l Knott County		6.02	7.31	1.62	12,994	2.50	0.31	1
en	Assigned	6.00	8.00	1.18	12,787	1.85	0.00	1
	Unassigned	6.00	4.10	2.07	13,477	3.07	0.00	
l Raven		6.00	7.30	1.34	12,911	2.08	0.00	1
Kentucky	Assigned	5.88	9.37	0.87	12,450	1.40	0.00	
Natural Resources	Assigned	7.00	9.65	0.75	12,281	1.22	9.59	
	Unassigned	7.00	4.92	1.27	13,254	1.92	0.00	3
	(Jennie Creek)							
l ICG Natural Resources		7.00	6.47	1.10	12,935	1.70	9.59	3
ell Mountain	Assigned	6.00	3.92	0.62	14,428	0.86	5.05	
	Unassigned	6.00	8.38	2.01	13,194	3.04	6.46	1
Total Powell Mountain		6.00	6.81	1.75	13,476	2.60	11.51	1
kley(2)	Assigned (Beckley)	6.00	4.87	0.70	13,913	1.01	32.03	
te Wolf Energy, Inc.(2)	Unassigned (Big Creek)	6.00	4.09	0.63	14,150	0.89	25.91	

tral Appalachia Total							80.71	17
er								
ois	Assigned (Viper)	16.00	8.80	2.86	10,692	5.35	0.00	4
Natural Resources	Unassigned	12.53	9.32	2.93	10,986	5.33	0.00	35
l Other		12.90	9.27	2.92	10,954	5.33	0.00	39
l Proven and Probable Reserves							80.71	93

(1) "Assigned reserves" means coal which has been committed by the coal company to operating mine shafts, mining equipment and plant facilities, and all coal which has been leased by the coal company to others. "Unassigned reserves" represent coal which has not been committed, and which would require new mine shafts, mining equipment or plant facilities before operations could begin in the property. The primary reason for this distinction is to inform investors which coal reserves will require substantial capital investment before production can begin.

(2) Beckley and White Wolf Energy, Inc. meet historical metallurgical coal quality specifications.

(3) We sold coal with ash and sulfur contents as high as 10% and 1.5%, respectively, into the metallurgical market from Vindex Energy, Buckhannon and Sentinel in 2008. Similarly, we believe all production from Vindex Energy and portions of Hillman could be sold on this metallurgical market when production begins.

Table of Contents

Our reserve estimate is based on geological data assembled and analyzed by our staff of geologists and engineers. Reserve estimates are periodically updated to reflect past coal production, new drilling information and other geologic or mining data. Acquisitions, sales or dispositions of coal properties will also change the reserves. We estimate that we controlled 1,017 million tons of reserves at December 31, 2008. Changes in mining methods may increase or decrease the recovery basis for a coal seam, as will plant processing efficiency tests. We maintain reserve information in secure computerized databases, as well as in hard copy. The ability to update and/or modify the reserves is restricted to a few individuals and the modifications are documented.

Actual reserves may vary substantially from the estimates. Estimated minimum recoverable reserves are comprised of coal that is considered to be merchantable and economically recoverable by using mining practices and techniques prevalent in the coal industry at the time of the reserve study, based upon then-current prevailing market prices for coal. We use the mining method that we believe will be most profitable with respect to particular reserves. We believe the volume of our current reserves exceeds the volume of our contractual delivery requirements. Although the reserves shown in the table above include a variety of qualities of coal, we presently blend coal of different qualities to meet contract specifications. See “Risk Factors—Risks Relating To Our Business.”

We currently own approximately 65% of our coal reserves, with the remainder of our coal reserves subject to leases from third-party landowners. Generally, these leases convey mining rights to the coal producer in exchange for a percentage of gross sales in the form of a royalty payment to the lessor, subject to minimum payments. Leases generally last for the economic life of the reserves. The average royalties paid by us for coal reserves from our producing properties was $2.94 per ton in 2008, representing approximately 5.2% (net of freight and handling) of our coal sales revenue in 2008. Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to lands and reserves of the lessors or grantors and the boundaries of our leased priorities are not completely verified until we prepare to mine those reserves.

Non-Reserve Coal Deposits

Non-reserve coal deposits are coal-bearing bodies that have been sufficiently sampled and analyzed in trenches, outcrops, drilling and underground workings to assume continuity between sample points and, therefore, warrant further exploration stage work. However, this coal does not qualify as a commercially viable coal reserve as prescribed by SEC standards until a final comprehensive evaluation based on unit cost per ton, recoverability and other material factors concludes legal and economic feasibility. Non-reserve coal deposits may be classified as such by either limited property control or geologic limitations, or both.

Table of Contents

The following table provides the location of our mining operations and the type and amount of non-reserve coal deposits at those complexes as of January 1, 2009:

Mining Operations	Assigned or Unassigned (1)	Operating (O) or Development (D)	State	Mining Method Surface (S) or Underground (UG)	Total Non-Reserve Coal Deposits	Steam Non-Reserve Coal Deposits	Metallurgical(2)(3) Non-Reserve Coal Deposits
					(in million tons)		
Northern Appalachia							
Vindex Energy Corp.	Unassigned	D	MD	S	0.44	0.00	0.44
Wolf Run Mining Buckhannon Division	Assigned	O	WV	UG	1.46	1.46	0.00
	Unassigned	D	WV	UG	2.24	2.24	0.00
Total Wolf Run Mining Buckhannon Division					3.70	3.70	0.00
Sentinel	Assigned	O	WV	UG	1.64	1.64	0.00
	Unassigned	D	WV	UG	0.76	0.76	0.00
Total Sentinel					2.40	2.40	0.00
CoalQuest Development LLC	Unassigned (Hillman)	D	WV	UG	38.14	38.14	0.00
Upshur Property	Unassigned (Upshur)		WV	S	92.96	92.96	0.00
Northern Appalachia Total					137.64	137.20	0.44
Central Appalachia							
Eastern	Assigned	O	WV	S	0.02	0.02	0.00
Hazard	Assigned	O	KY	S	6.39	6.39	0.00
Flint Ridge	Assigned	O	KY	UG	0.94	0.94	0.00
Knott County	Assigned	O	KY	UG	0.00	0.00	0.00
East Kentucky	Assigned (Mount Sterling)	O	KY	S	0.00	0.00	0.00
ICG Natural Resources	Assigned (Jennie Creek)	D	WV	S	0.22	0.22	0.00
ICG Natural Resources	Unassigned (Martin Co., Muhlenberg Co.)	D	KY	S/UG	35.59	35.59	0.00
ICG Natural Resources	Unassigned (Mobil)		WV	UG	21.62	21.62	0.00
Powell Mountain	Unassigned	O	VA	UG	46.07	46.07	0.00

Beckley	Unassigned	O	WV	UG	1.88	0.00	1.88
Juliana Mining Co., Inc.	Unassigned	D	WV	S/UG	3.10	3.10	0.00
White Wolf Energy, Inc.	Unassigned (Big Creek)	D	VA	UG	2.58	2.58	0.00
Central Appalachia Total					118.41	116.53	1.88
Other							
Illinois	Assigned (Viper)	O	IL	UG	38.47	38.47	0.00
ICG Natural Resources	Unassigned (Illinois)		IL	UG	57.92	57.92	0.00

Table of Contents

Mining Operations	Assigned or Unassigned(1)	Operating (O) or Development (D)	State	Mining Method Surface (S) or Underground (UG)	Total Non-Reserve Coal Deposits	Steam Non-Reserve Coal Deposits (in million tons)	Metallurgical(2)(3) Non-Reserve Coal Deposits
ICG Natural Resources	Unassigned (Arkansas)		AR	S	39.15	39.15	0.00
	Unassigned (California)		CA	UG	10.00	10.00	0.00
	Unassigned (Ohio)		OH	UG	98.00	98.00	0.00
	Unassigned (Montana)		MT	S	12.00	12.00	0.00
	Unassigned (Washington)		WA	S	9.86	9.86	0.00
Total Other					265.40	265.40	0.00
Total Non-Reserve Coal Deposits					521.45	519.13	2.32

(1) "Assigned non-reserve coal deposits" mean coal which has been committed by the coal company to operating mine shafts, mining equipment and plant facilities, and all coal which has been leased by the coal company to others. "Unassigned non-reserve coal deposits" represent coal which has not been committed, and which would require new mine shafts, mining equipment or plant facilities before operations could begin in the property.

(2) Beckley and White Wolf Energy, Inc. meet historical metallurgical coal quality specifications.

(3) We sold coal with ash and sulfur contents as high as 10% and 1.5%, respectively, into the metallurgical market from Vindex Energy, Buckhannon and Sentinel in 2008. Similarly, we believe all production from Vindex Energy and portions of Hillman can be sold on this metallurgical market.

The following table provides the "quality" (average moisture, ash and sulfur contents and Btu per pound) of our non-reserve coal deposits as of January 1, 2009:

		As Received Quality				
Mining Operations	Assigned or Unassigned (1)	% Moisture	% Ash	% Sulfur	Btu/ lb.	Lbs. SO2/ million Btu's
Northern Appalachia						
Vindex Energy Corp. (3)	Unassigned	6.00	14.15	1.49	12,409	2.40
Wolf Run Mining Buckhannon Division(3)	Assigned	6.00	7.43	2.83	13,086	4.32
	Unassigned	6.00	9.00	1.20	13,000	1.85
Sentinel(3)	Assigned	6.00	8.30	1.40	13,100	2.14
	Unassigned	6.00	8.30	1.40	13,100	2.14

Upshur Property	Unassigned	6.00	43.00	2.00	8,000	5.00
Central Appalachia						
Eastern	Assigned	6.00	12.20	1.20	12,400	1.94
Hazard	Assigned	6.00	13.51	1.07	11,880	1.79
Flint Ridge	Assigned	6.00	8.15	1.39	12,768	2.18
Knott County	Assigned	N/A	N/A	N/A	N/A	N/A
East Kentucky	Assigned (Mt. Sterling)	N/A	N/A	N/A	N/A	N/A
ICG Natural Resources	Assigned (Jennie Creek)	7.00	7.78	0.63	12,609	1.01
ICG Natural Resources	Unassigned (Martin Co., Muhlenberg Co.)	6.00	11.47	1.91	11,780	3.24
ICG Natural Resources	Unassigned (Mobil)	6.00	12.50	1.10	12,000	1.83
Powell Mountain	Unassigned	6.00	5.78	1.21	13,348	1.81
Beckley(2)	Unassigned	6.00	4.80	0.70	13,800	1.01
Juliana Mining Co., Inc.	Unassigned	6.00	7.50	0.82	13,100	1.25
White Wolf Energy, Inc.(2)	Unassigned (Big Creek)	6.00	7.40	0.60	13,500	0.89

Table of Contents

		As received quality				
Mining operations	Assigned or Unassigned (1)	% Moisture	% Ash	% Sulfur	Btu/ lb.	Lbs. SO2/ million Btu's
Other						
Illinois	Assigned (Viper)	16.00	9.50	3.50	10,500	6.67
ICG Natural Resources	Unassigned (Illinois)	13.00	9.00	3.00	11,000	5.45
ICG Natural Resources	Unassigned (Arkansas)	N/A	8.00	0.40	5,650	1.42
	Unassigned (California)	6.00	13.00	3.50	11,700	5.98
	Unassigned (Ohio)	6.00	8.40	2.50	12,650	3.95
	Unassigned (Montana)	N/A	8.00	0.30	8,900	0.67
	Unassigned (Washington)	N/A	8.00	0.50	7,025	1.42

(1) "Assigned non-reserve coal deposits" mean coal which has been committed by the coal company to operating mine shafts, mining equipment and plant facilities, and all coal which has been leased by the coal company to others. "Unassigned non-reserve coal deposits" represent coal which has not been committed, and which would require new mineshafts, mining equipment or plant facilities before operations could begin in the property.

(2) Beckley and White Wolf Energy, Inc. meet historical metallurgical coal quality specifications.

(3) We sold coal with ash and sulfur contents as high as 10% and 1.5%, respectively, into the metallurgical market from Vindex Energy, Buckhannon and Sentinel 2008. Similarly, we believe all production from Vindex Energy and portions of Hillman can be sold on this metallurgical market.

ITEM 3. LEGAL PROCEEDINGS

On August 23, 2006, a survivor of the Sago mine accident, Randal McCloy, filed a complaint in the Kanawha Circuit Court in Kanawha County, West Virginia. The claims brought by Randal McCloy and his family against us and certain of our subsidiaries, and against W.L. Ross & Co., and Wilbur L. Ross, Jr., individually, were dismissed on February 14, 2008, after the parties reached a confidential settlement. Sixteen other complaints have been filed in Kanawha Circuit Court by the representatives of many of the miners who died in the Sago mine accident, and several of these plaintiffs have filed amended complaints to expand the group of defendants in the cases. The complaints allege various causes of action against us and our subsidiary, Wolf Run Mining Company, one of our shareholders, W.L. Ross & Co., and Wilbur L. Ross Jr., individually, related to the accident and seek compensatory and punitive damages. In addition, the plaintiffs also allege causes of action against other third parties, including claims against the manufacturer of Omega block seals used to seal the area where the explosion occurred and against the manufacturer of self-contained self-rescuer ("SCSR") devices worn by the miners at the Sago mine. Some of these third parties have

been dismissed from the actions upon settlement. The amended complaints add other of our subsidiaries to the cases, including ICG, Inc., ICG, LLC and Hunter Ridge Coal Company, unnamed parent, subsidiary and affiliate companies of us, W.L. Ross & Co., and Wilbur L. Ross Jr., and other third parties, including a provider of electrical services and a supplier of components used in the SCSR devices. We believe that we are appropriately insured for these and other potential claims, and we have fully paid our deductible applicable to our insurance policies. In addition to the dismissal of the McCloy claim, we have settled and dismissed five other actions. These settlements required the release of us, our subsidiaries, W. L. Ross & Co., and Wilbur L. Ross, Jr. Some of the plaintiffs involved in one of the dismissed actions have sought permission from the Supreme Court of Appeals of West Virginia to appeal the settlement, alleging that the settlement negotiated by the decedent's estate should not have been approved by the trial court. The trial court overruled those plaintiffs' objections to the settlement, and, although the West Virginia Supreme Court of Appeals refused to stay the effectiveness of the settlement, the plaintiffs' petition for appeal to the West Virginia Supreme Court of Appeals was recently presented to the court. The court has not yet ruled whether it will accept the petition for appeal or decline to hear the appeal. We will vigorously defend ourselves against the remaining complaints and any appeal of any prior settlements.

Allegheny Energy Supply ("Allegheny"), the sole customer of coal produced at our subsidiary Wolf Run Mining Company's ("Wolf Run") Sycamore No. 2 mine, filed a lawsuit against Wolf Run, Hunter Ridge Holdings, Inc. ("Hunter Ridge"), and us in state court in Allegheny County, Pennsylvania on December 28, 2006, and amended its complaint on April 23, 2007. Allegheny claims that we breached a coal supply contract when we declared force majeure under the contract upon idling the Sycamore No. 2 in the third quarter of 2006. The Sycamore No. 2 mine was idled after encountering adverse geologic conditions and abandoned gas wells that were previously unidentified and unmapped. The amended complaint also alleges that the production stoppages constitute a breach of the guarantee agreement by Hunter Ridge and breach of certain representations made upon entering into the contract in early 2005, a claim that Allegheny has since voluntarily dropped. Allegheny claims that it will incur costs in excess of $100.0 million to purchase replacement coal over the life of the contract. We, Wolf Run and Hunter Ridge answered the amended complaint on August 13, 2007, disputing all of the remaining claims. On November 3, 2008, we, Wolf Run and Hunter Ridge filed an amended answer and counterclaim against the plaintiffs seeking to void the coal supply agreement due to, among other things, fraudulent inducement and conspiracy. The counterclaim alleges further that Allegheny breached a confidentiality agreement with Hunter Ridge, which prohibited the solicitation of its employees. After the coal supply agreement was executed, Allegheny hired the then-president of Anker Coal Group, Inc. (now Hunter Ridge) who engaged in negotiations on behalf of Wolf Run and Hunter Ridge. In addition to seeking a declaratory judgment that the coal supply agreement and guaranty be deemed void and unenforceable and rescission of the contracts, the counterclaim also seeks compensatory and punitive damages.

Table of Contents

On December 6, 2007, the Kentucky Waterways Alliance, Inc., and The Sierra Club sued the U.S. Army Corps of Engineers (the "ACOE") in the United States District Court for the Western District of Kentucky, Louisville Division (the "Court"), asserting that a permit to construct five valley fills was issued unlawfully to our Hazard subsidiary for its Thunder Ridge Surface mine. The suit alleges that the ACOE failed to comply with the requirements of both Section 404 of the Clean Water Act and the National Environmental Policy Act. Hazard has intervened in the suit to protect our interests. The ACOE suspended the Section 404 permit on December 26, 2007 in order to evaluate the issues raised by the plaintiffs. That evaluation is now in progress. If the ACOE reinstates the permit and the Court subsequently finds that the permit is unlawful, production could be materially affected at the Thunder Ridge Surface mine and the process of obtaining ACOE permits for coal mining activities in Kentucky could become more difficult.

On January 7, 2008, Saratoga Advantage Trust filed a class action lawsuit in the U.S. District Court for the Southern District of West Virginia against us and certain of our officers and directors. The complaint asserts claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder, based on alleged false and misleading statements in the registration statements filed in connection with our November 2005 reorganization and December 2005 public offering of common stock. In addition, the complaint challenges other of our public statements regarding our operating condition and safety record. We intend to vigorously defend the action.

On July 3, 2007, Taylor Environmental Advocacy Membership, Inc. ("T.E.A.M.") filed a petition to appeal the issuance of ICG Tygart Valley, LLC's ("Tygart Valley") Surface Mine Permit U-2004-06 against the West Virginia Department of Environmental Protection (the "WVDEP") in an action before the West Virginia Surface Mine Board (the "Board"). On December 10, 2007, the Board remanded the permit to the WVDEP for revision to certain provisions related to pre-mining water monitoring and cumulative hydrologic impacts. The WVDEP issued a modification on April 1, 2008 addressing those issues. T.E.A.M. filed an appeal of the WVDEP's approval of the permit modification on April 30, 2008. On October 7, 2008, the Board issued an order remanding the permit to the WVDEP requiring Tygart Valley to address a technical issue related to projected post-mining water quality. Tygart Valley has prepared and submitted a permit modification to alleviate the board's concerns. All site development will be suspended until the WVDEP has approved the permit modification. If the WVDEP issues the permit as modified, there will be additional opportunity for appeal by T.E.A.M.

In addition, from time to time, we are involved in legal proceedings arising in the ordinary course of business. These proceedings include assessments of penalties for citations and orders asserted by MSHA and other regulatory agencies, none of which are expected by management to, individually or in the aggregate, have a material adverse effect on us. In the opinion of management, we have recorded adequate reserves for liabilities arising in the ordinary course and it is management's belief there is no individual case or group of related cases pending that is likely to have a material adverse effect on our financial condition, results of operations or cash flows.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the quarter ended December 31, 2008.

Table of Contents

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange (the "NYSE") under the symbol "ICO." The following table sets forth, for the quarterly periods indicated, the high and low sales prices per share at the end of the day of our common stock reported on the NYSE.

	Stock Price	
	High	Low
2007		
January 1, 2007 through March 31, 2007	$ 5.61	$ 4.70
April 1, 2007 through June 30, 2007	6.48	5.24
July 1, 2007 through September 30, 2007	6.12	3.85
October 1, 2007 through December 31, 2007	5.57	4.45
2008		
January 1, 2008 through March 31, 2008	$ 6.98	$ 5.28
April 1, 2008 through June 30, 2008	13.28	6.01
July 1, 2008 through September 30, 2008	13.11	5.61
October 1, 2008 through December 31, 2008	5.98	1.50

These quotes are provided solely for informational purposes and may not be indicative of any price at which the shares of common stock may trade in the future.

As of February 19, 2009, there were approximately 243 holders of record of our common stock and an additional 48,402 stockholders whose shares were held for them in street name or nominee accounts.

Summary of Equity Compensation Plans

Shown below is information concerning our equity compensation plans and individual compensation arrangements as of December 31, 2008.

	Equity Compensation Plan Information		
Plan Category	Number of Securities To Be Issued Upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by stockholders(1)	2,512,140	$ 7.49	5,175,023
Equity compensation plans not approved by stockholders(2)	319,052	10.97	—
	2,831,192	$ 7.88	5,175,023

(1) We have two compensation plans: the 2005 Equity and Performance Incentive Plan, which was approved by stockholders on October 24, 2005, and the Director Compensation Plan.
(2) Represents stock option grant to purchase 319,052 shares of our common stock to our President and Chief Executive Officer pursuant to his employment agreement.

For additional information regarding our equity compensation plans, refer to the discussion in Note 13 to our audited consolidated financial statements included elsewhere in this report.

Dividend Policy

We have never declared or paid a dividend on our common stock. We may retain any future earnings to support the development and expansion of our business or make additional payments under our credit facilities and, as a result, we may not pay cash dividends in the foreseeable future. Our payment of any future dividends will be at the discretion of our board of directors after taking into account various factors, including our financial condition, operating results, cash needs, growth plans and the terms of any credit agreements that we may be a party to at the time. Our credit facility and indenture governing the senior notes limits us from paying cash dividends or other payments or distributions with respect to our capital stock in excess of certain limitations. In addition, the terms of any future credit agreement may contain similar restrictions on our ability to pay dividends or make payments or distributions with respect to our capital stock.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

International Coal Group, Inc. was formed in March 2005 as a wholly owned subsidiary of ICG, Inc. in order to effect a corporate reorganization. On November 18, 2005, we completed the reorganization. Prior to this reorganization, ICG, Inc. was the top-tier holding company. Upon completion of the reorganization, International Coal Group, Inc. became the new top-tier parent holding company. International Coal Group, Inc. is a holding company which does not have any independent external operations, assets or liabilities, other than through its operating subsidiaries. Prior to the acquisition of certain assets of Horizon as of September 30, 2004, ICG, Inc. did not have any material assets, liabilities or results of operations. The selected historical consolidated financial data is derived from International Coal Group, Inc.'s audited consolidated financial statements as of December 31, 2008 and 2007 and for the years ended December 31, 2008, 2007 and 2006 which is included elsewhere in this report. The selected historical consolidated financial data of International Coal Group, Inc. as of December 31, 2006, 2005 and 2004, the year ended December 31, 2005 and for the period May 13, 2004 (inception) to December 31, 2004 is derived from audited consolidated financial statements which are not included in this report. The selected historical consolidated financial data as of and for the nine months ended September 30, 2004 is derived from the consolidated financial statements of Horizon, our predecessor, which has been audited and is not included in this report. In the opinion of management, the financial data reflect all adjustments, consisting of all normal and recurring adjustments, necessary for a fair presentation of the results for those periods. The results of operations for interim periods are not necessarily indicative of the results to be expected for the full year or for any future period. The financial statements for the predecessor periods have been prepared on a "carve-out" basis to include our assets, liabilities and results of operations that were previously included in financial statements of Horizon. The financial statements for the predecessor periods include allocations of certain expenses, taxation charges, interest and cash balances relating to the predecessor based on management's estimates. The predecessor financial information is not necessarily indicative of our consolidated financial position, results of operations and cash flows if we had operated during the predecessor periods presented.

During the years ended December 31, 2008 and 2007, we recorded impairment losses of $37.4 million and $170.4 million, respectively. For 2008, $30.2 million of the loss related to impairment of goodwill at our ADDCAR subsidiary and $7.2 million related to impairment of long-lived assets. For 2007, the impairment loss related to impairment of goodwill at various of our business units. See Notes 4 and 5 to our consolidated financial statements for further discussion of the impairment losses.

On November 18, 2005, we consummated a business combination with each of Anker and CoalQuest. The results of operations of Anker and CoalQuest are included in our consolidated results of operations since that date.

Table of Contents

You should read the following data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with the financial information included elsewhere in this report, including the consolidated financial statements of International Coal Group, Inc. and the related notes thereto. Amounts shown are in thousands, except per share data.

	International Coal Group, Inc.					Horizon (Predecessor to International Coal Group, Inc.)
	Year ended December 31, 2008	Year ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2005	Period from May 13, 2004 to December 31, 2004	Period from January 1, 2004 to September 30, 2004
Statement of Operations Data:						
Coal sales revenues	$ 998,245	$ 770,663	$ 833,998	$ 619,038	$ 130,463	$ 346,981
Freight and handling revenues	45,231	29,594	18,890	8,601	880	3,700
Other revenues	53,260	48,898	38,706	22,852	5,648	22,841
Total revenues	1,096,736	849,155	891,594	650,491	136,991	373,522
Costs and Expenses:						
Cost of coal sales and other revenues	918,655	766,158	769,332	510,097	113,527	306,429
Freight and handling costs	45,231	29,594	18,890	8,601	880	3,700
Depreciation, depletion and amortization	96,047	86,517	72,218	43,076	7,932	27,547
Selling, general and administrative	38,147	33,325	34,578	28,828	4,205	8,477
Gain on sale of assets	(32,518)	(38,656)	(1,125)	(502)	(10)	(226)
Impairment loss	37,428	170,402	—	—	—	—
Writedowns and special items	—	—	—	—	—	10,018
Total costs and expenses	1,102,990	1,047,340	893,893	590,100	126,534	355,945
Income (loss) from operations	(6,254)	(198,185)	(2,299)	60,391	10,457	17,577

Interest and Other Income (Expense):						
Interest expense, net	(41,107)	(35,140)	(18,091)	(14,394)	(3,453)	(114,211)
Reorganization items	—	—	—	—	—	(12,471)
Other, net	—	319	2,113	3,302	16	1,442
Total interest and other income (expense)	(41,107)	(34,821)	(15,978)	(11,092)	(3,437)	(125,240)
Income (loss) before income taxes and minority interest	(47,361)	(233,006)	(18,277)	49,299	7,020	(107,663)
Income tax (expense) benefit	22,711	85,623	9,015	(16,986)	(2,660)	—
Minority interest	—	349	(58)	15	—	—
Net income (loss)	$ (24,650)	$ (147,034)	$ (9,320)	$ 32,328	$ 4,360	$ (107,663)

Table of Contents

	International Coal Group, Inc.					Horizon (Predecessor to International Coal Group, Inc.)
	Year ended December 31, 2008	Year ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2005	Period from May 13, 2004 to December 31, 2004	Period from January 1, 2004 to September 30, 2004
Earnings Per Share(1):						
Basic	$ (0.16)	$ (0.97)	$ (0.06)	$ 0.29	$ 0.04	$ —
Diluted	(0.16)	(0.97)	(0.06)	0.29	0.04	—
Weighted-Average Common Shares Outstanding (1):						
Basic	152,632,586	152,304,461	152,028,165	111,120,211	106,605,999	—
Diluted	152,632,586	152,304,461	152,028,165	111,161,287	106,605,999	—
Balance Sheet Data (at period end):						
Cash and cash equivalents	$ 63,930	$ 107,150	$ 18,742	$ 9,187	$ 23,967	$ —
Total assets	1,349,669	1,303,563	1,316,891	1,051,403	457,045	539,606
Long-term debt and capital leases	450,239	412,330	180,035	45,462	175,681	29
Total liabilities and minority interest	854,879	789,192	658,541	384,917	302,534	1,422,290
Total stockholders' equity (members' deficit)	494,790	514,371	658,350	666,486	154,511	(882,684)
Total liabilities and stockholders' equity (members' deficit)	1,349,669	1,303,563	1,316,891	1,051,403	457,045	539,606
Statement of Cash Flows Data:						
Net cash from:						
Operating activities	$ 77,953	$ 22,095	$ 55,591	$ 77,319	$ 30,264	$ 28,085
Investing activities	(123,264)	(126,531)	(160,769)	(104,713)	(329,168)	3,437
Financing activities	2,091	192,844	114,733	12,614	322,871	(32,381)
	132,024	160,431	165,658	108,231	5,583	6,624

Capital expenditures	

(1) Earnings per share data and average shares outstanding are not presented the period from January 1, 2004 to September 30, 2004 because they were prepared on a carve-out basis. The financial statements prepared for predecessor periods are carve-out financial statements reflecting the operations and financial condition of the Horizon assets acquired by us as of September 30, 2004 (collectively, the “combined companies”). The predecessor financial statements were prepared from the separate accounts and records maintained by the combined companies. In addition, certain assets and expense items represent allocations from Horizon. The accounts allocated include vendor advances, reclamation deposits and selling, general and administrative expenses.

Table of Contents

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion contains forward-looking statements that include numerous risks and uncertainties. Actual results could differ materially from those discussed in the forward-looking statements as a result of these risks and uncertainties, including those set forth in this Annual Report on Form 10-K under "Special Note Regarding Forward-Looking Statements" and under "Risk Factors." You should read the following discussion in conjunction with "Selected Financial Data" and the audited and unaudited consolidated financial statements and notes thereto of International Coal Group, Inc. and its subsidiaries appearing elsewhere in this Annual Report on Form 10-K.

Overview

We produce, process and sell steam coal from 13 regional mining complexes, which, as of December 31, 2008 were supported by 14 active underground mines, 14 active surface mines and 10 preparation plants located throughout West Virginia, Kentucky, Virginia, Maryland and Illinois. We have three reportable business segments, which are based on the coal regions in which we operate: (i) Central Appalachian, comprised of both surface and underground mines, (ii) Northern Appalachian, also comprised of both surface and underground mines and (iii) Illinois Basin, representing one underground mine. For more information about our reportable business segments, please see our audited consolidated financial statements and the notes thereto appearing elsewhere in this report. We also broker coal produced by others, the majority of which is shipped directly from the third-party producer to the ultimate customer. Our steam coal sales are primarily to large utilities and industrial customers in the Eastern region of the United States. In addition, we generate other revenues from the manufacture and operation of highwall mining systems, parts sales and shop services relating to those systems and coal handling and processing fees.

ICG, Inc. was formed by WL Ross & Co. LLC ("WLR"), and other investors, in May 2004 to acquire and operate competitive coal mining facilities. International Coal Group, Inc. was formed in March 2005 and became the parent holding company pursuant to a reorganization on November 18, 2005. Through the acquisition of key assets from the Horizon bankruptcy estate, the WLR investor group was able to target properties strategically located in Appalachia and the Illinois Basin with high quality reserves that are union free. With the proceeds of our December 2005 public offering, we retired substantially all of our then outstanding debt. Consistent with the WLR investor group's strategy to acquire attractive coal assets, the Anker and CoalQuest acquisitions further diversified our reserves in November 2005.

Our primary expenses are wages and benefits, repair and maintenance expenditures, diesel fuel purchases, blasting supplies, coal transportation costs, cost of purchased coal, royalties, freight and handling costs and taxes incurred in selling our coal.

Certain Trends and Economic Factors Affecting the Coal Industry

Our revenues depend on the price at which we are able to sell our coal. The pricing environment for domestic steam and metallurgical coal during the first three quarters of 2008 was relatively strong. In the fourth quarter of 2008, coal prices dropped drastically due to decreased demand for metallurgical coal caused by the global economic crisis and decreased demand for steam coal caused by high inventory levels at utilities. We have experienced increased operating costs for fuel and explosives, steel products, tires, healthcare and labor. While prices of labor and commodities increased over prior year, we expect that current economic conditions will reduce the inflationary pressures that drove up such costs in 2008. However, we expect to experience higher costs for surety bonds and letters of credit.

For additional information regarding some of the risks and uncertainties that affect our business and the industry in which we operate, see Item 1A. Risk Factors.

Critical Accounting Policies and Estimates

Our financial statements are prepared in accordance with accounting principles that are generally accepted in the United States of America. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amount of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities. Management evaluates its estimates on an on-going basis. Management bases its estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Actual results may differ from the estimates used. Our actual results have generally not differed materially from our estimates. However, we monitor such differences and, in the event that actual results are significantly different from those estimated, we disclose any related impact on our results of operations, financial position and cash flows. Note 2 to our audited consolidated financial statements provides a description of significant accounting policies. We believe that of these significant accounting policies, the following involve a higher degree of judgment or complexity:

Table of Contents

Revenue Recognition

Coal revenues result from sales contracts (long-term coal agreements or purchase orders) with electric utilities, industrial companies or other coal-related organizations, primarily in the eastern United States. Revenue is recognized and recorded at the time of shipment or delivery to the customer, at fixed or determinable prices and the title or risk of loss has passed in accordance with the terms of the sales agreement. Under the typical terms of these agreements, risk of loss transfers to the customers at the mine or port, where coal is loaded to the rail, barge, truck or other transportation sources that deliver coal to its destination.

Coal sales revenues also result from the sale of brokered coal produced by others. Revenue is recognized and recorded at the time of shipment or delivery to the customer, prices are fixed or determinable and the title or risk of loss has passed in accordance with the terms of the sale agreement. The revenues related to brokered coal sales are included in coal sales revenues on a gross basis and the corresponding cost of the coal from the supplier is recorded in cost of coal sales in accordance with Emerging Issues Task Force (“EITF”) 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent.

Freight and handling costs paid to third-party carriers and invoiced to coal customers are recorded as freight and handling costs and freight and handling revenues, respectively.

Other revenues primarily consist of contract mining income, coalbed methane sales, ash disposal services, equipment and parts sales, equipment rebuild and maintenance services, royalties and coal handling and processing income. With respect to other revenues recognized in situations unrelated to the shipment of coal, we carefully review the facts and circumstances of each transaction and apply the relevant accounting literature as appropriate and do not recognize revenue until the following criteria are met: persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the seller’s price to the buyer is fixed or determinable and collectibility is reasonably assured. Advance payments received are deferred and recognized in revenue as related income is earned.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts represents management’s best estimate of the amount of probable credit losses in our existing accounts receivable. We establish provisions for losses on accounts receivable when it is probable that all or part of the outstanding balance will not be collected. Management regularly reviews collectability and establishes or adjusts the allowance as necessary. Although we believe the estimate of credit losses we have made is reasonable and appropriate, inability to collect outstanding accounts receivable amounts could materially impact our reported financial results.

Reclamation

Our asset retirement obligations arise from the Federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. We record these reclamation obligations according to the provisions of SFAS No. 143. SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which the legal obligation associated with the retirement of the long-lived asset is incurred. Fair value of reclamation liabilities is determined based on the present value of the estimated future expenditures. 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, and the capitalized cost is depreciated over the useful life of the related asset. If the assumptions used to estimate the liability do not materialize as expected or regulatory changes were to occur, reclamation costs or obligations to perform reclamation and mine closing activities could be materially different than

currently estimated. 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 recorded. On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, additional costs resulting from accelerated mine closures and revisions to cost estimates and productivity assumptions to reflect current experience. At December 31, 2008, we had recorded asset retirement obligation liabilities of $79.2 million, including amounts reported as current liabilities. While the precise amount of these future costs cannot be determined with certainty, as of December 31, 2008, we estimate that the aggregate undiscounted cost of final mine closure is approximately $149.5 million.

Advance Royalties

We are required, under certain royalty lease agreements, to make minimum royalty payments whether or not mining activity is being performed on the leased property. These minimum payments may be recoupable once mining begins on the leased property. The recoupable minimum royalty payments are capitalized and amortized based on the units-of-production method at a rate defined in the lease agreement once mining activities begin. Unamortized deferred royalty costs are expensed when mining has ceased or a decision is made not to mine on such property. We have recorded an allowance for such circumstances based upon management estimates. We believe the estimate for losses is appropriate. However, actual amounts that we recoup through mining activity could vary resulting in a material impact to our financial results.

Inventories

Coal inventories are stated at lower of average cost or market and represent coal contained in stockpiles, including those tons that have been mined and hauled to our loadout facilities, but not yet shipped to customers. These inventories are stated in clean coal equivalent tons and take into account any loss that may occur during the processing stage. Coal must be of a quality that can be sold on existing sales orders to be carried as coal inventory. Coal inventory volumes are determined through survey procedures. The surveys involve assumptions, inherent uncertainties and the application of management judgment.

Parts and supplies inventories are valued at average cost, less an allowance for obsolescence. We establish provisions for losses in parts and supplies inventory values through analysis of turnover of inventory items and adjust the allowance as necessary.

Although we believe the estimates we have made with respect to the valuation of our coal and parts and supplies inventories are reasonable and appropriate, changes in assumptions (coal inventories) or actual utilization of items (parts and supplies inventories) could materially impact our reported financial results.

Table of Contents

Depreciation, Depletion and Amortization

Property, plant, equipment and mine development, which includes coal lands and mineral rights, are recorded at cost, which includes construction overhead and interest, where applicable. Expenditures for major renewals and betterments are capitalized while expenditures for maintenance and repairs are expensed as incurred.

Coal lands and mineral rights are depleted using the units-of-production method, based on estimated recoverable interest. The coal lands and mineral rights fair values are established by either using engineering studies or market values as established when coal lands and mineral rights are purchased on the open market. These values are then evaluated as to the number of recoverable tons contained in a particular mining area. Once the coal lands and mineral rights values are established, and the number of recoverable tons contained in a particular coal lands and mineral rights area is determined, a “units-of-production” depletion rate can be calculated. This rate is then utilized to calculate depletion expense for each period mining is conducted on a particular coal lands and mineral rights area.

Any uncertainty surrounding the application of the depletion policy is directly related to the assumptions as to the number of recoverable tons contained in a particular coal lands and mineral rights area. The amount of compensation paid for the coal lands and mineral rights is a set amount; however, the “recoverable tons” contained in the coal lands and mineral rights area are based on engineering estimates which can, and often do, change as the tons are mined. Any change in the number of “recoverable tons” contained in a coal lands and mineral rights area will result in a change in the depletion rate and corresponding depletion expense. For the year ended December 31, 2008, we recorded $2.0 million of depletion expense.

Mine development costs are amortized using the units-of-production method, based on estimated recoverable tons in the same manner described above.

Other property, plant and equipment are depreciated using the straight-line method based on estimated useful lives.

Coal Reserves

There are numerous uncertainties inherent in estimating quantities of economically recoverable coal reserves, many of which 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 by our internal engineers and geologists. Reserve estimates are periodically updated to reflect past coal production, new drilling information and other geologic or mining data. Acquisitions, sales or dispositions of coal properties will also change the reserves. Some of the factors and assumptions that impact economically recoverable reserve estimates include: (i) geological conditions; (ii) historical production from the area compared with production from other producing areas; (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, revenues and expenditures with respect to reserves will likely vary from estimates, and these variances may be material. At December 31, 2008, we had 1.0 billion tons of coal reserves.

Goodwill

As a result of a prior acquisition, we had assigned goodwill to our ADDCAR reporting unit based upon its estimated fair value. Pursuant to SFAS No. 142, goodwill and intangible assets that are determined to have an indefinite useful life are not amortized, but instead must be tested for impairment at least annually, and more frequently if a triggering event occurs. We perform our impairment test as of October 31 each year. The goodwill impairment test consists of two steps. The first identifies potential impairment by comparing the fair value of a reporting unit with its carrying amount, including goodwill. Fair value of a reporting unit is estimated using present value techniques, such as discounted cash flows of projected future operations developed by management or a weighting of income and market approaches. If the fair value of the reporting unit exceeds the carrying amount, goodwill is not considered impaired and the second step is not necessary. If the carrying value of the reporting unit exceeds the fair value, the second step is necessary to measure the amount of impairment loss by comparing the implied fair value of goodwill with its carrying amount. Implied fair value of goodwill is determined as the amount that the fair value of the assets of a business unit exceeds their carrying value, excluding goodwill. Impairment loss is measured as the amount of the carrying value of goodwill that exceeds its implied fair value. We performed an impairment test of goodwill related to our ADDCAR subsidiary as of October 31, 2008. The results of the 2008 annual impairment test indicated that its estimated fair value was less than the carrying amount of the respective business unit assets, including goodwill, and, therefore, was impaired. As a result, we recorded a $30.2 million non-cash impairment charge to reduce the carrying amount of these assets to their estimated fair value. Subsequent to this impairment charge, we have no goodwill remaining as of December 31, 2008.

Asset Impairments

We follow SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which requires that projected future cash flows from use and disposition of assets be compared with the carrying amounts of those assets when impairment indicators are present. When the sum of projected cash flows is less than the carrying amount, impairment losses are indicated. If the fair value of the assets is less than the carrying amount of the assets, an impairment loss is recognized. In determining such impairment losses, discounted cash flows or asset appraisals are utilized to determine the fair value of the assets being evaluated. Also, in certain situations, expected mine lives are shortened because of changes to planned operations. When that occurs and it is determined that the mine’s underlying costs are not recoverable in the future, reclamation and mine closing obligations are accelerated and the mine closing accrual is increased accordingly. To the extent it is determined asset carrying values will not be recoverable during a shorter mine life, a provision for such impairment is recognized. Recognition of an impairment will decrease asset values, increase operating expenses and decrease net income. In December 2008, we made the decision to permanently close our Sago mine during the first quarter of 2009. Upon making this decision, we performed an impairment test of related mine development costs, which resulted in a $7.2 million non-cash impairment charge to reduce the carrying amount of these assets to their estimated fair value. There were no other impairment charges related to long-lived assets recognized in 2008 as a result of our impairment tests.

Table of Contents

Derivative Financial Instruments

We use derivative financial instruments to manage interest rate risk. We do not use derivative financial instruments for trading or speculative purposes. Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended ("SFAS No. 133"), establishes accounting and reporting standards for derivative instruments and hedging activities. To qualify for hedge accounting under SFAS No. 133, the effectiveness of each hedging relationship is assessed both at hedge inception and at each reporting period thereafter. Also, at the end of each reporting period, ineffectiveness in the hedging relationships is measured as the difference between the change in fair value of the derivative instruments and the change in fair value of either the hedged items (fair value hedges) or expected cash flows (cash flow hedges). Ineffectiveness, if any, is recorded in interest expense. We have not designated our derivatives as hedging instruments and we recognize changes in the fair value of our derivatives in earnings in the period of change.

We enter into coal supply contracts with many of our customers. Certain of these agreements meet the definition of a derivative under SFAS No. 133. We analyze these agreements for qualification for the normal purchase, normal sale exception under the standard. We enter into the contracts with the intent to supply the related coal and do not trade the contracts. If we change our intentions with respect to delivery on or operation of these contracts, the accounting for the contracts could change.

Coal Supply Agreements

We have allocated purchase price to below-market coal supply agreements acquired in acquisitions accounted for as business combinations. In accordance with SFAS No. 141, Business Combinations, value was allocated to coal supply agreements based on discounted cash flows attributable to the difference between the below-market contract price and the prevailing market price at the date of acquisition and was capitalized and is being amortized on the basis of coal to be shipped over the term of the contracts. Determination of fair value requires management's judgment and often involves the use of significant estimates and assumptions.

Stock-Based Compensation

We account for our stock-based awards in accordance with SFAS No. 123(R), Share Based Payment ("SFAS No. 123(R)"). Under SFAS No. 123(R), stock-based compensation expense is generally measured at the grant date and recognized as expense over the vesting period of the award. We utilize restricted stock and stock options as part of our stock-based compensation program. Determining fair value requires us to make a number of assumptions, including expected term, risk-free rate and expected volatility. The assumptions used in calculating the fair value of stock-based awards represent our best estimates, but these estimates involve inherent uncertainties and the application of management judgment. Although we believe the assumptions and estimates we have made are reasonable and appropriate, changes in assumptions could materially impact our reported financial results.

Debt Issuance Costs

Debt issuance costs reflect fees incurred to obtain financing. Debt issuance costs related to our outstanding debt are amortized over the life of the related debt. From time to time, we write-off deferred financing fees as a result of amending or canceling related credit agreements. Such write-offs could be material and occur in the period that the decision to amend or cancel the related credit agreement is made.

Income Taxes

We account for income taxes in accordance with SFAS No. 109, which requires the recognition of deferred tax assets and liabilities using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. SFAS No. 109 also requires that deferred tax assets be reduced by a valuation allowance, if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including the timing of the realization of deferred tax liabilities, the expected level of future taxable income and available tax planning strategies. If future taxable income is lower than expected or if expected tax planning strategies are not available as anticipated, we may record a change to the valuation allowance through income tax expense in the period the determination is made.

Postretirement Medical Benefits

Some of our subsidiaries have long- and short-term liabilities for postretirement benefit cost obligations. Detailed information related to these liabilities is included in the notes to our consolidated financial statements included elsewhere in this report. Liabilities for postretirement benefits are not funded. The liability is actuarially determined and we use various actuarial assumptions, including the discount rate and future cost trends, to estimate the costs and obligations for postretirement benefits. The discount rate assumption reflects the rates available on a hypothetical portfolio of high-quality fixed income debt instruments whose cash flows match the timing and amount of expected benefit payments. The discount rate used to determine the net periodic benefit cost for postretirement medical benefits was 6.25% for the year ended December 31, 2008. We make assumptions related to future trends for medical care costs in the estimates of retiree healthcare and work-related injury and illness obligations. The future healthcare cost trend rate represents the rate at which healthcare costs are expected to increase over the life of the plan. The healthcare cost trend rate assumptions are determined primarily based upon our, and our predecessor's, historical rate of change in retiree healthcare costs. The postretirement expense in the operating period ended December 31, 2008 was based on an assumed heath care inflationary rate of 8.3% in the operating period decreasing to 5.0% in 2015, which represents the ultimate healthcare cost trend rate for the remainder of the plan life. A one-percentage point increase in the assumed ultimate healthcare cost trend rate would increase the service and interest cost components of the postretirement benefit expense for the year ended December 31, 2008 by $0.4 million and increase the accumulated postretirement benefit obligation at December 31, 2008 by $1.8 million. A one-percentage point decrease in the assumed ultimate healthcare cost trend rate would decrease the service and interest cost components of the postretirement benefit expense for the year ended December 31, 2008 by $0.4 million and decrease the accumulated postretirement benefit obligation at December 31, 2008 by $1.7 million. If our assumptions do not materialize as expected or if regulatory changes were to occur, actual cash expenditures and costs that we incur could differ materially from our current estimates.

Table of Contents

Workers' Compensation

Workers' compensation is a system by which individuals who sustain personal injuries due to job-related accidents are compensated for their disabilities, medical costs and, on some occasions, for the costs of their rehabilitation, and by which the survivors of workers who suffer fatal injuries receive compensation for lost financial support. The workers' compensation laws are administered by state agencies with each state having its own rules and regulations regarding compensation that is owed to an employee who is injured in the course of employment or the beneficiary of an employee that suffers fatal injuries in the course of employment. Our operations are covered through a combination of participation in a state run program and insurance policies. Our estimates of these costs are adjusted based upon actuarially determined amounts using a discount rate of 5.50% as of December 31, 2008. The discount rate assumption reflects the rates available on a hypothetical portfolio of high-quality fixed income debt instruments whose cash flows match the timing and amount of expected benefit payments. If we were to decrease our estimate of the discount rate to 4.5%, the present value of our workers' compensation liability would increase by approximately $0.4 million. If we were to increase our estimate of the discount rate to 6.5%, the present value of our workers' compensation liability would decrease by approximately $0.2 million. At December 31, 2008, we have recorded an accrual of $7.8 million for workers' compensation benefits. Actual losses may differ from these estimates, which could increase or decrease our costs.

Coal Workers' Pneumoconiosis

We are responsible under various federal statutes, and various states' statutes, for the payment of medical and disability benefits to eligible employees resulting from occurrences of coal workers' pneumoconiosis disease (black lung). Our operations are covered through a combination of participation in a state run program and insurance policies. We accrue for any self-insured liability by recognizing costs when it is probable that a covered liability has been incurred and the cost can be reasonably estimated. Our estimates of these costs are adjusted based upon actuarially determined amounts using a discount rate of 5.75% as of December 31, 2008. The discount rate assumption reflects the rates available on a hypothetical portfolio of high-quality fixed income debt instruments whose cash flows match the timing and amount of expected benefit payments. If we were to decrease our estimate of the discount rate to 4.75%, the present value of our black lung benefit liability would increase by approximately $13.7 million. If we were to increase our estimate of the discount rate to 6.75%, the present value of our black lung benefit liability would decrease by approximately $10.1 million. At December 31, 2008, we have recorded an accrual of $27.5 million for black lung benefits. Individual losses in excess of $0.5 million at the state level and $0.5 million at the federal level are covered by our large deductible stop loss insurance. Actual losses may differ from these estimates, which could increase or decrease our costs.

Coal Industry Retiree Health Benefit Act of 1992

The Coal Industry Retiree Health Benefit Act of 1992 (the "Coal Act") provides for the funding of health benefits for certain union retirees and their spouses or dependants. The Coal Act established the Combined Fund into which employers who are "signatory operators" and "related persons" are obligated to pay annual premiums for beneficiaries. The Coal Act also created a second benefit fund for miners who retired between July 21, 1992 and September 30, 1994 and whose former employers are no longer in business. Upon the consummation of the business combination with Anker, we assumed Anker's Coal Act liabilities, which were estimated to be $1.3 million at December 31, 2008. Actual losses may differ from these estimates, which could increase or decrease our costs. Our estimates of these costs are adjusted based upon actuarially determined amounts using a discount rate of 6.25% as of December 31, 2008. The discount rate assumption reflects the rates available on a hypothetical portfolio of high-quality fixed income debt instruments whose cash flows match the timing and amount of expected benefit payments. If we were to decrease our estimate of the discount rate to 5.25%, the present value of our Coal Act liability would increase by approximately

$0.9 million. If we were to increase our estimate of the discount rate to 7.25%, the present value of our Coal Act liability would decrease by approximately $0.8 million. Prior to the business combination with Anker, we did not have any liability under the Coal Act.

Table of Contents

Results of Operations

Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007

Revenues, coal sales revenues by operating segment and tons sold by operating segment

The following table depicts revenues for the years ended December 31, 2008 and 2007 for the indicated categories:

	Year ended December 31,		Increase (Decrease)	
	2008	2007	$ or Tons	%
	(in thousands, except percentages and per ton data)			
Coal sales revenues	$ 998,245	$ 770,663	$ 227,582	30%
Freight and handling revenues	45,231	29,594	15,637	53%
Other revenues	53,260	48,898	4,362	9%
Total revenues	1,096,736	849,155	247,581	29%
Tons sold	18,914	18,343	571	3%
Coal sales revenue per ton	$ 52.78	$ 42.01	$ 10.77	26%

The following table depicts coal sales revenues by operating segment for years ended December 31, 2008 and 2007:

	Year ended December 31,		Increase (Decrease)	
	2008	2007	$	%
	(in thousands, except percentages)			
Central Appalachian	$ 672,077	$ 512,352	$ 159,725	31%
Northern Appalachian	209,932	121,200	88,732	73%
Illinois Basin	69,796	60,368	9,428	16%
Ancillary	46,440	76,743	(30,303)	(39)%
Total coal sales revenues	$ 998,245	$ 770,663	$ 227,582	30%

The following table depicts tons sold by operating segment for the years ended December 31, 2008 and 2007:

	Year ended December 31,		Increase (Decrease)	
	2008	2007	Tons	%
	(in thousands, except percentages)			
Central Appalachian	11,617	11,323	294	3%
Northern Appalachian	3,937	3,291	646	20%
Illinois Basin	2,331	2,025	306	15%
Ancillary	1,029	1,704	(675)	(40)%
Total tons sold	18,914	18,343	571	3%

Coal sales revenues—Coal sales revenues are derived from sales of produced coal and brokered coal contracts. Coal sales revenues increased for the year ended December 31, 2008 compared to the year ended December 31, 2007 due to a 26% increase in sales realization per ton resulting from increased spot market and short-term contract sales entered into in order to capitalize on favorable market conditions during the first three quarters of 2008. Further impacting the

increase in coal sales revenue was a 3% increase in tons sold compared to the same period of 2007. Partially offsetting the impact of improved realization per ton and the increase in tons sold was a decrease in coal sales revenues attributable to the expiration of certain brokered coal contracts.

Central Appalachian. Coal sales revenues from our Central Appalachian segment for the year ended December 31, 2008 increased over the same period in 2007 primarily due to an increase of $12.61 per ton, which was driven by higher average prices of our coal sold pursuant to short-term supply agreements and on the spot market, including increased sales of metallurgical coal, primarily from increased production at our new Beckley operation.

Northern Appalachian. For the year ended December 31, 2008, our Northern Appalachian coal sales revenues increased due to an increase of $16.50 per ton resulting from higher average prices of coal sold pursuant to coal supply agreements and from an increase in sales of metallurgical coal, particularly on the spot market which provided advantageous pricing throughout much of 2008. Additionally, we experienced an increase in tons sold at certain of our complexes. The increase in tons sold was mainly attributable to our Sentinel complex continuing to increase production output to target levels, the ramp up of production at the formerly idled Harrison operation during 2008 and increased production resulting from investments in capital improvements made during the year.

Illinois Basin. The increase in coal sales revenues from our Illinois Basin segment was due to a 15% increase in tons sold resulting from increased short-term contract sales.

Ancillary. Our Ancillary segment’s coal sales revenues are comprised of coal sold under brokered coal contracts. We experienced a decrease in tons sold due to the expiration of certain brokered coal contracts.

Table of Contents

Freight and handling revenues—Freight and handling revenues represent reimbursement of freight and handling costs for certain shipments for which we initially pay the costs and are then reimbursed by the customer. Freight and handling revenues and costs increased for the year ended December 31, 2008 compared to the same period in 2007 primarily due to increased fuel surcharges and transportation rates. Additionally, we have entered into new sales contracts during 2008 that have increased freight and handling revenues and costs.

Other revenues—The increase in other revenues for the year ended December 31, 2008 compared to the year ended December 31, 2007 was due to additional ash disposal income, royalty income, sales of scrap materials, contract mining revenues and an increase in revenue generated from coalbed methane wells owned jointly by our subsidiary, CoalQuest, and CDX. The increases were partially offset by a decrease in revenue from our ADDCAR subsidiary, primarily related to the sale of a narrow bench highwall mining system in 2007.

Table of Contents

Costs and expenses

The following table depicts cost of operations for the years ended December 31, 2008 and 2007 for the indicated categories:

	Year ended December 31,		Increase (Decrease)	
	2008	2007	$	%
	(in thousands, except percentages and per ton data)			
Cost of coal sales	$ 882,983	$ 732,112	$ 150,871	21%
Freight and handling costs	45,231	29,594	15,637	53%
Cost of other revenues	35,672	34,046	1,626	5%
Depreciation, depletion and amortization	96,047	86,517	9,530	11%
Selling, general and administrative expenses	38,147	33,325	4,822	14%
Gain on sale of assets	(32,518)	(38,656)	6,138	16%
Impairment loss	37,428	170,402	(132,974)	(78)%
Total costs and expenses	$ 1,102,990	$ 1,047,340	$ 55,650	5%
Cost of coal sales per ton	$ 46.68	$ 39.91	$ 6.77	17%

The following table depicts cost of coal sales by operating segment for the years ended December 31, 2008 and 2007:

	Year ended December 31,		Increase (Decrease)	
	2008	2007	$	%
	(in thousands, except percentages)			
Central Appalachian	$ 595,683	$ 468,958	$ 126,725	27%
Northern Appalachian	193,389	147,745	45,644	31%
Illinois Basin	57,424	46,701	10,723	23%
Ancillary	36,487	68,708	(32,221)	(47)%
Cost of coal sales	$ 882,983	$ 732,112	$ 150,871	21%

Cost of coal sales—For the year ended December 31, 2008, our cost of coal sales increased compared to the year ended December 31, 2007 primarily as a result of a 17% increase in cost per ton, as well as a 3% increase in tons sold as described above.

Central Appalachian. Cost of coal sales from our Central Appalachian segment increased to $51.28 per ton for the year ended December 31, 2008 from $41.42 per ton for the year ended December 31, 2007 primarily as a result of increased labor and diesel fuel costs. Labor and benefit costs increased due to a tightening labor market resulting in the need to offer more competitive compensation packages. Diesel fuel costs increased over prior period as a result of higher per gallon fuel costs and additional gallons used. Further impacting the increase in cost of coal sales were increases in repairs and maintenance costs, contract labor costs, royalties, severance taxes and reclamation costs.

Northern Appalachian. Our Northern Appalachian segment cost of coal sales per ton increased to $49.13 for the year ended December 31, 2008 from $44.89 for the year ended December 31, 2007 due to increased labor, diesel fuel and repairs and maintenance costs resulting from certain high-dollar repairs performed during 2008. Additionally,

royalties, severance taxes and trucking costs increased at our Northern Appalachian segment primarily due to increased coal sales. Partially offsetting these increases was a decrease in purchased coal costs due to increased production at our Vindex and Sentinel complexes.

Illinois Basin. For the year ended December 31, 2008, our Illinois Basin cost of coal sales increased by $1.57 per ton primarily due to increased labor, roof control supplies and repairs and maintenance costs. Labor increased as demand for skilled miners increased over 2007. Roof control supplies increased as prices for steel were escalated for much of 2008. Additionally, repairs and maintenance costs have increased due to several repairs on underground mining equipment during 2008. Partially offsetting the aforementioned increases was a decrease in royalty expense resulting from increased mining of owned reserves rather than leased reserves as compared to 2007.

Ancillary. Cost of coal sales from our Ancillary segment decreased for the year ended December 31, 2008 primarily due to a decrease in purchased coal costs related to the expiration of certain brokered coal contracts.

Table of Contents

Cost of other revenues—For the year ended December 31, 2008, cost of other revenues increased primarily due to increases in labor and benefits, ash disposal transportation costs, gathering fees related to coalbed methane wells owned jointly by our subsidiary, CoalQuest, and CDX and highwall miner expenses. Partially offsetting the increases were the sale of a narrow bench highwall mining system by our subsidiary ADDCAR in 2007 with no comparable sale in 2008 and decreased water treatment costs at a non-producing property.

Depreciation, depletion and amortization—The principal component of the increase in depreciation, depletion and amortization expense was a decrease in amortization income on below-market coal agreements. Additionally, there were increases in depletion expense and depreciation expense due to significant additions to property, plant, equipment and mine development during 2008. These increases were partially offset by a decrease in amortization of coalbed methane well development costs.

Selling, general and administrative expenses—Selling, general and administrative expenses for the year ended December 31, 2008 increased primarily due to increases in bad debt expense, labor and benefit costs, sales tax expense and legal settlements. Partially offsetting these increases were decreases in taxes and licenses and legal and professional fees.

Gain on sale of assets—Gain on sale of assets for 2008 related primarily to exchanges of property, the sale of a used highwall mining system and the disposition of other assets. The gain recognized in 2007 was primarily attributable to the sale of the Denmark property.

Impairment loss—The impairment loss reflects the write-off of goodwill in 2008 associated with our ADDCAR subsidiary, as a result of the negative impact of several contributing factors which resulted in a reduction in the forecasted cash flows used to estimate fair value. During 2007, all goodwill associated with our Hazard, Knott County, East Kentucky and Eastern subsidiaries was deemed to be impaired and written-off. Additionally, as a result of making the decision to close the Sago mine, related development costs were deemed to be impaired and were written-off during 2008. No comparable impairment occurred during the prior year.

Table of Contents

Adjusted EBITDA by Operating Segment

Adjusted EBITDA represents net income before deducting interest expense, income taxes, depreciation, depletion, amortization, impairment charges and minority interest. Adjusted EBITDA is presented because it is an important supplemental measure of our performance used by our chief operating decision maker in such areas as capital investment and allocation of resources. It is considered "adjusted" as we adjust EBITDA for impairment charges and minority interest. Other companies in our industry may calculate Adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure. Adjusted EBITDA is reconciled to its most comparable GAAP measure on page 71 of this Annual Report on Form 10-K and in Note 20 to our consolidated financial statements for the year ended December 31, 2008.

The following table depicts operating segment Adjusted EBITDA for the years ended December 31, 2008 and 2007:

	Year ended December 31,		Increase (Decrease)	
	2008	2007	$	%
	(in thousands, except percentages)			
Central Appalachian	$ 107,186	$ 47,442	$ 59,744	126%
Northern Appalachian	23,687	(22,215)	45,902	207%
Illinois Basin	14,784	15,463	(679)	(4)%
Ancillary	(18,436)	18,363	(36,799)	(200)%
Total Adjusted EBITDA	$ 127,221	$ 59,053	$ 68,168	115%

Adjusted EBITDA from our Central Appalachian segment for the year ended December 31, 2008 increased compared to the year ended December 31, 2007 primarily due to a $24.6 million pre-tax gain on an exchange of coal reserves. The increase was further impacted by an increase of approximately 294,000 tons sold and an increase in profit margins of $2.74 per ton over prior year.

The increase in Adjusted EBITDA from our Northern Appalachian segment was due to a combination of an increase in sales realizations of $16.50 per ton, resulting in increased profit margins of $12.27 per ton, as well as an increase of approximately 646,000 tons sold.

Adjusted EBITDA from our Illinois Basin segment decreased during the year ended December 31, 2008 related to increases in operating costs with a less significant corresponding increase in sales realizations. The increased costs resulted in a decrease in profit margins of $1.44 per ton compared to the year ended December 31, 2007.

The decrease in Adjusted EBITDA from our Ancillary segment was primarily due to the gain on the sale of the Denmark property that occurred during 2007. Also, there was a decrease of approximately 675,000 tons sold related to the expiration of brokered coal contracts, partially offset by increased profit margins of $4.95 per ton.

Table of Contents

Reconciliation of Adjusted EBITDA to Net income (loss) by Operating Segment

The following tables reconcile Adjusted EBITDA to net income (loss) by operating segment for the years ended December 31, 2008 and 2007:

	Year ended December 31,		Increase (Decrease)	
	2008	2007	$	%
	(in thousands, except percentages)			
Central Appalachian				
Net income (loss)	$ 47,244	$ (184,372)	$ 231,616	126%
Depreciation, depletion and amortization	64,132	60,015	4,117	7%
Interest expense, net	2,145	1,397	748	54%
Income tax benefit	(6,335)	—	(6,335)	(100)%
Impairment loss	—	170,402	(170,402)	(100)%
Adjusted EBITDA	$ 107,186	$ 47,442	$ 59,744	126%

	Year ended December 31,		Increase (Decrease)	
	2008	2007	$	%
	(in thousands, except percentages)			
Northern Appalachian				
Net income (loss)	$ 3,217	$ (31,790)	$ 35,007	110%
Depreciation, depletion and amortization	17,884	9,467	8,417	89%
Interest expense, net	717	457	260	57%
Income tax benefit	(5,322)	—	(5,322)	(100)%
Impairment loss	7,191	—	7,191	100%
Minority interest	—	(349)	349	100%
Adjusted EBITDA	$ 23,687	$ (22,215)	$ 45,902	207%

	Year ended December 31,		Increase (Decrease)	
	2008	2007	$	%
	(in thousands, except percentages)			
Illinois Basin				
Net income	$ 6,959	$ 8,714	$ (1,755)	(20)%
Depreciation, depletion and amortization	7,342	6,527	815	12%
Interest expense, net	327	222	105	47%
Income tax expense	156	—	156	100%
Adjusted EBITDA	$ 14,784	$ 15,463	$ (679)	(4)%

	Year ended	Increase

	December 31,		(Decrease)	
	2008	2007	$	%
	(in thousands, except percentages)			
Ancillary				
Net income (loss)	$ (82,070)	$ 60,414	$ (142,484)	(236)%
Depreciation, depletion and amortization	6,689	10,508	(3,819)	(36)%
Interest expense, net	37,918	33,064	4,854	15%
Income tax benefit	(11,210)	(85,623)	74,413	87%
Impairment loss	30,237	—	30,237	100%
Adjusted EBITDA	$ (18,436)	$ 18,363	$ (36,799)	(200)%

	Year ended December 31,		Increase (Decrease)	
	2008	2007	$	%
	(in thousands, except percentages)			
Consolidated				
Net loss	$ (24,650)	$ (147,034)	$ 122,384	83%
Depreciation, depletion and amortization	96,047	86,517	9,530	11%
Interest expense, net	41,107	35,140	5,967	17%
Income tax benefit	(22,711)	(85,623)	62,912	73%
Impairment loss	37,428	170,402	(132,974)	(78)%
Minority interest	—	(349)	349	100%
Adjusted EBITDA	$ 127,221	$ 59,053	$ 68,168	115%

Table of Contents

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

Revenues

The following table depicts revenues for the years ended December 31, 2007 and 2006 for the indicated categories:

	Year ended December 31,		Increase (Decrease)	
	2007	2006	$ or Tons	%
	(in thousands, except percentages and per ton data)			
Coal sales revenues	$ 770,663	$ 833,998	$ (63,335)	(8)%
Freight and handling revenues	29,594	18,890	10,704	57%
Other revenues	48,898	38,706	10,192	26%
Total revenues	$ 849,155	$ 891,594	$ (42,439)	(5)%
Tons sold	18,343	19,371	(1,028)	(5)%
Coal sales revenue per ton	$ 42.01	$ 43.05	$ (1.04)	(2)%

Coal sales revenues. Coal sales revenues are derived from sales of produced coal and brokered coal contracts. Coal sales revenues decreased $63.3 million for the year ended December 31, 2007, or 8%, compared to 2006. This decrease was due to a 5% decrease in tons sold in 2007 compared to 2006 that resulted from a decrease of approximately 4.7 million tons sold related to the idling, closure or cutback of production at mines in 2007 as discussed below and the expiration of certain brokered coal contracts, as well as geologic issues at several other mines. The decrease in coal sales revenue from decreased sales tons was further impacted by a $1.04 per ton reduction in sales realization of our coal primarily sold pursuant to coal supply agreements. These decreases were partially offset by a 3.4 million ton increase in tons sold from new mines that commenced full production in 2007 and from mines that experienced a full year of production in 2007.

Freight and handling revenues. Freight and handling revenues represent dollar-for-dollar reimbursement for shipments from certain of our operations for which we initially pay the freight and handling costs and are then reimbursed by the customer. Freight and handling revenues and costs increased $10.7 million to $29.6 million for the year ended December 31, 2007 compared to 2006 due to an increase in shipments from locations operating under such agreements, as well as increased transportation rates and fuel surcharges.

Other revenues. Other revenues increased $10.2 million for the year ended December 31, 2007 compared to 2006. The increase was due to $6.8 million of revenue generated from coalbed methane wells owned jointly by our subsidiary, CoalQuest, and CDX, as well as increased revenue of $3.7 million from our highwall mining activities and shop services and $7.2 million from the sale of a narrow bench highwall mining system by ADDCAR. Partially offsetting these increases was a decrease in plant processing revenue of $1.1 million. Additionally, we recognized a $7.0 million gain in 2006 related to the termination of a contractual coal delivery obligation. No comparable gain was recognized in 2007.

Table of Contents

Coal sales revenues and tons sold by segment

The following table depicts coal sales revenues by operating segment for the years ended December 31, 2007 and 2006:

	Year ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Central Appalachian	$ 512,352	$ 534,429	$ (22,077)	(4)%
Northern Appalachian	121,200	109,184	12,016	11%
Illinois Basin	60,368	49,842	10,526	21%
Ancillary	76,743	140,543	(63,800)	(45)%
Total coal sales revenues	$ 770,663	$ 833,998	$ (63,335)	(8)%

The following table depicts tons sold by operating segment for the years ended December 31, 2007 and 2006:

	Year ended December 31,		Increase (Decrease)	
	2007	2006	Tons	%
	(in thousands, except percentages)			
Central Appalachian	11,323	10,904	419	4%
Northern Appalachian	3,291	3,281	10	*%
Illinois Basin	2,025	2,020	5	*%
Ancillary	1,704	3,166	(1,462)	(46)%
Total tons sold	18,343	19,371	(1,028)	(5)%

* Not meaningful

Coal sales revenues from our Central Appalachian segment decreased approximately $22.1 million, or 4%, for the year ended December 31, 2007 as compared to the year ended December 31, 2006. This decrease was primarily attributable to a decrease of $3.76 per ton in the average sales price of our coal primarily sold pursuant to coal supply agreements. The decrease in sales realization was partially offset by an increase in tons sold of approximately 0.4 million, or 4%, over 2006 due to various mines, principally at our Eastern and Raven locations, significantly increasing or reaching full production in 2007.

For the year ended December 31, 2007, our Northern Appalachian coal sales revenues increased approximately $12.0 million, or 11%, as compared to 2006 due to an increase in sales realization of $3.55 per ton as segment operations benefited from favorable pricing from its coal supply agreements, as well as an increase in sales of metallurgical coal at prevailing market prices. Tons sold from our Northern Appalachian operations remained constant as compared to the prior year.

Coal sales revenues from our Illinois Basin segment increased approximately $10.5 million, or 21%, as compared to 2006 due to an increase in coal sales revenue of $5.12 per ton resulting from more favorable terms on its coal supply agreements.

Our Ancillary segment's coal sales revenues are comprised of coal sold under brokered coal contracts. We experienced a decrease of $63.8 million, or 45%, due to a decrease of 1.5 million tons primarily resulting from the expiration of brokered coal contracts.

Table of Contents

Costs and expenses

The following table depicts cost of operations for the years ended December 31, 2007 and 2006 for the indicated categories:

	Year ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages and per ton data)			
Cost of coal sales	$ 732,112	$ 739,914	$ (7,802)	(1)%
Freight and handling costs	29,594	18,890	10,704	57%
Cost of other revenues	34,046	29,418	4,628	16%
Depreciation, depletion and amortization	86,517	72,218	14,299	20%
Selling, general and administrative expenses	33,325	34,578	(1,253)	(4)%
Net gain on sale of assets	(38,656)	(1,125)	(37,531)	*%
Goodwill impairment loss	170,402	—	170,402	100%
Total costs and expenses	$ 1,047,340	$ 893,893	$ 153,447	17%
Cost of coal sales per ton	$ 39.91	$ 38.20	$ 1.71	4%

* Not meaningful

Cost of coal sales. For the year ended December 31, 2007, our total cost of coal sales decreased $7.8 million, or 1%, to $732.1 million compared to $739.9 million for the year ended December 31, 2006. The decrease in cost of coal sales was primarily the result of a 5% decrease in tons sold as described above which was partially offset by a 4% increase in cost per ton.

Mining operations that significantly increased or reached full production in 2007 at our East Mac and Nellie, Flint Ridge Deep, Raven, Mt. Sterling, Guston Run, Crown Surface, Imperial, Sentinel, County Line and Middle Fork mines increased cost of coal sales by $144.0 million. Increased costs from new mining operations were partially offset by a decrease in costs of $111.9 million resulting from the closure or cutback of production at our higher cost Flint Ridge Surface, Rowdy Gap, Flint Ridge Highwall, Blackberry Creek, New Hill, Sago, Crown East II, Sycamore No. 1, Island, Tip Top and Elk Hollow mines. Cost of coal sales at existing mines, as well as from brokered coal contracts, decreased $40.5 million, primarily as a result of a 1.1 million ton decrease in coal sales.

Cost of coal sales per ton increased to $39.91 for the year ended December 31, 2007 compared to $38.20 in 2006, an increase of $1.71. The increase was mainly due to a $1.34 per ton increase in the average cost of produced coal sold. The increase in cost per ton of produced coal was caused by increases of: $0.46 per ton in labor and benefit costs; $0.27 per ton in contract labor; $0.44 per ton insurance and worker's compensation costs; $0.18 per ton in fuel, oil and lubricants; $0.26 per ton in blending material; $0.10 per ton in insurance; and $0.20 per ton in roof control supplies. The increases were partially offset by decreases of: $0.52 per ton in equipment and vehicle lease costs. Purchased coal increased $3.87 per ton, resulting in an increase of $0.38 per ton in the average cost of coal sold.

Cost of other revenues. For the year ended December 31, 2007, cost of other revenues increased $4.6 million, or 16%, to $34.0 million compared to $29.4 million for the year ended December 31, 2006. Of the increase, approximately $4.7 million was due to costs related to ADDCAR's sales of mining equipment during the year and exploration and

development of coalbed methane resulted in an additional increase of $1.8 million.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased $14.3 million, or 20%, to $86.5 million for the year ended December 31, 2007 compared to $72.2 million in 2006. The principal component of the increase was an increase in depreciation and amortization expense of $14.5 million for the year ended December 31, 2007 related to increased property and equipment purchased to improve efficiency at existing operations and to equip new mine developments. Additional increases in depreciation and amortization expense were due to coalbed methane well development costs of $5.5 million. The increases were partially offset by an increase in amortization income on below-market coal supply agreements of $5.7 million during the year ended December 31, 2007.

Selling, general and administrative expenses. Selling, general and administrative expenses for the year ended December 31, 2007 were $33.3 million compared to $34.6 million for the year ended December 31, 2006. The decrease of $1.3 million was primarily attributable to gifts aggregating $2.0 million made in 2006 to the families of the thirteen miners involved in the Sago mine accident, partially offset by an increase of $1.3 million in professional and legal fees.

Net gain on sale of assets. Net gain on sale of assets increased $37.5 million for the year ended December 31, 2007 from 2006, primarily due to a gain of approximately $36.8 million related to the sale of our Denmark property in the third quarter of 2007.

Goodwill impairment loss. The goodwill impairment loss reflects the negative impact of several contributing factors which resulted in a reduction in the forecasted cash flows used to estimate fair value. These factors include, but are not limited to, a significant decrease in the sales price of coal through our annual measurement date, increases in the cost of diesel fuel, explosives, tires, roofbolts and other materials used in mining coal, increased labor costs due to tightening labor markets, significant investments in the areas of safety and compliance and increased interest rates contributing to a higher discount rate. Furthermore, the business, regulatory and marketplace environments in which we currently operate differs significantly from the historical environments that drove the business cases used to value and record the acquisition of these business units. Accordingly, we have been unable to attain the forecasted projections that were used to initially value the business units at the date of acquisition. The goodwill impairment losses were at the following business units: $32.9 million at Hazard, $58.5 million at Eastern, $43.0 million at East Kentucky and $36.0 million at Knott County.

Table of Contents

Adjusted EBITDA by Segment

Adjusted EBITDA represents net income before deducting interest expense, income taxes, depreciation, depletion, amortization, impairment charges and minority interest. Adjusted EBITDA is presented because it is an important supplemental measure of our performance used by our chief operating decision maker in such areas as capital investment and allocation of resources. It is considered "adjusted" as we adjust EBITDA for impairment charges and minority interest. Adjusted EBITDA is calculated differently than the prior year in that it includes an adjustment for impairment charges. No impairment charges were incurred in the prior year. Other companies in our industry may calculate Adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure. Adjusted EBITDA is reconciled to its most comparable GAAP measure on page 76 of this Annual Report on Form 10-K and in Note 20 to our consolidated financial statements for the year ended December 31, 2007.

The following table depicts segment Adjusted EBITDA for the years ended December 31, 2007 and 2006:

	Year ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Central Appalachian	$ 47,442	$ 108,598	$ (61,156)	(56)%
Northern Appalachian	(22,215)	(36,586)	14,371	39%
Illinois Basin	15,463	4,476	10,987	245%
Ancillary	18,363	(4,456)	22,819	512%
Total Adjusted EBITDA	$ 59,053	$ 72,032	$ (12,979)	(18)%

Adjusted EBITDA from our Central Appalachian segment decreased $61.2 million, or 56%, for the year ended December 31, 2007 as compared to the year ended December 31, 2006. The decrease was primarily due to the decreased realization per ton as discussed above. Also impacting the decrease were inflated operating costs per ton primarily resulting from regulatory issues and short-term mine constraints. The reduced realizations and increased costs resulted in a decrease in profit margins of $5.99 per ton. Additionally, activities incidental to our coal producing activities decreased by $1.5 million in 2007 further contributing to the decrease in Adjusted EBITDA.

The increase in Adjusted EBITDA from our Northern Appalachian segment of $14.4 million for the year ended December 31, 2007 was primarily due to an increase in coal sales revenue as of $3.55 per ton and decreased costs of $1.02 per ton resulting in increased profit margins of $4.57 per ton.

Adjusted EBITDA from our Illinois Basin segment increased $11.0 million during the year ended December 31, 2007 due to a $5.12 per ton increase in sales realization over 2006 with cost per ton remaining constant with prior year.

The increase in Adjusted EBITDA from our Ancillary segment of $22.8 million was primarily due to the sale of the Denmark property in September 2007, which resulted in a gain of $36.8 million, as well as from increased contributions to income from our investment in coalbed methane wells and from our ADDCAR subsidiary as discussed above. These increases were partially offset by a decrease in Adjusted EBITDA resulting from the expiration of brokered coal contracts.

Table of Contents

Reconciliation of Adjusted EBITDA to Net income (loss) by Segment

The following tables reconcile Adjusted EBITDA to net income (loss) by segment for the years ended December 31, 2007 and 2006:

	Year ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Central Appalachian				
Net income (loss)	$ (184,372)	$ 59,620	$ (243,992)	(409)%
Depreciation, depletion and amortization	60,015	48,050	11,965	25%
Interest expense, net	1,397	928	469	51%
Impairment loss	170,402	—	170,402	100%
Adjusted EBITDA	$ 47,442	$ 108,598	$ (61,156)	(56)%

	Year ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Northern Appalachian				
Net loss	$ (31,790)	$ (47,907)	$ 16,117	34%
Depreciation, depletion and amortization	9,467	10,822	(1,355)	(13)%
Interest expense, net	457	441	16	4%
Minority interest	(349)	58	(407)	(702)%
Adjusted EBITDA	$ (22,215)	$ (36,586)	$ 14,371	39%

	Year ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Illinois Basin				
Net income (loss)	$ 8,714	$ (1,978)	$ 10,692	541%
Depreciation, depletion and amortization	6,527	6,287	240	4%
Interest expense, net	222	167	55	33%
Adjusted EBITDA	$ 15,463	$ 4,476	$ 10,987	245%

	Year ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Ancillary				
Net income (loss)	$ 60,414	$ (19,055)	$ 79,469	417%

Depreciation, depletion and amortization	10,508	7,059	3,449	49%
Interest expense, net	33,064	16,555	16,509	100%
Income tax benefit	(85,623)	(9,015)	(76,608)	(850)%
Adjusted EBITDA	$ 18,363	$ (4,456)	$ 22,819	512%

	Year ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Consolidated				
Net loss	$ (147,034)	$ (9,320)	$ (137,714)	*%
Depreciation, depletion and amortization	86,517	72,218	14,299	20%
Interest expense, net	35,140	18,091	17,049	94%
Income tax benefit	(85,623)	(9,015)	(76,608)	(850)%
Impairment loss	170,402	—	170,402	100%
Minority interest	(349)	58	(407)	(702)%
Adjusted EBITDA	$ 59,053	$ 72,032	$ (12,979)	(18)%

* Not meaningful

Table of Contents

Liquidity and Capital Resources

Our business is capital intensive and requires substantial capital expenditures for, among other things, purchasing and upgrading equipment used in developing and mining our coal lands, as well as remaining in compliance with environmental laws and regulations. Our principal liquidity requirements are to finance our coal production, fund capital expenditures and service our debt and reclamation obligations. We may also engage in acquisitions from time to time. Our primary sources of liquidity to meet these needs are cash flows from sales of our coal, other income, borrowings under our senior credit facility, the proceeds of our convertible notes offering and capital equipment financing arrangements.

We believe the principal indicators of our liquidity are our cash position and remaining availability under our credit facility. As of December 31, 2008, our available liquidity was $90.3 million, including cash of $63.9 million and $26.4 million available for borrowing under our $100.0 million senior credit facility. Total debt represented 48% of our total capitalization at December 31, 2008. Our total capitalization represents our current and long-term debt combined with our total stockholders' equity.

In February 2009, we executed an amendment to our $100.0 million credit facility that affected certain 2009 debt covenants. The amendment modified the maximum permitted leverage and minimum interest coverage ratios. The amendment also decreased the maximum capital spending and added a minimum liquidity requirement. Debt covenants for years subsequent to 2009 were not affected by the amendment.

The recent and unprecedented disruption in the current credit markets has had a significant adverse impact on a number of financial institutions. At this time, our liquidity has not been materially impacted by the current credit environment and we do not expect that it will be materially impacted in the near-future. We will continue to closely monitor our liquidity and the credit markets. However, we cannot predict with any certainty the impact to us of any further disruption in the credit environment. See "Risk Factors – The duration or severity of the current global financial crisis are uncertain and may have an impact on our business and financial conditions in ways that we currently cannot predict."

Our Convertible Senior Notes (the "Convertible Notes") became convertible at the option of holders beginning July 1, 2008. The conversion period expired on September 30, 2008 pursuant to the terms of the governing indenture with no holders exercising their conversion rights. The Convertible Notes may become convertible again in the future under certain conditions. Accordingly, we will reassess the convertibility on a quarterly basis.

We currently expect our total capital expenditures will be approximately $100.0 million in 2009, substantially all of which will be for equipment and infrastructure at our existing operations. Cash paid for capital expenditures was approximately $132.0 million for the year ended December 31, 2008. We have funded and will continue to fund these capital expenditures from our internal operations and with proceeds from our convertible notes offering in 2007. We believe that these sources of capital and our $50.0 million equipment revolving credit facility with Caterpillar Financial Services Corporation will be sufficient to fund our anticipated capital expenditures under our current budget plan through the end of 2009. Although we expect to experience some periods of tightening liquidity availability, we expect to be able to manage through such periods. To the extent necessary, management believes it has flexibility in the timing of the cash requirements by managing the pace of capital spending. In addition, management may from time to time raise additional capital through the disposition of non-core assets or engaging in sale-leaseback transactions. The need and timing of seeking additional capital in the future will be subject to market conditions.

Approximately $85.5 million of 2008 cash paid for capital expenditures was attributable to Central Appalachian operations. This amount represents investments of approximately $44.1 million in our Beckley mining complex, as

well as additional investments of $41.4 million for upgrades at the remaining Central Appalachian operations. We paid approximately $30.8 million at our Northern Appalachian operations in the year ended December 31, 2008, approximately $20.6 million of which was for development of our Sentinel and Tygart properties. Expenditures of approximately $4.9 million for our Illinois Basin operations were for ongoing operations improvements. Approximately $10.8 million of cash paid for capital expenditures for the year ended December 31, 2008 was within our Ancillary segment for safety equipment, as well as for upgrades at various other subsidiaries.

As a result of recent accidents in the mining industry, additional regulatory requirements were promulgated that will require additional capital expenditures to meet enhanced safety standards. For the year ended December 31, 2008, we spent $4.2 million to meet these standards and anticipate spending an additional $4.3 million in 2009.

Table of Contents

Cash Flows

Net cash provided by operating activities was $78.0 million for the year ended December 31, 2008, an increase of $55.9 million from the same period in 2007. This increase is attributable to a decrease in net loss of $63.2 million after adjustment for non-cash charges offset by a decrease in net operating assets and liabilities of $7.3 million.

For the year ended December 31, 2008, net cash used in investing activities was $123.3 million compared to $126.5 million for the year ended December 31, 2007. For the year ended December 31, 2008, $132.0 million of cash was used for development and acquisition of new mining complexes and to support existing mining operations compared to $169.3 million in the same period 2007. Additionally, we collected proceeds from asset sales of $8.8 million during the year ended December 31, 2008 versus $46.5 million during the comparable period of 2007.

Net cash used by financing activities of $2.1 million for the year ended December 31, 2008 was due to repayments on our short-term and long-term debt of $7.9 million. These amounts were partially offset by borrowings of $9.8 million provided by long-term and short-term notes entered into during the year and proceeds from stock options exercised of $0.1 million.

Net cash provided by operating activities was $22.1 million for the year ended December 31, 2007, a decrease of $33.5 million from 2006. This decrease is attributable to an increase in net operating assets and liabilities of $41.1 million offset by a decrease in net loss of $74.6 million after adjustment for non-cash charges.

For the year ended December 31, 2007, net cash used in investing activities was $126.5 million compared to $160.8 million for the year ended December 31, 2006. For 2007, $169.3 million of cash was used to support existing mining operations and for development of new mining complexes compared to $165.7 million in 2006. Investing activities for 2007 also included cash paid of $3.8 million representing contingency payments related to the Horizon acquisition as compared to $4.7 million in 2006. Additionally, we collected proceeds from asset sales of $46.5 million during the year ended December 31, 2007 versus $3.8 million during 2006.

Net cash provided by financing activities of $192.8 million for the year ended December 31, 2007 was primarily due to proceeds of $225.0 million from our convertible senior notes offering. Additionally, we had borrowings of $65.0 million on our credit facility and an additional $26.1 million was provided by short-term notes entered into during the year. These borrowings were offset by repayments on our short-term and long-term debt and capital leases of $45.4 million and $68.6 million, respectively. Also impacting financing activities for the year ended December 31, 2007 was additional finance costs of $9.3 million related to the issuance of our convertible notes and amending our credit facility.

Credit Facility and Long-Term Debt Obligations

As of December 31, 2008, our total long-term indebtedness, including capital lease obligations, consisted of the following (in thousands):

	2008
9.00% Convertible senior notes, due 2012	$ 225,000
10.25% Senior notes, due 2014	175,000
Equipment notes	43,378
Capital leases	3,817
Insurance notes	3,044
Total	450,239

Less current portion	15,319
Long-term debt	$ 434,920

Convertible senior notes. In 2007, we completed a private offering of $225.0 million aggregate principal amount of 9.00% Convertible Senior Notes (the “Convertible Notes”) due 2012. The Convertible Notes are our senior unsecured obligations and are guaranteed on a senior unsecured basis by our material future and current domestic subsidiaries. The Convertible Notes and the related guarantees rank equal in right of payment to all of our and the guarantors’ respective existing and future unsecured senior indebtedness. Interest is payable semi-annually in arrears on February 1 and August 1 of each year.

The Convertible Notes became convertible at the option of holders beginning July 1, 2008. The conversion period expired on September 30, 2008 pursuant to the terms of the governing indenture with no holders exercising their conversion rights. The Convertible Notes may become convertible again in the future under certain conditions. Accordingly, we will reassess the convertibility on a quarterly basis.

Table of Contents

The principal amount of the Convertible Notes is payable in cash and amounts above the principal amount, if any, will be convertible into shares of our common stock or, at our option, cash. The Convertible Notes are convertible at an initial conversion price, subject to adjustment, of $6.10 per share (approximating 163.8136 shares per one thousand dollar principal amount of the Convertible Notes). The volume weighted-average price of our stock subsequent to the expiration date of the conversion period was below $6.10 per share. Accordingly, there were no potentially convertible shares at December 31, 2008. The Convertible Notes are convertible upon the occurrence of certain events, including (i) prior to February 12, 2012 during any calendar quarter after September 30, 2007, if the closing sale price per share of our 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; (ii) prior to February 12, 2012 during the five consecutive business days immediately after any five consecutive trading day period in which the average trading price for the notes on each day during such five trading-day period was equal to or less than 97% of the closing sale price of our common stock on such day multiplied by the then current conversion rate; (iii) upon the occurrence of specified corporate transactions; and (iv) at any time from, and including February 1, 2012 until the close of business on the second business day immediately preceding August 1, 2012. In addition, upon events defined as a “fundamental change” under the Convertible Notes indenture, we may be required to repurchase the Convertible Notes at a repurchase price in cash equal to 100% of the principal amount of the notes to be repurchased, plus any accrued and unpaid interest to, but excluding, the fundamental change repurchase date. As such, in the event of a fundamental change or the aforementioned average pricing thresholds are met, we would be required to classify the entire amount outstanding of the Convertible Notes as a current liability in the following quarter. In the event that a significant number of the holders of the Convertible Notes were to convert their notes prior to maturity, we may not have enough available funds at any particular time to make the required repayments. Under these circumstances, we would look to WLR, our banking group and other potential lenders to obtain short-term funding until such time that we could secure necessary financing on a long-term basis. The availability of any such financing would depend upon the circumstances at the time, including the terms of any such financing, and other factors. In addition, if conversion occurs in connection with certain changes in control, we may be required to deliver additional shares of our common stock (a “make whole” premium) by increasing the conversion rate with respect to such notes.

Senior notes. In 2006, we sold $175.0 million aggregate principal amount of our 10.25% Senior Notes (the “Notes”) due July 15, 2014. Interest on the Notes is payable semi-annually in arrears on July 15 and January 15 of each year. The Notes are senior unsecured obligations and are guaranteed on a senior unsecured basis by all of our current and future domestic subsidiaries that are material or that guarantee our amended and restated credit facility. The Notes and the guarantees rank equally with all of our and the guarantors’ existing and future senior unsecured indebtedness, 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 that indebtedness and to all liabilities of our subsidiaries that are not guarantors. We have the option to redeem all or a portion of the Notes at 100% of the aggregate principal amount at maturity at any time on or after July 15, 2010. At any time prior to July 15, 2010, we may also redeem all or a portion of the Notes at a redemption price equal to 100% of the aggregate principal amount of the Notes plus an applicable premium as of, and accrued and unpaid interest and additional interest, if any, to, but not including the date of redemption. At any time before July 15, 2009, we may also redeem up to 35% of the aggregate principal amount of the Notes at a redemption price of 110.25% of the principal amount, plus accrued and unpaid interest, if any, to the date of redemption, with the proceeds of certain equity offerings. Upon a change of control, we may be required to offer to purchase the Notes at a purchase price equal to 101% of the principal amount, plus accrued and unpaid interest.

The indenture governing the Notes contains covenants that limit our ability to, among other things, incur additional indebtedness, issue preferred stock, pay dividends, repurchase, repay or redeem our capital stock, make certain investments, sell assets and incur liens. As of December 31, 2008, we were in compliance with our covenants under the indenture.

Credit facility. In 2006, we entered into a second amended and restated credit agreement (the "Amended Credit Facility") consisting of a revolving credit facility which matures on June 23, 2011. In July 2007, concurrent with the issuance of the convertible notes, we further amended the Amended Credit Facility to reduce the commitments thereunder to $100.0 million, of which a maximum of $80.0 million may be used for letters of credit. The amendment, among other things, modified the maximum permitted leverage ratio, the minimum interest coverage ratio and the maximum amount of capital expenditures permitted. Further, the amendment revised certain interest rate thresholds and unused commitment fee levels under the Amended Credit Facility. In February 2009, we executed a further amendment to the Amended Credit Facility that affected certain 2009 debt covenants. The amendment modified the maximum permitted leverage and minimum interest coverage ratios. The amendment also decreased the maximum capital spending and added a minimum liquidity requirement. Debt covenants for years subsequent to 2009 were not affected by the amendment. As of December 31, 2008, we had no borrowings outstanding and letters of credit totaling $73.6 million outstanding, leaving $26.4 million available for future borrowing capacity. Interest on the borrowings under the Amended Credit Facility is payable, at our option, at either the base rate plus an applicable margin based on our leverage ratio of 1.25% to 2.00% as of December 31, 2008 or LIBOR plus an applicable margin based on our leverage ratio of 2.25% to 3.00% as of December 31, 2008. As of December 31, 2008, we were in compliance with our financial covenants under the Amended Credit Facility.

Equipment notes and other. The equipment notes, having various maturity dates extending to January 2014, are collateralized by mining equipment. As of December 31, 2008, we had amounts outstanding for 36-month through 60-month terms with a weighted-average interest rate of 6.42%. At December 31, 2008, additional funds are available under our revolving equipment credit facility for terms ranging from 36 to 60 months with a current interest rate of 8.75%. Additionally, we finance certain of our annual insurance premiums at a current interest rate of 5.42%.

Table of Contents

Other

As a regular part of our business, we review opportunities for, and engage in discussions and negotiations concerning, the acquisition of coal mining assets and interests in coal mining companies, and acquisitions of, or combinations with, coal mining companies. When we believe that these opportunities are consistent with our growth plans and our acquisition criteria, we will make bids or proposals and/or enter into letters of intent and other similar agreements, which may be binding or nonbinding, that are customarily subject to a variety of conditions and usually permit us to terminate the discussions and any related agreement if, among other things, we are not satisfied with the results of our due diligence investigation. Any acquisition opportunities we pursue could materially affect our liquidity and capital resources and may require us to incur indebtedness, seek equity capital or both. There can be no assurance that additional financing will be available on terms acceptable to us, or at all.

Additionally, we have other long-term liabilities, including, but not limited to, mine reclamation and mine closure costs, below-market coal supply agreements and “black lung” costs, and some of our subsidiaries have long-term liabilities relating to retiree health and other employee benefits.

Our ability to meet our long-term debt obligations will depend upon our future performance, which, in turn, will depend upon general economic, financial and business conditions, along with competition, legislation and regulation—factors that are largely beyond our control. Based upon our current operations, we believe that cash flow from operations, together with other available sources of funds will be adequate for at least through the end of 2009 for making required payments of principal and interest on our indebtedness and for funding anticipated capital expenditures and working capital requirements. Although we expect to experience some periods of tightening liquidity availability, we expect to be able to manage through such periods. To the extent necessary, management believes it has flexibility in the timing of the cash requirements by managing the pace of capital spending. In addition, management may from time to time raise additional capital through the disposition of non-core assets or engaging in sale-leaseback transactions. However, we cannot assure you that our operating results, cash flow and capital resources will be sufficient for repayment of our debt obligations in the future.

Contractual Obligations

The following is a summary of our significant future contractual obligations by year as of December 31, 2008 (in thousands):

	Payments due by period				
	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Long-term debt, capital lease and other obligations(1)	$ 57,990	$ 101,104	$ 286,703	$ 184,785	$ 630,582
Operating leases	87	82	—	—	169
Coal purchase obligations(2)	22,926	14,377	—	—	37,303
Diesel fuel purchase obligations(2)	73,753	—	—	—	73,753
Advisory Services Agreement(3)	2,000	3,500	—	—	5,500
Minimum royalties	10,111	19,640	16,636	37,004	83,391
Postretirement medical benefits	523	2,505	5,068	170,230	178,326
Total	$ 167,390	$ 141,208	$ 308,407	$ 392,019	$ 1,009,024

(1) Amounts are inclusive of interest assuming interest rates of 10.25% for our senior notes, 9.0% for our convertible notes and ranging from 5.10% to 8.75% on our equipment notes.
(2) Reflects estimates of obligations.
(3) See "Certain relationships and related party transactions."

We have excluded from the table above uncertain tax liabilities as defined in FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," due to the immateriality of such amounts.

Table of Contents

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. No liabilities related to these arrangements are reflected in our consolidated balance sheets and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

Federal and state laws require us to secure payment of certain long-term obligations, such as mine closure and reclamation costs, federal and state workers' compensation, coal leases and other obligations. We typically secure these payment obligations by using surety bonds, an off-balance sheet instrument. The use of surety bonds is less expensive than posting an all cash bond or a bank letter of credit, either of which would require a greater use of our credit facility. We then use bank letters of credit to secure our surety bonding obligations as a lower cost alternative than securing those bonds with cash. We currently have a $130.4 million committed bonding facility pursuant to which we are required to provide bank letters of credit in an amount up to 50% of the aggregate bond liability. Recently, surety bond costs have increased, while the market terms of surety bonds have generally become less favorable. To the extent that surety bonds become unavailable, we would seek to secure our reclamation obligations with letters of credit, cash deposits or other suitable forms of collateral.

As of December 31, 2008, we had outstanding surety bonds with third parties for post-mining reclamation totaling $111.0 million, plus $4.7 million for miscellaneous purposes. As of December 31, 2008, we maintained letters of credit totaling $73.6 million to secure reclamation surety bonds and other obligations.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on results of operations for the years ended December 31, 2008, 2007 and 2006. However, commodities prices have increased at a rate greater than that of the general economy, specifically prices for fuel and explosives, steel products, tires, healthcare and labor.

Recent Accounting Pronouncements

Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements ("SFAS No. 157"). SFAS No. 157 clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. Adoption of SFAS No. 157 did not have a material impact on our financial position, results of operations or cash flows; however, adoption did result in additional information being included in the footnotes accompanying our consolidated financial statements.

In February 2008, the FASB issued FSP 157-2, Effective Date of FASB Statement No. 157 ("FSP 157-2"). FSP 157-2 permits delayed adoption of SFAS No. 157 for certain non-financial assets and liabilities, which are not recognized at fair value on a recurring basis, until fiscal years, and interim periods within those fiscal years, beginning after November 15, 2008. Adoption of FSP 157-2 did not have a material impact on our financial position, results of operations or cash flows.

Fair Value Option. In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115 ("SFAS No. 159"). SFAS No. 159 provides entities with an option to report selected financial assets and liabilities at fair value and establishes

presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Adoption of SFAS No. 159 did not have a material impact on our financial position, results of operations or cash flows.

Financial Assets. In October 2008, the FASB issued FSP 157-3, Determining Fair Value of a Financial Asset in a Market That Is Not Active ("FSP 157-3"). FSP 157-3 clarified the application of SFAS No. 157 in an inactive market. It demonstrated how the fair value of a financial asset is determined when the market for that financial asset is inactive. FSP 157-3 was effective upon issuance, including prior periods for which financial statements had not been issued. Adoption of FSP 157-3 did not have a material impact on our financial position, results of operations or cash flows.

Table of Contents

Convertible Debt. In May 2008, the FASB issued FSP APB 14-1, Accounting for Convertible Debt Instruments That May be Settled in Cash Upon Conversion (Including Partial Cash Settlement) ("FSP APB 14-1"). FSP APB 14-1 requires the liability and equity components of convertible debt instruments that may be settled in cash upon conversion to be separately accounted for in a manner that reflects the issuer's nonconvertible debt borrowing rate. To allocate the proceeds from a convertible debt offering in this manner, a company would first need to determine the carrying amount of the liability component, which would be based on the fair value of a similar liability (excluding any embedded conversion options). The resulting debt discount would be amortized over the period during which the debt is expected to be outstanding as additional non-cash interest expense. FSP APB 14-1 is effective for financial statements for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years, and would be applied retrospectively for all periods presented. We have determined our non-convertible borrowing rate would have been 11.7% at issuance. The expected effect of adoption of FSP APB 14-1 is as follows:

	2008	2007
Property, plant, equipment and mine development	$ 1,151	$ 376
Debt issuance costs, net	(173)	(576)
Total assets	$ 978	$ (200)
Long-term debt and capital leases	$ (17,369)	$ (21,082)
Deferred tax liability	6,935	7,893
Total liabilities	(10,434)	(13,189)
Paid-in-capital	13,517	13,517
Retained deficit	(2,105)	(528)
Total stockholders' equity	11,412	12,989
Total liabilities and stockholders' equity	$ 978	$ (200)
Interest expense, net	$ (2,536)	$ (849)
Income tax benefit	959	321
Net loss	$ (1,577)	$ (528)

Business Combinations. In December 2007, the FASB issued SFAS No. 141 (Revised 2007), Business Combinations ("SFAS No. 141(R)"). SFAS No. 141(R) will significantly change the accounting for business combinations. Under SFAS No. 141(R), an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions. SFAS No. 141(R) will change the accounting treatment for certain specific acquisition-related items including: (i) expensing acquisition-related costs as incurred, (ii) valuing noncontrolling interests at fair value at the acquisition date and (iii) expensing restructuring costs associated with an acquired business. SFAS No. 141(R) also includes a substantial number of new disclosure requirements. SFAS No. 141(R) is to be applied to any business combination for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Upon adoption, SFAS No. 141(R) will impact the accounting for our future business combinations.

Noncontrolling Interests. In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements ("SFAS No. 160"). SFAS No. 160 establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary (minority interest) is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements and separate from the parent company's equity. Among other requirements, this statement requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the

consolidated statement of operations, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. We are currently evaluating the effect, if any, that the adoption of SFAS No. 160 will have on our financial position, results of operations and cash flows.

Table of Contents

Derivative Instruments. In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133 ("SFAS No. 161"). SFAS No. 161 requires additional disclosures for derivative instruments and hedging activities that include how and why an entity uses derivatives, how these instruments and the related hedged items are accounted for under FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and related interpretations and how derivative instruments and related hedged items affect the entity's financial position, results of operations and cash flows. SFAS No. 161 is effective for fiscal years, and interim periods within those fiscal years, beginning after November 15, 2008. Adoption of SFAS No. 161 did not impact the footnotes accompanying our consolidated financial statements.

GAAP Hierarchy. In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles ("SFAS No. 162"). SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles. SFAS No. 162 directs the hierarchy to the entity, rather than the independent auditors, as the entity is responsible for selecting accounting principles for financial statements that are presented in conformity with generally accepted accounting principles. SFAS No. 162 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008. Adoption of SFAS No. 162 did not have a material impact on our financial position, results of operations or cash flows.

Share-Based Payments. In June 2008, the FASB issued EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities ("EITF 03-6-1"). EITF 03-6-1 clarifies that all outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders. Awards of this nature are considered participating securities and the two-class method of computing basic and diluted earnings per share must be applied. EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. Adoption of EITF 03-6-1 did not have a material impact on our financial position, results of operations or cash flows.

Financial Instruments. In June 2008, the FASB ratified EITF 07-5, Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity's Own Stock ("EITF 07-5"). EITF 07-5 provides that an entity should use a two step approach to evaluate whether an equity-linked financial instrument (or embedded feature) is indexed to its own stock, including evaluating the instrument's contingent exercise and settlement provisions. It also clarifies the impact of foreign currency denominated strike prices and market-based employee stock option valuation instruments on the evaluation. EITF 07-5 is effective for fiscal years beginning after December 15, 2008. Adoption of EITF 07-5 did not have a material impact on our financial position, results of operations or cash flows.

Table of Contents

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest rate risk. In May 2006, we entered into an Interest Rate Collar Agreement, which became effective on March 31, 2007 and expires March 31, 2009, to hedge our interest risk on $200.0 million notional amount of revolving debt. The interest rate collar is designed as a cash flow hedge to offset the impact of changes in the LIBOR interest rate above 5.92% and below 4.80%. This agreement was entered into in conjunction with our amended and restated credit facility dated June 23, 2006. We recognize the change in the fair value of this agreement in the income statement in the period of change. For the year ended December 31, 2008, we recorded a loss of $2.0 million related to changes in fair market value.

Market price risk. We are exposed to market price risk in the normal course of mining and selling coal. As of December 31, 2008, 92% of 2009 planned production is committed for sale, leaving approximately 8% uncommitted for sale. A hypothetical decrease of $1.00 per ton in the market price for coal would reduce pre-tax income by approximately $1.5 million for 2009.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our financial statements and supplementary data are included at the end of this report beginning on page F-1.

Table of Contents

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

We maintain a set of disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934 (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. Our disclosure controls and procedures are also designed to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. Periodically, we review the design and effectiveness of our disclosure controls and controls over financial reporting to ensure they remain effective. If such reviews identify a need, we will make modifications to improve the design and effectiveness of our control structure.

Control systems, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that control objectives are met. Because of inherent limitations in all control systems, no evaluation of controls can provide assurance that all control issues and instances of fraud, if any, within a company will be detected. Additionally, controls can be circumvented by individuals, by collusion of two or more people, or by management override. Over time, controls can become inadequate because of changes in conditions or the degree of compliance may deteriorate. Further, the design of any system of controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any design will succeed in achieving its stated goals under all future conditions. Because of the inherent limitations in any cost-effective control system, misstatements due to errors or fraud may occur and not be detected.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for maintaining and establishing adequate internal control over financial reporting. Our internal control framework and processes were designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Because of inherent limitations, any system of 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.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of our controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control—Integrated Framework. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our controls and procedures were effective as of December 31, 2008.

Our Independent Registered Public Accounting Firm, Deloitte & Touche LLP, has audited the effectiveness of our internal control over financial reporting, as stated in their attestation report included on page F-1 of Item 15.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal controls over financial reporting during the fourth quarter of fiscal year 2008 that would have materially affected, or would be reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

Part III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information requested by Items 401, 405 and 406 of Regulation S-K is incorporated herein by reference to the definitive Proxy Statement used in connection with the solicitation of proxies for our Annual Meeting of Stockholders to be held on May 20, 2009 (the "Definitive Proxy Statement").

ITEM 11. EXECUTIVE COMPENSATION

The information requested by Item 402 of Regulation S-K is incorporated herein by reference to the Definitive Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information requested by Item 403 of Regulation S-K is incorporated herein by reference to the Definitive Proxy Statement.

See "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Summary of Equity Compensation Plans" on page 57 of this Annual Report on Form 10-K for information required by Item 201(d) of Regulation S-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information requested by Item 404 of Regulation S-K is incorporated herein by reference to the Definitive Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICE

The information with respect to the fees and services related to our independent registered public accounting firm, Deloitte & Touche LLP, and the disclosure of the Audit Committee's pre-approval policies and procedures are contained in the Definitive Proxy Statement and will be incorporated herein by reference.

Table of Contents

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements:

The following financial statements are filed as part of this Annual Report on Form 10-K under Item 8:

	Page
International Coal Group, Inc. and Subsidiaries	
Reports of Independent Registered Public Accounting Firm	F-1
Consolidated Balance Sheets as of December 31, 2008 and 2007	F-3
Consolidated Statements of Operations for the years ended December 31, 2008, 2007 and 2006	F-4
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2008, 2007 and 2006	F-5
Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006	F-6
Notes to Consolidated Financial Statements for the years ended December 31, 2008, 2007 and 2006	F-7
(b) Exhibits.	
(i) See the Exhibit Index.	
(c) Financial Statement Schedules.	

	Page
Schedule I—Condensed Financial Information of the Registrant	F-34
Schedule II—Valuation and Qualifying Accounts	F-38

Schedules other than that noted above are omitted because of an absence of conditions under which they are required or because the information to be disclosed is presented in the financial statements or notes thereto.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
International Coal Group, Inc.
Scott Depot, West Virginia

We have audited the internal control over financial reporting of International Coal Group, Inc. and subsidiaries (the "Company") as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The 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's 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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2008 of the Company and our report dated February 27, 2009 expressed an unqualified opinion on those financial

statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Cincinnati, Ohio
February 27, 2009

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
International Coal Group, Inc.
Scott Depot, West Virginia

We have audited the accompanying consolidated balance sheets of International Coal Group, Inc. and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules 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, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Cincinnati, Ohio
February 27, 2009

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
December 31, 2008 and 2007
(Dollars in thousands, except per share amounts)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 63,930	$ 107,150
Accounts receivable, net of allowances of $1,516 and $539	75,321	83,765
Inventories, net	58,788	40,679
Deferred income taxes	17,649	5,000
Prepaid insurance	13,380	10,618
Income taxes receivable	8,030	8,854
Prepaid expenses and other	10,893	9,138
Total current assets	247,991	265,204
PROPERTY, PLANT, EQUIPMENT AND MINE DEVELOPMENT, net	1,068,146	974,334
DEBT ISSUANCE COSTS, net	10,635	13,466
ADVANCE ROYALTIES, net	17,462	14,661
GOODWILL	—	30,237
OTHER NON-CURRENT ASSETS	5,435	5,661
Total assets	$ 1,349,669	$ 1,303,563
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 75,810	$ 70,042
Short-term debt	4,741	—
Current portion of long-term debt and capital leases	15,319	4,234
Current portion of reclamation and mine closure costs	11,139	7,333
Current portion of employee benefits	3,359	2,925
Accrued expenses and other	87,704	62,723
Total current liabilities	198,072	147,257
LONG-TERM DEBT AND CAPITAL LEASES	434,920	408,096
RECLAMATION AND MINE CLOSURE COSTS	68,107	78,587
EMPLOYEE BENEFITS	61,194	55,132
DEFERRED INCOME TAXES	42,468	52,355
BELOW-MARKET COAL SUPPLY AGREEMENTS	43,888	39,668
OTHER NON-CURRENT LIABILITIES	6,195	8,062
Total liabilities	854,844	789,157
MINORITY INTEREST	35	35

COMMITMENTS AND CONTINGENCIES	—	—
STOCKHOLDERS' EQUITY:		
Preferred stock – par value $0.01, 200,000,000 shares authorized, none issued	—	—
Common stock – par value $0.01, 2,000,000,000 shares authorized, 153,322,245 and 152,992,109 shares, respectively, issued and outstanding	1,533	1,530
Additional paid-in capital	643,480	639,160
Accumulated other comprehensive loss	(5,157)	(5,903)
Retained deficit	(145,066)	(120,416)
Total stockholders' equity	494,790	514,371
Total liabilities and stockholders' equity	$ 1,349,669	$ 1,303,563

See notes to consolidated financial statements.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
Years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

	Year Ended December 31,		
	2008	2007	2006
REVENUES:			
Coal sales revenues	$ 998,245	$ 770,663	$ 833,998
Freight and handling revenues	45,231	29,594	18,890
Other revenues	53,260	48,898	38,706
Total revenues	1,096,736	849,155	891,594
COSTS AND EXPENSES:			
Cost of coal sales	882,983	732,112	739,914
Freight and handling costs	45,231	29,594	18,890
Cost of other revenues	35,672	34,046	29,418
Depreciation, depletion and amortization	96,047	86,517	72,218
Selling, general and administrative	38,147	33,325	34,578
Gain on sale of assets	(32,518)	(38,656)	(1,125)
Goodwill impairment loss	30,237	170,402	—
Long-lived asset impairment loss	7,191	—	—
Total costs and expenses	1,102,990	1,047,340	893,893
Loss from operations	(6,254)	(198,185)	(2,299)
INTEREST AND OTHER INCOME (EXPENSE):			
Interest expense, net	(41,107)	(35,140)	(18,091)
Other, net	—	319	2,113
Total interest and other income (expense)	(41,107)	(34,821)	(15,978)
Loss before income taxes and minority interest	(47,361)	(233,006)	(18,277)
INCOME TAX BENEFIT	22,711	85,623	9,015
MINORITY INTEREST	—	349	(58)
Net loss	$ (24,650)	$ (147,034)	$ (9,320)
Earnings per share:			
Basic and diluted	$ (0.16)	$ (0.97)	$ (0.06)
Weighted-average common shares outstanding:			
Basic and diluted	152,632,586	152,304,461	152,028,165

See notes to consolidated financial statements.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Years ended December 31, 2008, 2007 and 2006
(Dollars in thousands)

	Common Stock		Additional Paid-in Capital	Unearned Compensation Restricted Stock	Accumulated Other Comprehensive Income	Retained Earnings (Deficit)	Total
	Shares	Amount					
Balance—December 31, 2005	152,321,908	$ 1,523	$ 632,897	$ (4,622)	$ —	$ 36,688	$ 666,486
Net loss	—	—	—	—	—	(9,320)	(9,320)
Comprehensive loss							(9,320)
Effect of adoption of SFAS No. 158, net of tax of $3,079	—	—	—	—	(3,846)	—	(3,846)
Effect of adoption of EITF 04-6, net of tax of $400	—	—	—	—	—	(638)	(638)
Effect of adoption of SFAS No. 123(R)	—	—	(4,622)	4,622	—	—	—
Issuance of restricted stock and stock awards, net of forfeitures	584,580	6	(6)	—	—	—	—
Compensation expense on share-based awards	—	—	5,668	—	—	—	5,668
Balance—December 31, 2006	152,906,488	1,529	633,937	—	(3,846)	26,730	658,350
Net loss	—	—	—	—	—	(147,034)	(147,034)
Postretirement benefit obligation adjustments, net of tax of $1,362					(2,231)	—	(2,231)
Amortization of accumulated postretirement benefit obligation, net of tax of $109	—	—	—	—	174	—	174
Comprehensive loss							(149,091)
Effect of adoption of FIN 48	—	—	—	—	—	(112)	(112)
Issuance of restricted stock and stock awards, net of forfeitures	85,621	1	(1)	—	—	—	—
Compensation expense on share-based awards	—	—	5,224	—	—	—	5,224
	152,992,109	1,530	639,160	—	(5,903)	(120,416)	514,371

Balance—December 31, 2007							
Net loss						(24,650)	(24,650)
Postretirement benefit obligation adjustments, net of tax of $727					530	—	530
Amortization of accumulated postretirement benefit obligation, net of tax of $214	—	—	—	—	216	—	216
Comprehensive loss							(23,904)
Issuance of restricted stock and stock awards, net of forfeitures	312,436	3	(3)	—	—	—	—
Stock options exercised	17,700	—	149	—	—	—	149
Compensation expense on share-based awards	—	—	4,174	—	—	—	4,174
Balance—December 31, 2008	153,322,245	$ 1,533	$ 643,480	$ —	$ (5,157)	$ (145,066)	$ 494,790

See notes to consolidated financial statements.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
Years ended December 31, 2008, 2007 and 2006
(Dollars in thousands)

	Year Ended December 31,		
	2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (24,650)	$ (147,034)	$ (9,320)
Adjustments to reconcile net loss to net cash from operating activities:			
Depreciation, depletion and amortization	96,047	86,517	72,218
Impairment loss	37,428	170,402	—
Write-off and amortization of deferred finance costs included in interest expense	2,831	8,291	3,418
Amortization of accumulated postretirement benefit obligation	430	283	—
Minority interest	—	(349)	58
Compensation expense on share-based awards	4,174	5,224	5,668
Gain on sale of assets, net	(32,518)	(38,656)	(1,125)
Provision for bad debt	994	503	—
Deferred income taxes	(23,477)	(87,078)	3,239
Changes in Assets and Liabilities:			
Accounts receivable	7,918	(13,606)	(5,885)
Inventories	(17,333)	(92)	(20,958)
Prepaid expenses and other	(3,545)	3,202	(10,201)
Other non-current assets	(2,744)	(457)	(2,553)
Accounts payable	7,116	12,588	(1,832)
Accrued expenses and other	24,677	11,648	12,268
Reclamation and mine closure costs	(5,281)	5,509	5,014
Other liabilities	5,886	5,200	5,582
Net cash from operating activities	77,953	22,095	55,591
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from the sale of assets	8,786	46,524	3,782
Net proceeds from sale-leaseback	—	—	5,413
Additions to property, plant, equipment and mine development	(131,421)	(160,431)	(165,658)
Cash paid related to acquisitions, net	(603)	(12,717)	(4,721)
Withdrawals (deposits) of restricted cash	(26)	193	415
Distribution to joint venture	—	(100)	—
Net cash from investing activities	(123,264)	(126,531)	(160,769)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings on short-term debt	6,310	26,082	10,375
Repayments on short-term debt	(1,569)	(45,368)	(20,400)
Borrowings on long-term debt	3,496	65,000	71,543
Repayments on long-term debt and capital leases	(6,295)	(68,585)	(112,418)

Debt issuance costs	—	(9,285)	(9,367)
Proceeds from stock options exercised	149	—	—
Proceeds from senior notes offering	—	—	175,000
Proceeds from convertible notes offering	—	225,000	—
Net cash from financing activities	2,091	192,844	114,733
NET CHANGE IN CASH AND CASH EQUIVALENTS	(43,220)	88,408	9,555
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	107,150	18,742	9,187
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 63,930	$ 107,150	$ 18,742
Supplemental information:			
Cash paid for interest (net of amount capitalized)	$ 36,193	$ 20,113	$ 4,898
Cash (paid) received for income taxes	$ —	$ 2,971	$ (150)
Supplemental disclosure of non-cash items:			
Purchases of property, plant, equipment and mine development through accounts payable	$ 12,942	$ 547	$ 5,145
Purchases of property, plant, equipment and mine development through financing arrangements	$ 40,708	$ 10,971	$ 26,175
Assets acquired through the assumption of liabilities	$ 17,464	$ 2,016	$ —
Assets acquired through the exchange of property	$ 22,608	$ —	$ —

See notes to consolidated financial statements

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

1. ORGANIZATION

Entity Matters—International Coal Group, Inc. ("ICG" or the "Company") is a leading producer of coal in Northern and Central Appalachia and also has operations and reserves in the Illinois Basin. The Company's customers are primarily investment grade electric utilities, as well as domestic industrial and steel customers that demand a variety of coal products. The Company's ability to produce a comprehensive range of high Btu steam and metallurgical quality coal allows it to blend coal, which enables it to market differentiated coal products to a variety of customers with different coal quality demands.

ICG, Inc. was formed on May 13, 2004 by WL Ross & Co., LLC ("WLR") and other investors to acquire and operate competitive coal mining facilities. On September 30, 2004, ICG, Inc. acquired certain properties and assets, and assumed certain liabilities, of Horizon Natural Resources Company ("Horizon") through Section 363 asset sales of the United States Bankruptcy Court.

International Coal Group, Inc. was formed in March 2005, as a wholly owned subsidiary of ICG, Inc., in order to effect a corporate reorganization. On November 18, 2005, the reorganization was completed. Prior to this reorganization, ICG, Inc. was the top-tier holding company. Upon completion of the reorganization, International Coal Group, Inc. became the new top-tier parent holding company. In the corporate reorganization, the stockholders of ICG, Inc. received one share of International Coal Group, Inc. common stock for each share of ICG, Inc. common stock. In addition, the Company completed acquisitions of Anker Coal Group, Inc. ("Anker") and CoalQuest Development, LLC ("CoalQuest"), on November 18, 2005.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND GENERAL

Principles of Consolidation—The consolidated financial statements include the accounts of ICG, whose subsidiaries are generally controlled through a majority voting interest, but may be controlled by means of a significant minority ownership, by contract, lease or otherwise. In certain cases, ICG subsidiaries (i.e., Variable Interest Entities ("VIEs")) may also be consolidated based on a risks and rewards approach as required by the Financial Accounting Standards Board ("FASB") revised Interpretation No. 46 ("FIN 46(R)"). See Note 14 to the consolidated financial statements for further discussion regarding the consolidation of VIEs. The Company accounts for its undivided interest in coalbed methane wells (see Note 7) using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in the appropriate classification in the financial statements. The consolidated financial statements are presented in accordance with accounting principles generally accepted in the United States of America. Significant intercompany transactions and balances have been eliminated.

Cash and Cash Equivalents—The Company considers all highly-liquid investments with maturities of three months or less at the time of purchase to be cash equivalents. Cash equivalents consist of a money market fund. Because of the short maturity of these investments, the carrying amounts approximate the fair value.

Accounts Receivable and Allowance for Doubtful Accounts—Accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts is the Company's best estimate of the amount of probable credit losses in the Company's existing accounts receivable. The Company establishes provisions for losses on accounts receivable when it is probable that all or part of the outstanding balance will not be collected. The Company regularly reviews collectability and establishes or adjusts the allowance as necessary.

Inventories—Components of inventories consist of coal and parts and supplies (see Note 3).

Coal inventories are stated at lower of average cost or market and represent coal contained in stockpiles, including those tons that have been mined and hauled to our loadout facilities, but not yet shipped to customers. These inventories are stated in clean coal equivalent tons and take into account any loss that may occur during the processing stage. Coal must be of a quality that can be sold on existing sales orders to be carried as coal inventory. The majority of the Company's coal inventory does not require extensive processing prior to shipment. In most cases, processing consists of crushing or sizing the coal prior to loading into the truck or rail car for shipment to the customer.

Parts and supplies inventories are valued at average cost, less an allowance for obsolescence. The Company establishes provisions for losses in parts and supplies inventory values through analysis of turnover of inventory items and adjusts the allowance as necessary.

Derivative Financial Instruments—The Company uses interest rate swaps to manage interest rate risk. The Company does not use derivative financial instruments for trading or speculative purposes. Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended ("SFAS No. 133"), establishes accounting and reporting standards for derivative instruments and hedging activities.

In May 2006, the Company entered into an Interest Rate Collar Agreement (the "Collar Agreement"), which became effective as of March 31, 2007 and will expire on March 31, 2009. The Company uses the Collar Agreement to hedge its interest rate risk on $200,000 notional amount of revolving debt. The interest rate collar is designed as a cash flow hedge to offset the impact of changes in the LIBOR interest rate above 5.92% and below 4.80%. The Company has not designated its derivatives as hedging instruments and recognizes the change in the fair value of its derivatives in its consolidated statement of operations in the period of change. The derivative liability, resulting from adjusting the Collar Agreement to its fair value of approximately $1,665, including the Company's initial net investment of $300, is included in accrued expenses and other in the Company's consolidated balance sheet at December 31, 2008. Such adjustment resulted in losses of approximately $1,993, $1,649 and $939 for years ended December 31, 2008, 2007 and 2006, respectively, and is included in interest expense.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Pursuant to EITF 90-19, Convertible Bonds with Issuer Option to Settle for Cash upon Conversion, EITF 00-19, Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company's Own Stock and EITF 01-6, The Meaning of Indexed to a Company's Own Stock , the Company's convertible notes are accounted for as convertible debt in the accompanying consolidated balance sheet and the embedded conversion option in the convertible notes has not been accounted for as a separate derivative.

Advance Royalties—The Company is required, under certain royalty lease agreements, to make minimum royalty payments whether or not mining activity is being performed on the leased property. These minimum payments may be recoupable once mining begins on the leased property. The recoupable minimum royalty payments are capitalized and amortized based on the units-of-production method at a rate defined in the lease agreement once mining activities begin. The Company has recorded net advance royalties of $22,573 and $20,188, the current portion of $5,111 and $5,528 is included in prepaid expense at December 31, 2008 and 2007, respectively. Unamortized deferred royalty costs are expensed when mining has ceased or a decision is made not to mine on such property. At December 31, 2008 and 2007, the Company has recorded allowances for such circumstances totaling $3,909 and $3,771, respectively.

Coal Supply Agreements—Purchase price allocated to the Company's below-market coal supply agreements (sales contracts) acquired in acquisitions accounted for as business combinations were capitalized and are being amortized on the basis of coal to be shipped over the term of the contracts. Purchase price allocated to the Company's above-market coal supply agreement was capitalized and is being reduced as related cash payments are received. Value was allocated to coal supply agreements based on discounted cash flows attributable to the difference between the above- or below-market contract price and the prevailing market price at the date of acquisition. The net book value of the Company's above-market coal supply agreement was $3,447 and $3,713 at December 31, 2008 and 2007, respectively. This amount is recorded in other assets in the Company's consolidated balance sheets. The net book value of the below-market coal supply agreements was $43,888 and $39,668 at December 31, 2008 and 2007, respectively. Amortization income on the below-market coal supply agreements was $9,590, $19,214 and $13,494 in 2008, 2007 and 2006, respectively. Amortization income is included in depreciation, depletion and amortization expense. Based on expected shipments related to these contracts, the Company expects to record annual amortization income on the below-market coal supply agreements in each of the next five years as reflected in the table below.

	Below-market contracts
2009	$ 10,091
2010	7,881
2011	3,186
2012	3,186
2013	3,186

Property, Plant, Equipment and Mine Development—Property, plant, equipment and mine development costs, including coal lands and mineral rights, are recorded at cost, which includes construction overhead and capitalized interest. Interest cost applicable to major asset additions is capitalized during the construction period and totaled $5,946 and $5,057 for the years ended December 31, 2008 and 2007, respectively. Expenditures for major renewals and

betterments are capitalized, while expenditures for maintenance and repairs are expensed as incurred. Coal lands and mineral rights costs are depleted using the units-of-production method, based on estimated recoverable interest. Mine development costs are amortized using the units-of-production method, based on estimated recoverable interest. Other property, plant and equipment is depreciated using the straight-line method with estimated useful lives as follows:

	Years
Buildings	10 to 45
Mining and other equipment and related facilities	1 to 20
Land improvements	15
Transportation equipment	2 to 7
Furniture and fixtures	3 to 10

Goodwill—Goodwill represents the excess of costs over fair value of net assets of businesses acquired. Pursuant to SFAS No. 142, Goodwill and Other Intangible Assets (“SFAS No. 142”), goodwill and intangible assets that are determined to have an indefinite useful life are not amortized, but instead must be tested for impairment at least annually. The goodwill impairment test consists of two steps. The first identifies potential impairment by comparing the fair value of a reporting unit with its carrying amount, including goodwill. Fair value of a reporting unit is estimated using present value techniques, such as discounted cash flows of projected future operations developed by management, or a weighting of income and market approaches. If the fair value of the reporting unit exceeds the carrying amount, goodwill is not considered impaired and the second step is not necessary. If the carrying value of the reporting unit exceeds the fair value, the second step is necessary to measure the amount of impairment loss by comparing the implied fair value of goodwill with its carrying amount. Implied fair value of goodwill is determined as the amount that the fair value of the assets of a business unit exceeds their carrying value, excluding goodwill. Impairment loss is measured as the amount of the carrying value of goodwill that exceeds its implied fair value. The Company performs its impairment test as of October 31st of each year. See Note 5.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Debt Issuance Costs—Debt issuance costs reflect fees incurred to obtain financing. Debt issuance costs related to the Company's outstanding debt are amortized over the life of the related debt. Amortization expense for the years ended December 31, 2008, 2007 and 2006 was $2,831, $8,291 and $3,418, respectively, and is included in interest expense. Amortization expense for 2008, 2007 and 2006 includes $0, $5,348 and $1,369, respectively, representing deferred financing fees written-off as a result of amending and restating the Company's prior credit agreements.

Restricted Cash—Restricted cash includes amounts required by various royalty and reclamation agreements. Restricted cash of $1,589 and $1,563 at December 31, 2008 and 2007, respectively, is included in other non-current assets.

Coal Mine Reclamation and Mine Closure Costs—The Company's asset retirement obligations arise from the Federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. The Company records these reclamation obligations according to the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations ("SFAS No. 143"). SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which the legal obligation associated with the retirement of the long-lived asset is incurred. Fair value of reclamation liabilities is determined based on the present value of the estimated future expenditures. 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 and the capitalized cost is depreciated over the useful life of the related asset. 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 recorded. On at least an annual basis, the Company reviews its entire reclamation liability and makes necessary adjustments for permit changes as granted by state authorities, additional costs resulting from accelerated mine closures and revisions to cost estimates and productivity assumptions.

Asset Impairments—The Company follows SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which requires that projected future cash flows from use and disposition of assets be compared with the carrying amounts of those assets when impairment indicators are present. When the sum of projected cash flows is less than the carrying amount, impairment losses are indicated. If the fair value of the assets is less than the carrying amount of the assets, an impairment loss is recognized. In determining such impairment losses, discounted cash flows or asset appraisals are utilized to determine the fair value of the assets being evaluated. Also, in certain situations, expected mine lives are shortened because of changes to planned operations. When that occurs and it is determined that the mine's underlying costs are not recoverable in the future, reclamation and mine closing obligations are accelerated and the mine closing accrual is increased accordingly. To the extent it is determined asset carrying values will not be recoverable during a shorter mine life, a provision for such impairment is recognized. During the year ended December 31, 2008, the Company recognized an impairment loss of $7,191 in accordance with SFAS No. 144. See Note 4.

Income Tax Provision—The provision for income taxes includes federal, state and local income taxes currently payable and deferred taxes arising from temporary differences between the financial statement and tax basis of assets and liabilities. Income taxes are recorded under the liability method. Under this method, deferred income taxes are recognized for the estimated future tax effects of differences between the tax basis of assets and liabilities and their

financial reporting amounts, as well as net operating loss carryforwards and tax credits based on enacted tax laws. Valuation allowances are established when necessary to reduce deferred tax assets to the amount expected to be realized.

The Company recognizes interest expense and penalties related to unrecognized tax benefits as interest expense and other expense, respectively, in its consolidated statement of operations.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Revenue Recognition—Coal revenues result from sales contracts (long-term coal contracts or purchase orders) with electric utilities, industrial companies or other coal-related organizations, primarily in the eastern United States. Revenue is recognized and recorded at the time of shipment or delivery to the customer, prices are fixed or determinable and the title or risk of loss has passed in accordance with the terms of the sales agreement. Under the typical terms of these agreements, risk of loss transfers to the customers at the mine or port, where coal is loaded to the rail, barge, truck or other transportation source that delivers coal to its destination.

Coal sales revenues also result from the sale of brokered coal produced by others. Revenue is recognized and recorded at the time of shipment or delivery to the customer, prices are fixed or determinable and the title or risk of loss has passed in accordance with the terms of the sale agreement. The revenues related to brokered coal sales are included in coal sales revenues on a gross basis and the corresponding cost of the coal from the supplier is recorded in cost of coal sales in accordance with Emerging Issues Task Force (“EITF”) 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent.

Freight and handling costs paid to third-party carriers and invoiced to coal customers are recorded as freight and handling costs and freight and handling revenues, respectively.

Other revenues primarily consist of contract mining income, coalbed methane sales, ash disposal services, equipment and parts sales, equipment rebuild and maintenance services, royalties and coal handling and processing income. With respect to other revenues recognized in situations unrelated to the shipment of coal, we carefully review the facts and circumstances of each transaction and apply the relevant accounting literature as appropriate and do not recognize revenue until the following criteria are met: persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the seller’s price to the buyer is fixed or determinable and collectibility is reasonably assured. Advance payments received are deferred and recognized in revenue as related income is earned.

Postretirement Benefits Other Than Pensions—As prescribed by SFAS No. 106, Employers’ Accounting for Postretirement Benefits Other Than Pensions (“SFAS No. 106”), accruals are made, based on actuarially determined estimates, for the expected costs of providing postretirement benefits other than pensions for current and future retired employees and their dependents, which are primarily healthcare and life insurance benefits, during an employee’s actual working career. Actuarial gains and losses are amortized over the estimated average remaining service period for active employees utilizing the minimum amortization method prescribed by SFAS No. 106. The Company’s liability is reduced by the amount of Medicare prescription drug reimbursement that it expects to receive under the Drug Improvement and Modernization Act of 2003. See Note 12.

As prescribed by SFAS No. 158, Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106 and 132(R), changes in the funded status of the plan are recognized through other comprehensive income.

Workers’ Compensation and Black Lung Benefits—The Company is liable under federal and state laws to pay workers’ compensation and pneumoconiosis (black lung) benefits to eligible employees. The Company utilizes a combination of participation in a state run program and insurance policies. For black lung liabilities, provisions are made for

actuarially determined estimated benefits. The Company follows SFAS No. 112, Employers' Accounting for Postemployment Benefits for purposes of accounting for its black lung liabilities.

Stock-Based Compensation—The Company accounts for its stock-based awards in accordance with SFAS No. 123(R), Share Based Payment ("SFAS No. 123(R)"). SFAS No. 123(R) establishes standards of accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. Under the fair value recognition provisions of SFAS No. 123(R), the Company measures stock-based compensation cost based upon the grant date fair value of the award, which is recognized as expense on a straight-line basis over the corresponding vesting period. The Company uses the Black-Scholes option valuation model to determine the estimated fair value of its stock options at the date of grant. Determining the fair value of share-based awards at the grant date requires several assumptions. These assumptions include the expected life of the option, the risk-free interest rate, volatility of the price of the Company's common stock and expected dividend yield on the Company's common stock. See Note 13.

Management's Use of Estimates—The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant items subject to such estimates and assumptions include, but are not limited to, the allowance for doubtful accounts; coal inventories; parts and supplies inventory reserves; coal lands and mineral rights; advance royalty reserves; asset retirement obligations; employee benefit liabilities; future cash flows associated with assets; useful lives for depreciation, depletion and amortization; income taxes; and fair value of financial instruments. Due to the subjective nature of these estimates, actual results could differ from those estimates.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Recent Accounting Pronouncements—In September 2006, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 157, Fair Value Measurements ("SFAS No. 157"). SFAS No. 157 clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. Adoption of SFAS No. 157 did not have a material impact on the Company's financial position, results of operations or cash flows; however, adoption did result in additional information being included in the footnotes accompanying the Company's consolidated financial statements. See Note 18.

In February 2008, the FASB issued FASB Staff Position ("FSP") 157-2, Effective Date of FASB Statement No. 157 ("FSP 157-2"). FSP 157-2 permits delayed adoption of SFAS 157 for certain non-financial assets and liabilities, which are not recognized at fair value on a recurring basis, until fiscal years, and interim periods within those fiscal years, beginning after November 15, 2008. Adoption of FSP 157-2 did not have a material impact on the Company's financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115 ("SFAS No. 159"). SFAS No. 159 provides entities with an option to report selected financial assets and liabilities at fair value and establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Adoption of SFAS No. 159 did not have a material impact on the Company's financial position, results of operations or cash flows.

In October 2008, the FASB issued FSP 157-3, Determining Fair Value of a Financial Asset in a Market That Is Not Active ("FSP 157-3"). FSP 157-3 clarified the application of SFAS No. 157 in an inactive market. It demonstrated how the fair value of a financial asset is determined when the market for that financial asset is inactive. FSP 157-3 was effective upon issuance, including prior periods for which financial statements had not been issued. Adoption of FSP 157-3 did not have a material impact on the Company's financial position, results of operations or cash flows.

In May 2008, the FASB issued FSP APB 14-1, Accounting for Convertible Debt Instruments That May be Settled in Cash Upon Conversion (Including Partial Cash Settlement) ("FSP APB 14-1"). FSP APB 14-1 requires the liability and equity components of convertible debt instruments that may be settled in cash upon conversion to be separately accounted for in a manner that reflects the issuer's nonconvertible debt borrowing rate. To allocate the proceeds from a convertible debt offering in this manner, a company would first need to determine the carrying amount of the liability component, which would be based on the fair value of a similar liability, excluding any embedded conversion options. The resulting debt discount would be amortized over the period during which the debt is expected to be outstanding as additional non-cash interest expense. FSP APB 14-1 is effective for financial statements for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years, and would be applied retrospectively for all periods presented. The Company has determined its non-convertible borrowing rate would have been 11.7% at issuance. The expected effect of adoption of FSP APB 14-1 is as follows:

	2008	2007

Property, plant, equipment and mine development	1,151	376
Debt issuance costs, net	(173)	(576)
Total assets	$ 978	$ (200)
Long-term debt and capital leases	$ (17,369)	$ (21,082)
Deferred tax liability	6,935	7,893
Total liabilities	(10,434)	(13,189)
Paid-in-capital	13,517	13,517
Retained deficit	(2,105)	(528)
Total stockholders' equity	11,412	12,989
Total liabilities and stockholders' equity	$ 978	$ (200)
Interest expense, net	$ (2,536)	$ (849)
Income tax benefit	959	321
Net loss	$ (1,577)	$ (528)

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), Business Combinations ("SFAS No. 141(R)"). SFAS No. 141(R) will significantly change the accounting for business combinations. Under SFAS No. 141(R), an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions. SFAS No. 141(R) will change the accounting treatment for certain specific acquisition-related items including: (i) expensing acquisition-related costs as incurred, (ii) valuing noncontrolling interests at fair value at the acquisition date and (iii) expensing restructuring costs associated with an acquired business. SFAS No. 141(R) also includes a substantial number of new disclosure requirements. SFAS No. 141(R) is to be applied to any business combination for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Upon adoption, SFAS No. 141(R) will impact the accounting for the Company's future business combinations.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements ("SFAS No. 160"). SFAS No. 160 establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary (minority interest) is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements and separate from the parent company's equity. Among other requirements, this statement requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated statement of operations, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The Company is currently evaluating the effect, if any, the adoption of SFAS No. 160 will have on its financial position, results of operations and cash flows.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133 ("SFAS No. 161"). SFAS No. 161 requires additional disclosures for derivative instruments and hedging activities that include how and why an entity uses derivatives, how these instruments and the related hedged items are accounted for under FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and related interpretations and how derivative instruments and related hedged items affect the entity's financial position, results of operations and cash flows. SFAS No. 161 is effective for fiscal years, and interim periods within those fiscal years, beginning after November 15, 2008. Adoption of SFAS No. 161 did not impact the footnotes accompanying the Company's consolidated financial statements.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles ("SFAS No. 162"). SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles. SFAS No. 162 directs the hierarchy to the entity, rather than the independent auditors, as the entity is responsible for selecting accounting principles for financial statements that are presented in conformity with generally accepted accounting principles. SFAS No. 162 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Adoption of SFAS No. 162 did not have a material impact on the Company's financial position, results of operations or cash flows.

In June 2008, the FASB issued EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities ("EITF 03-6-1"). EITF 03-6-1 clarifies that all outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders. Awards of this nature are considered participating securities and the two-class method of computing basic and diluted earnings per share must be applied. EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. Adoption of EITF 03-6-1 did not have a material impact on the Company's financial position, results of operations or cash flows.

In June 2008, the FASB ratified EITF 07-5, Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity's Own Stock ("EITF 07-5"). EITF 07-5 provides that an entity should use a two step approach to evaluate whether an equity-linked financial instrument (or embedded feature) is indexed to its own stock, including

evaluating the instrument's contingent exercise and settlement provisions. It also clarifies the impact of foreign currency denominated strike prices and market-based employee stock option valuation instruments on the evaluation. EITF 07-5 is effective for fiscal years beginning after December 15, 2008. Adoption of EITF 07-5 did not have a material impact on the Company's financial position, results of operations or cash flows.

3. INVENTORIES

As of December 31, 2008 and 2007, inventories consisted of the following:

	2008	2007
Coal	$ 28,436	$ 19,855
Parts and supplies	32,159	21,602
Reserve for obsolescence, parts and supplies	(1,807)	(778)
Total	$ 58,788	$ 40,679

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

4. PROPERTY, PLANT, EQUIPMENT AND MINE DEVELOPMENT

As of December 31, 2008 and 2007, property, plant, equipment and mine development are summarized by major classification as follows:

	2008	2007
Coal lands and mineral rights	$ 586,512	$ 594,034
Plant and equipment	571,083	442,530
Mine development	180,725	133,181
Land and land improvements	24,119	20,889
Coalbed methane well development costs	14,889	14,276
	1,377,328	1,204,910
Less accumulated depreciation, depletion and amortization	(309,182)	(230,576)
Net property, plant and equipment	$ 1,068,146	$ 974,334

Depreciation, depletion and amortization expense related to property, plant, equipment and mine development for the years ended December 31, 2008, 2007 and 2006 was $105,637, $105,726 and $85,344, respectively.

In June 2008, the Company exchanged certain coal reserves with a third-party. In addition to reserves, the Company received $3,000 in cash. As a result, the Company recognized a pre-tax gain of $24,633 based upon the fair value of the underlying assets received in the exchange, which is included in gain on sale of assets in its statement of operations for the year ended December 31, 2008. Additionally, in September 2008, the Company exchanged certain property resulting in the recognition of a $975 pre-tax gain based upon the fair value of the underlying assets given up in the exchange. The gain is included in gain on sale of assets in the Company’s statement of operations for the year ended December 31, 2008.

In December 2008, the Company made the decision to permanently close its Sago mine during the first quarter of 2009. As a result of this decision, the Company recorded a $7,191 impairment charge. The assets of the Sago mine had been included in the Company’s Northern Appalachian business segment.

In September 2007, the Company sold its Denmark reserve in Southern Illinois for $39,000 in cash. As a result, the Company recognized a gain of $36,782 which is included in gain on sale of assets in its statement of operations for the year ended December 31, 2007. Under terms of the transaction, the purchaser is also obligated to pay the Company an overriding royalty totaling $4,000 on certain future production that will be recognized as the reserves are mined.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

5. GOODWILL

The Company recorded goodwill related to its acquisition of certain assets and assumption of certain liabilities of Horizon and Anker/CoalQuest. The Company assigned the goodwill to certain of the acquired reporting units based on their estimated fair values. In accordance with SFAS No. 142, the Company tests goodwill for impairment on an annual basis, at a minimum, and more frequently if a triggering event occurs. The 2008 goodwill testing identified impairment of goodwill at the Company's ADDCAR Systems, LLC ("ADDCAR") subsidiary resulting in a $30,237 impairment loss. The loss reflects the negative impact of several contributing factors which resulted in a reduction in the forecasted cash flows to estimate fair value. These factors include but are not limited to less than anticipated demand for and increased costs of contract mining services, an increased reliance on lower-margin mining equipment sales and the need for capital investment to replace aging equipment. Furthermore, the business, regulatory and marketplace environment in which the Company currently operates differs significantly from the historical environment that drove the business case used to value and record the acquisition of this business unit. Accordingly, the Company has been unable to attain the forecasted projections that were used to initially value the business unit at the date of acquisition.

The goodwill testing performed in 2007 identified impairment of goodwill at the following business units: $32,914 at Hazard, $58,511 at Eastern, $42,941 at East Kentucky and $36,036 at Knott County.

In 2006, goodwill and certain assets acquired and liabilities assumed were adjusted to fair value as a result of the finalization of the purchase price allocation associated with the Anker/CoalQuest acquisitions. Goodwill was primarily allocated to property, plant, equipment and mine development. The adjustments to the purchase price allocation of Horizon represents allocation of additional purchase price due to excess actual expenses related to the acquisition over management's original estimates and reallocation of purchase price to assets and liabilities for which fair values were not available at the time of the acquisition. The adjustments to the purchase price allocation of Horizon recorded during 2006 were due to a refund of legal fees held in escrow. Bonding royalties represent payments made on the gross sales receipts for coal mined and sold by the former Horizon companies that ICG acquired (see Note 16). At December 31, 2006, the entire goodwill balance related to the Horizon acquisition.

The changes in the carrying amount of goodwill were as follows:

Balance as of December 31, 2005	$ 344,394
Adjustments to purchase price allocation of Horizon	(812)
Bonding royalty	3,975
Adjustments to purchase price allocation of Anker/CoalQuest	(150,800)
Balance as of December 31, 2006	196,757
Bonding royalty	3,882
Impairment loss	(170,402)
Balance as of December 31, 2007	30,237
Impairment loss	(30,237)
Balance as of December 31, 2008	$ —

6. ACCRUED EXPENSES AND OTHER

As of December 31, 2008 and 2007, accrued expenses and other consisted of the following:

	2008	2007
Compensation and related expenses	$ 38,076	$ 25,147
Interest	17,776	17,330
Royalties	5,826	4,282
Sales and production related taxes	5,574	5,098
Deferred revenue	5,506	—
Personal property, land and mineral taxes	3,719	3,582
Transportation	3,453	2,655
Other	7,774	4,629
Total	$ 87,704	$ 62,723

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

7. INVESTMENT IN JOINT OPERATING AGREEMENT

In July 2005, CoalQuest entered into an agreement with CDX Gas, LLC ("CDX") for the purpose of exploration and development of coalbed methane under a joint operating agreement, whereby CoalQuest has the right to obtain up to a 50% undivided working interest in each well drilled on property owned by the Company. The Company accounts for this joint operation using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in the appropriate classification in the Company's financial statements. As of December 31, 2008 and 2007, the Company recorded assets of $2,356 and $5,891 net of accumulated depletion of $12,533 and $8,385, respectively, related to the operating agreement. This amount is included in net property, plant, equipment and mine development in the consolidated balance sheet. For the years ended December 31, 2008, 2007 and 2006, the Company recorded $8,597, $7,741 and $1,949 and $2,935, $983 and $313, respectively, of coalbed methane revenue and royalty income, respectively, related to the operating agreement which is included in other revenues in the consolidated statement of operations. During 2008, CDX declared bankruptcy. As a result, the Company recorded a reserve against outstanding accounts receivable due from CDX totaling $1,282.

8. ACQUISITION

In May 2008, the Company entered into an agreement to purchase the membership interests of Powdul Acquisition LLC. The purchase resulted in the Company acquiring the idle Powell Mountain underground mining operation and related assets. The cost of the acquired entity totaled $18,067 which included cash paid of $450, other related acquisition costs of $153 and total liabilities of $17,464. Total liabilities include current liabilities of $132, asset retirement obligations of $3,522 and a below-market contract valued at $13,810. As a result of the purchase price allocation, the Company recorded current assets of $1,335, mineral interests of $10,998, development costs of $1,922 and property, plant and equipment of $3,812. The acquisition would not have had a material impact on the Company's results of operations had it taken place on January 1, 2008.

9. DEBT

Long-Term Debt and Capital Leases

As of December 31, 2008 and 2007, long-term debt and capital leases consisted of the following:

	2008	2007
9.00% Convertible Senior Notes, due 2012	$ 225,000	$ 225,000
10.25% Senior Notes, due 2014	175,000	175,000
Equipment notes	43,378	12,330
Capital leases and other	6,861	—
Total	450,239	412,330
Less current portion	15,319	4,234
Long-term debt	$ 434,920	$ 408,096

Convertible senior notes—In 2007, the Company completed a private offering of $225,000 aggregate principal amount of 9.00% Convertible Senior Notes (the “Convertible Notes”) due 2012. The Convertible Notes are the Company’s senior unsecured obligations and are guaranteed on a senior unsecured basis by the Company’s material future and current domestic subsidiaries. The Convertible Notes and the related guarantees rank equal in right of payment to all of the Company’s and the guarantors’ respective existing and future unsecured senior indebtedness. Interest is payable semi-annually in arrears on February 1 and August 1 of each year.

Table of Contents

The Convertible Notes became convertible at the option of holders beginning July 1, 2008. The conversion period expired on September 30, 2008 pursuant to the terms of the governing indenture with no holders exercising their conversion rights. The Convertible Notes may become convertible again in the future under certain conditions. Accordingly, the Company will reassess the convertibility on a quarterly basis.

The principal amount of the Convertible Notes is payable in cash and amounts above the principal amount, if any, will be convertible into shares of the Company's common stock or, at the Company's option, cash. The Convertible Notes are convertible at an initial conversion price, subject to adjustment, of $6.10 per share (approximating 163.8136 shares per one thousand dollar principal amount of the Convertible Notes). The volume weighted-average price of the Company's stock subsequent to the expiration date of the conversion period was below $6.10 per share. Accordingly, there were no potentially convertible shares at December 31, 2008. The Convertible Notes are convertible upon the occurrence of certain events, including (i) prior to February 12, 2012 during any calendar quarter after September 30, 2007, if the closing sale price per share of the Company's 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; (ii) prior to February 12, 2012 during the five consecutive business days immediately after any five consecutive trading day period in which the average trading price for the notes on each day during such five trading-day period was equal to or less than 97% of the closing sale price of the Company's common stock on such day multiplied by the then current conversion rate; (iii) upon the occurrence of specified corporate transactions; and (iv) at any time from, and including February 1, 2012 until the close of business on the second business day immediately preceding August 1, 2012. In addition, upon events defined as a "fundamental change" under the Convertible Notes indenture, the Company may be required to repurchase the Convertible Notes at a repurchase price in cash equal to 100% of the principal amount of the notes to be repurchased, plus any accrued and unpaid interest to, but excluding, the fundamental change repurchase date. As such, in the event of a fundamental change or the aforementioned average pricing thresholds are met, the Company would be required to classify the entire amount outstanding of the Convertible Notes as a current liability in the following quarter. In the event that a significant number of the holders of the Convertible Notes were to convert their notes prior to maturity, the Company may not have enough available funds at any particular time to make the required repayments. Under these circumstances, the Company would look to WLR, its banking group and other potential lenders to obtain short-term funding until such time that it could secure necessary financing on a long-term basis. The availability of any such financing would depend upon the circumstances at the time, including the terms of any such financing, and other factors. In addition, if conversion occurs in connection with certain changes in control, the Company may be required to deliver additional shares of the Company's common stock (a "make whole" premium) by increasing the conversion rate with respect to such notes. For a discussion of the effects of the Convertible Notes on earnings per share, see Note 15.

Senior notes—In 2006, the Company sold $175,000 aggregate principal amount of the Company's 10.25% Senior Notes (the "Notes") due July 15, 2014. Interest on the Notes is payable semi-annually in arrears on July 15 and January 15 of each year. The Notes are senior unsecured obligations and are guaranteed on a senior unsecured basis by all of the Company's current and future domestic subsidiaries that are material or that guarantee the Company's amended and restated credit facility. The Notes and the guarantees rank equally with all of the Company's and the guarantors' existing and future senior unsecured indebtedness, but are effectively subordinated to all of the Company's and the

guarantors existing and future senior secured indebtedness to the extent of the value of the assets securing that indebtedness and to all liabilities of the Company's subsidiaries that are not guarantors. The Company has the option to redeem all or a portion of the Notes at 100% of the aggregate principal amount at maturity at any time on or after July 15, 2010. At any time prior to July 15, 2010, the Company may also redeem all or a portion of the Notes at a redemption price equal to 100% of the aggregate principal amount of the Notes plus an applicable premium as of, and accrued and unpaid interest and additional interest, if any, to, but not including the date of redemption. At any time before July 15, 2009, the Company may also redeem up to 35% of the aggregate principal amount of the Notes at a redemption price of 110.25% of the principal amount, plus accrued and unpaid interest, if any, to the date of redemption, with the proceeds of certain equity offerings. Upon a change of control, the Company may be required to offer to purchase the Notes at a purchase price equal to 101% of the principal amount, plus accrued and unpaid interest.

The indenture governing the Notes contains covenants that limit the Company's ability to, among other things, incur additional indebtedness, issue preferred stock, pay dividends, repurchase, repay or redeem the Company's capital stock, make certain investments, sell assets and incur liens. As of December 31, 2008, the Company was in compliance with its covenants under the indenture.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Credit facility—In 2006, the Company entered into a second amended and restated credit agreement (the "Amended Credit Facility") consisting of a revolving credit facility which matures on June 23, 2011. In July 2007, concurrent with the issuance of the Convertible Notes, the Company again amended the Amended Credit Facility to reduce the commitments thereunder to $100,000 of which a maximum of $80,000 may be used for letters of credit. The amendment, among other things, modified the maximum permitted leverage ratio, the minimum interest coverage ratio and the maximum amount of capital expenditures permitted. Further, the amendment revised certain interest rate thresholds and unused commitment fee levels under the Amended Credit Facility. In February 2009, the Company executed a further amendment to the Amended Credit Facility that affected certain 2009 debt covenants. The amendment modified the maximum permitted leverage and minimum interest coverage ratios. The amendment also decreased the maximum capital spending and added a minimum liquidity requirement. Debt covenants for years subsequent to 2009 were not affected by the amendment. As of December 31, 2008, the Company had no borrowings outstanding and letters of credit totaling $73,551 outstanding, leaving $26,449 available for future borrowing capacity. Interest on the borrowings under the Amended Credit Facility is payable, at the Company's option, at either the base rate plus an applicable margin based on the Company's leverage ratio of 1.25% to 2.00% as of December 31, 2008 or LIBOR plus an applicable margin based on the Company's leverage ratio of 2.25% to 3.00% as of December 31, 2008. As of December 31, 2008, the Company was in compliance with its financial covenants under the Amended Credit Facility.

Equipment notes and other—The equipment notes, having various maturity dates extending to January 2014, are collateralized by mining equipment. As of December 31, 2008, the Company had amounts outstanding for 36-month through 60-month terms with a weighted-average interest rate of 6.42%. At December 31, 2008, additional funds are available under the Company's revolving equipment credit facility for terms ranging from 36 to 60 months with a current interest rate of 8.75%. Additionally, the Company finances certain of its annual insurance premiums at a current interest rate of 5.42%.

Future maturities of long-term debt and capital leases are as follows as of December 31, 2008:

Year ending December 31:	
2009	$ 15,319
2010	11,771
2011	9,839
2012	232,936
2013	5,306
Thereafter	175,068
Total	$ 450,239

Short-Term Debt

The Company finances the majority of its annual insurance premiums, a portion of which is included in short-term debt. The weighted-average interest rate applicable to the notes was 4.65%. As of December 31, 2008 and 2007, the Company had $4,741 and $0, respectively, outstanding related to insurance financing.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

10. ASSET RETIREMENT OBLIGATION

The Company's 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.

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

At December 31, 2008 and 2007, the asset retirement obligation accrual for reclamation and mine closure costs totaled $79,246 and $85,920, respectively. The assets that give rise to the obligation are primarily related to mine development, preparation plants and loadouts.

The following schedule represents activity in the accrual for reclamation and mine closure costs for the years ended December 31:

	2008	2007
Balance at beginning of year	$ 85,920	$ 92,670
Revisions of estimated cash flows	(5,896)	(12,620)
Liabilities incurred (net of disposals) or assumed in acquisitions	1,438	7,295
Expenditures	(9,594)	(8,237)
Accretion	7,378	6,812
Balance at end of year	$ 79,246	$ 85,920

At December 31, 2008 and 2007, the accrued reclamation and mine closure costs are included in the accompanying consolidated balance sheets as follows:

	2008	2007
Current portion of reclamation and mine closure costs	$ 11,139	$ 7,333
Non-current portion of Reclamation and mine closure costs (non-current)	68,107	78,587
Total	$ 79,246	$ 85,920

11. INCOME TAXES

The income tax benefit for the years ended December 31, 2008, 2007 and 2006 are comprised of the following:

	2008	2007	2006
Current:			
Federal	$ 375	$ 1,046	$ (11,487)
State	391	409	(767)
	766	1,455	(12,254)
Deferred:			
Federal	(21,019)	(75,406)	2,637
State	(2,458)	(11,672)	602
	(23,477)	(87,078)	3,239
Income tax benefit	$ (22,711)	$ (85,623)	$ (9,015)

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

The following table presents the difference between the income tax benefit in the accompanying statements of operations and the amounts obtained by applying the statutory U.S. federal income tax rate of 35% to income and losses before income taxes for the years ended December 31, 2008, 2007 and 2006:

	2008	2007	2006
Federal income tax benefit computed at statutory rate	$ (16,576)	$ (81,430)	$ (6,397)
State income tax expense (net of federal tax benefits) computed at statutory rate	(1,343)	(7,321)	(108)
Percentage depletion in excess of tax basis at statutory rate	(6,477)	(1,784)	(3,084)
Penalties	1,869	—	—
Goodwill impairment	(490)	4,046	—
Other	306	866	574
Income tax benefit	$ (22,711)	$ (85,623)	$ (9,015)

Significant components of the Company's deferred tax assets and liabilities as of December 31, are summarized as follows:

	2008	2007
Deferred tax assets:		
Accrued employee benefits	$ 24,523	$ 23,352
Accrued reclamation and closure	30,274	31,271
Below-market contracts	15,691	16,777
NOL carryover	68,909	48,637
Goodwill	53,960	40,501
Other	19,705	11,100
	213,062	171,638
Deferred tax liabilities:		
Property, coal lands and mine development costs	(232,937)	(212,474)
Other	(4,944)	(6,519)
	(237,881)	(218,993)
Net deferred tax liability	$ (24,819)	$ (47,355)
Classified in balance sheet:		
Deferred income taxes—current	$ 17,649	$ 5,000
Deferred income taxes—non-current	(42,468)	(52,355)
Total	$ (24,819)	$ (47,355)

The Company has a total net operating loss ("NOL") carryover of $186,441, of which $2,707 expires in 2024, $17,154 expires in 2025, $5,331 expires in 2026, $99,748 expires in 2027 and $61,501 expires in 2028. The Company is subject to a limitation of approximately $6,900 per year on $19,861 of the NOLs attributable to certain acquired

entities. However, due to the cumulative nature of the limitation, the Company has full utilization of NOLs starting in 2008. The Company also has an alternative minimum tax ("AMT") loss in the amount of $35,392, of which $4,451 expires in 2024, $16,796 expires in 2025, and $14,145 expires in 2028. The AMT NOL attributable to certain acquired entities of $21,247 is subject to the same annual limitation specified above for the regular NOL. The NOLs reflect $582 of excess tax deductions, which reduce the NOL carryforward portion of the deferred tax asset. The Company will recognize the excess tax deduction at such time that the deduction will reduce taxes payable. Adjustments have been made to certain regular and AMT NOL carryovers as a result of current Internal Revenue Service audits of 2006 and 2007.

Internal Revenue Code ("IRC") Section 382 imposes significant limitations on the annual utilization of NOL carryforwards if a "change in ownership" is deemed to occur. Generally, an ownership change is deemed to occur if the Company experiences a cumulative change in ownership of greater than 50% within a three-year testing period. The Company completed an IRC Section 382 study and determined that an ownership change had occurred. Although the IRC Sec 382 ownership change result in an annual limitation of the Company's NOL carryforwards, all NOLs are expected to be fully utilized within the remaining NOL carryforward period.

The Company recorded a valuation allowance of $2,396 against certain state NOL carryforwards that, more likely than not, are expected to expire without being utilized.

The Company files income tax returns in the U.S. and various states. Generally, the Company is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2005. The Company is currently under examination by the Internal Revenue Service and the state of West Virginia for certain tax years pertaining to income taxes.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

12. EMPLOYEE BENEFITS

Employee benefits at December 31, 2008 and 2007 are summarized as follows:

	2008	2007
Postretirement benefits	$ 27,974	$ 25,024
Black lung benefits	27,455	24,788
Workers' compensation benefits	7,847	6,781
Coal Act benefits	1,277	1,464
Total	64,553	58,057
Less current portion	3,359	2,925
Employee benefits—non-current	$ 61,194	$ 55,132

Valuation Date—All actuarially determined benefits were determined as of December 31, 2008 and 2007.

Postretirement Benefits—Employees of the Company who complete ten years of service, and certain employees who have completed eight years of service with the former Horizon companies and complete two years with ICG, will be eligible to receive postretirement benefits, which consists of healthcare benefits. Upon reaching the retirement age of 65, in order to receive a maximum medical life-time benefit of one hundred thousand dollars per family, eligible retired employees must pay two hundred and fifty dollars per month per family. The Company accrues postretirement benefit expense based on actuarially determined amounts. The amount of postretirement benefit cost accrued is impacted by various assumptions (discount rate, healthcare cost increases, etc.) that the Company uses in determining its postretirement obligations. The Company assumed discount rates of 6.25% and 6.50% for the years ended December 31, 2008 and 2007, respectively. Postretirement benefit expense for the Company totaled $4,664, $3,394 and $2,021 for the years ended December 31, 2008, 2007 and 2006, respectively.

Postretirement benefit information for the years ended December 31, 2008 and 2007 is as follows:

	2008	2007
Changes in Benefit Obligations:		
Accumulated benefit obligations at beginning of period	$ 25,024	$ 18,331
Service cost	2,607	2,057
Interest cost	1,627	1,054
Actuarial (gain)/loss	(1,257)	3,593
Benefits paid	(27)	(11)
Accumulated benefit obligation at end of period	27,974	25,024
Fair value of plan assets at end of period	—	—
Net liability recognized	$ 27,974	$ 25,024

The changes in the actuarial loss that are included in accumulated other comprehensive income were as follows:

Balance as of December 31, 2007	$ 10,235
Actuarial gain	(1,257)
Amortization of actuarial gain	(430)
Balance as of December 31, 2008	8,548

The Company expects to recognize $288 of the net actuarial gain as a component of the net periodic benefit cost during 2009. Components of net periodic benefit cost for the years ended December 31, 2008, 2007 and 2006 are as follows:

	2008	2007	2006
Net periodic benefit cost:			
Service cost	$ 2,607	$ 2,057	$ 1,297
Interest cost	1,627	1,054	668
Amortization of actuarial gain/loss	430	283	56
Benefit cost	$ 4,664	$ 3,394	$ 2,021

For measurement purposes, an 8.33% annual rate of increase in the per capita cost of covered healthcare benefits was assumed, gradually decreasing to 5.00% in 2015 and remaining level thereafter.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

The expense and liability estimates can fluctuate by significant amounts based upon the assumptions used. As of December 31, 2008, a one-percentage-point increase in assumed healthcare cost trend rates would increase total service and interest cost components and the postretirement benefit obligation by $410 and $1,793, respectively. Conversely, a one-percentage-point decrease would reduce total service and interest cost components and the postretirement benefit obligation by $378 and $1,713, respectively.

Estimated future benefit payments for the years indicated ending after December 31, 2008 are as follows:

2009	$ 523
2010	925
2011	1,580
2012	2,134
2013	2,934
2014 – 2018	25,652
Total	$ 33,748

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the “Act") provides for a prescription drug benefit under Medicare (“Medicare Part D”), as well as a federal subsidy to sponsors of retiree healthcare benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. The Company accounts for the subsidy as prescribed by FSP FAS 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (“FSP 106-2”). As of December 31, 2008, the Company determined the effects of the Act resulted in a $426 reduction of its postretirement benefit obligation. The Act is expected to result in a $113 reduction of the Company’s postretirement benefit cost for the year ended December 31, 2009. The effect on the Company’s postretirement benefit cost components includes reductions of $65, $27 and $21 to the service cost, interest cost and amortization of accumulated postretirement benefit obligation, respectively.

Workers’ Compensation and Black Lung—The operations of the Company are subject to the federal and state workers’ compensation laws. These laws provide for the payment of benefits to disabled workers and their dependents, including lifetime benefits for black lung. The Company’s subsidiary operations are insured by a combination of participation in a state run program and insurance policies. The Company’s workers’ compensation liability is discounted at 5.50%.

The Company’s actuarially determined liability for self-insured black lung benefits is based on a 5.75% discount rate and various other assumptions, including incidence of claims, benefits escalation, terminations and life expectancy. The annual black lung expense consists of actuarially determined amounts for self-insured obligations. The estimated amount of discounted obligations for self-insured black lung claims, plus an estimate for incurred but not reported claims, was $22,824 and $17,758 as of December 31, 2008 and 2007, respectively. The unrecognized projected black lung benefit obligations (difference between recorded accrual and projected obligations) at December 31, 2008 and 2007 was a gain of approximately $4,631 and $7,030, respectively, and is being provided for over the future service period of current employees. The projected black lung obligations may vary in a given year based on the timing of

claims filed and changes in assumptions. The Company recorded expenses related to black lung of $1,097, $2,709 and $4,245 for the years ended December 31, 2008, 2007 and 2006, respectively.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

UMWA Combined Benefit Fund (Coal Act)—The Coal Industry Retiree Health Benefit Act of 1992 (the "Coal Act") provides for the funding of medical and death benefits for certain retired members of the UMWA. It provides for the assignment of beneficiaries to their former employers and any unassigned beneficiaries to employers based on a formula. Based upon actuarially determined amounts for the latest list of beneficiaries assigned to Anker, the Company estimates the amount of its obligation under the Coal Act to be approximately $1,277 and $1,464 as of December 31, 2008 and 2007, discounted at 6.25% and 6.00%, respectively. The Company recorded interest expense related to the Coal Act of $80, $302 and $345 for the years ended December 31, 2008, 2007 and 2006, respectively.

401(k) Plans—The Company sponsors a savings and retirement plan for substantially all employees. The Company matches voluntary contributions of participants, except for those previously employed by Anker, up to a maximum contribution of 3% of a participant's salary. The Company also contributes an additional 3% non-elective contribution for every employee eligible to participate in the program. The expense under this plan for the Company was $6,971, $4,293 and $5,182 for the years ended December 31, 2008, 2007 and 2006, respectively.

For those employees previously employed by Anker, and who meet eligibility requirements, the Company also has a 401(k) savings plan. The plan provides for a 100% match of the first 3% of employee contributions and 50% of the next 2% of employee contributions. The Company also contributes an additional 5% non-elective contribution for every employee eligible to participate in the program. The expense under this plan for the Company was $1,956, $1,776 and $1,736 for the years ended December 31, 2008, 2007 and 2006, respectively.

13. EMPLOYEE STOCK AWARDS

The Company's 2005 Equity and Performance Incentive Plan (the "Plan") permits the granting of stock options, restricted shares, stock appreciation rights, restricted share units, performance shares or performance units to its employees for up to 8,000,000 shares of common stock. Option awards are generally granted with an exercise price equal to the market price of the Company's stock at the date of grant and have 10-year contractual terms. The option and restricted stock awards generally vest in equal annual installments of 25% over a four-year period. The Company recognizes expense related to the awards on a straight-line basis over the vesting period. The Company issues new shares upon the exercise of option awards.

The Black-Scholes option pricing model was used to calculate the estimated fair value of the options granted. The estimated grant date fair value of the options granted in 2008, 2007 and 2006 was calculated using the following assumptions:

	2008	2007	2006
Expected term (in years)	5	5	5
Expected volatility	43.0% - 48.2%	43.0% - 48.1%	48.1%
Weighted-average volatility	43.5%	43.2%	48.1%
Risk-free rate	1.7% - 3.7%	4.0% - 5.1%	4.6% - 5.2%

Expected dividends	—	—	—

The Company estimated a forfeiture rate of 4.50%, 3.25% and 1.00% for 2008, 2007 and 2006, respectively.

Due to the Company's limited operating history, the expected lives and volatility are estimated based on other companies in the coal industry. The risk-free interest rates are based on the rates of zero coupon U.S. Treasury bonds with similar maturities on the date of grant. The forfeiture rate was determined based on estimates of future turnover of the Company's employees eligible under the plan.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Stock-based employee compensation expense of $2,596, $3,134 and $3,501, net of tax of $1,578, $2,090 and $2,167, related to the issuance of all stock awards outstanding was included in earnings for the years ended December 31, 2008, 2007 and 2006, respectively.

A summary of the Company's outstanding options as of December 31, 2008, and changes during the year ended December 31, 2008, is as follows:

Options	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (years)	Aggregate Intrinsic Value
Outstanding at January 1, 2008	2,012,342	$ 8.76		
Granted	1,055,160	6.35		
Exercised	(17,700)	8.39		
Forfeited and expired	(218,610)	8.44		
Outstanding at December 31, 2008	2,831,192	7.88	7.9	$ (15,811)
Vested or expected to vest at December 31, 2008	2,725,556	7.93	7.9	$ (15,338)
Exercisable at December 31, 2008	1,329,907	9.28	7.0	$ (9,280)

The weighted-average grant-date fair value of options granted during the years ended December 31, 2008, 2007 and 2006 was $2.64, $2.65 and $3.93, respectively. The total intrinsic value of options exercised during the year ended December 31, 2008 was $47. There were no options exercised in 2007 or 2006.

A summary of the status of the Company's nonvested restricted stock awards as of December 31, 2008 and changes during the year ended December 31, 2008 is as follows:

Nonvested Shares	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2008	574,190	$ 9.15
Granted	349,194	6.74
Vested	(323,020)	10.40
Forfeited	(44,020)	8.00
Nonvested at December 31, 2008	556,344	7.00

The weighted-average grant-date fair value of restricted stock granted during the years ended December 31, 2008, 2007 and 2006 was $6.74, $5.87 and $8.50, respectively. The total fair value of restricted stock vested during the years ended December 31, 2008, 2007 and 2006 was $3,361, $3,221 and $2,933, respectively.

As of December 31, 2008, there was $6,237 of unrecognized compensation cost related to non-vested stock-based awards that is expected to be recognized over a weighted-average period of 2.6 years.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

14. VARIABLE INTEREST ENTITIES

The Company acquired a 50% interest in Sycamore Group, LLC ("Sycamore") in conjunction with its acquisition of Anker. Sycamore was established as a joint venture with an unrelated third-party to mine coal from the Sycamore No. 1 mine. The reserve from Sycamore No. 1 was depleted and the mine closed during the first quarter of 2007. The Company considers itself to be the primary beneficiary of Sycamore, based on an evaluation of its involvement with Sycamore and the provisions of FIN 46(R), and has consolidated the accounts of Sycamore as of December 31, 2008 and 2007, as well as the results of operations for the year ended December 31, 2008, 2007 and 2006. The creditors of Sycamore have no recourse to the general credit of ICG. Amounts related to Sycamore that are included in the consolidated financial statements of ICG as of and for the years ending December 31, 2008, 2007 and 2006, are as follows:

	2008	2007	2006
Assets	$ 213	$ 257	$ 3,342
Liabilities	138	187	1,097
Revenue	—	1,808	10,343
Net income (loss)	—	(403)	130

15. EARNINGS PER SHARE

Reconciliations of the weighted-average shares used to compute basic and diluted earnings per share for the years ended December 31, 2008, 2007 and 2006 are as follows:

	2008	2007	2006
Net loss	$ (24,650)	$ (147,034)	$ (9,320)
Average common shares outstanding—Basic	152,632,586	152,304,461	152,028,165
Incremental shares arising from stock options	—	—	—
Incremental shares arising from restricted shares	—	—	—
Incremental shares arising from convertible notes	—	—	—
Average common shares outstanding—Diluted	152,632,586	152,304,461	152,028,165
Earnings Per Share:			
Basic and Diluted	$ (0.16)	$ (0.97)	$ (0.06)

Options to purchase 2,831,192 shares of common stock and 556,344 shares of restricted common stock outstanding at December 31, 2008 have been excluded from the computation of diluted net loss per share for the year ended December 31, 2008 because their effect would have been anti-dilutive. Options to purchase 2,012,342 shares of common stock and 574,190 shares of restricted common stock outstanding at December 31, 2007 have been excluded

from the computation of diluted net loss per share for the year ended December 31, 2007 because their effect would have been anti-dilutive. Options to purchase 1,814,302 shares of common stock and 787,540 shares of restricted common stock outstanding at December 31, 2006 have been excluded from the computation of diluted net loss per share for the year ended December 31, 2006 because their effect would have been anti-dilutive.

In July 2007, the Company completed the offering of its Convertible Notes. The principal amount of the Convertible Notes is payable in cash and amounts above the principal amount, if any, will be convertible into shares of the Company's common stock or, at the Company's option, cash. The volume weighted-average price of the Company's stock during the applicable measurement period was below $6.10 per share. Accordingly, there were no potentially dilutive shares at December 31, 2008.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

16. COMMITMENTS AND CONTINGENCIES

Guarantees and Financial Instruments with Off-balance Sheet Risk—In the normal course of business, the Company is a party to certain guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. No liabilities related to these arrangements are reflected in the Company's consolidated balance sheets. Management does not expect any material losses to result from these guarantees or off-balance sheet financial instruments.

Coal Sales Contracts—As of December 31, 2008, the Company had commitments under 49 sales contracts to deliver annually scheduled base quantities of coal to 34 customers. The contracts expire from 2009 through 2020 with the Company contracted to supply a minimum of approximately 63.5 million tons of coal over the remaining lives of the contracts (maximum of approximately 16.9 million tons in 2009).

Diesel Fuel Purchase Contracts—As of December 31, 2008, the Company had commitments to purchase $73,753 of diesel fuel during 2009. The Company did not have material diesel fuel purchase contacts in place for the purchase of diesel fuel during the years ended December 31, 2008, 2007 or 2006.

Coal Purchase Contracts—As of December 31, 2008, the Company had commitments to purchase coal to meet its sales commitments. Certain of the contracts have sales price adjustment provisions, subject to certain limitations and adjustments, based on a variety of factors and indices. The following is a summary of the Company's future contractual purchase obligations by year as of December 31, 2008:

Year ending December 31:	
2009	$ 22,926
2010	14,377
Total	$ 37,303

The Company incurred purchased coal expense of approximately $23,363, $13,892 and $41,874 for the years ended December 31, 2008, 2007 and 2006 related to these coal purchase contracts.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Leases—The Company leases various mining, transportation and other equipment under operating and capital leases. Lease expense for the years ended December 31, 2008, 2007 and 2006 was $4,970, $6,254 and $15,194, respectively. Property under capital lease included in property, plant, equipment and mine development in the consolidated balance sheet at December 31, 2008 was approximately $3,816, less accumulated depreciation of approximately $0. There were no capital leases at December 31, 2007. At December 31, 2008, the Company imputed interest on its capital lease using a rate of 10% in order to reduce the net minimum lease payments to present value. Depreciation expense related to assets under capital leases is included in depreciation, depletion and amortization in the Company's consolidated statement of operations.

The Company also leases coal lands and mineral rights under agreements that call for royalties to be paid as the coal is mined. Total royalty expense for the years ended December 31, 2008, 2007 and 2006 was approximately $52,232, $37,680 and $38,458, respectively. Certain agreements require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Certain agreements may be cancelable at the Company's discretion.

Non-cancelable future minimum royalty and lease payments as of December 31, 2008 are as follows:

	Royalties	Operating Leases	Capital Leases
Year ended December 31,			
2009	$ 10,111	$ 87	$ 1,726
2010	9,925	63	1,726
2011	9,715	19	863
2012	8,408	—	—
2013	8,228	—	—
Thereafter	37,004	—	—
Total minimum lease payments	$ 83,391	$ 169	$ 4,315
Less—amount representing interest			499
Present value of minimum lease payments			3,816
Less—current portion			1,430
Total long-term portion of capital leases			$ 2,386

Bonding Royalty and Additional Payment—Lexington Coal Company, LLC ("LCC") was organized in part by the founding ICG stockholders in conjunction with the acquisition of the former Horizon companies. LCC was organized to assume certain reclamation liabilities and assets of Horizon not otherwise being acquired by ICG or others. There was initially a limited commonality of ownership of LCC and ICG. In order to provide support to LCC, ICG provided a $10,000 letter of credit to support reclamation obligations (Bonding Royalty) and in addition agreed to pay a 0.75% payment on the gross sales receipts for coal mined and sold by the former Horizon companies that ICG acquired from Horizon until the completion by LCC of all reclamation liabilities that LCC assumed from Horizon ("Additional Payments"). The Company made payments totaling $4,457, $3,883 and $3,975 for the years ended December 31, 2008, 2007 and 2006, respectively.

Under the Bonding Royalty, ICG was required to pay an additional 0.75% on gross sales referred to above to a fund controlled by one of its sureties until all letters of credit issued by such surety for both ICG and LCC were cash collateralized. During 2005, the surety released ICG of its obligation to maintain additional cash collateral and refunded all of the cash previously paid to collateralize the letters of credit. In March 2006, the $10,000 letter of credit to support reclamation obligations (Bonding Royalty) was also released. Under the provisions of FIN 46(R), ICG has determined it does not hold a significant variable interest in LCC and it is not the primary beneficiary of LCC.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Legal Matters—On August 23, 2006, a survivor of the Sago mine accident, Randal McCloy, filed a complaint in the Kanawha Circuit Court in Kanawha County, West Virginia. The claims brought by Randal McCloy and his family against the Company and certain of its subsidiaries, and against W.L. Ross & Co., and Wilbur L. Ross, Jr., individually, were dismissed on February 14, 2008, after the parties reached a confidential settlement. Sixteen other complaints have been filed in Kanawha Circuit Court by the representatives of many of the miners who died in the Sago mine accident, and several of these plaintiffs have filed amended complaints to expand the group of defendants in the cases. The complaints allege various causes of action against the Company and its subsidiary, Wolf Run Mining Company, one of the Company's shareholders, W.L. Ross & Co., and Wilbur L. Ross Jr., individually, related to the accident and seek compensatory and punitive damages. In addition, the plaintiffs also allege causes of action against other third parties, including claims against the manufacturer of Omega block seals used to seal the area where the explosion occurred and against the manufacturer of self-contained self-rescuer ("SCSR") devices worn by the miners at the Sago mine. Some of these third parties have been dismissed from the actions upon settlement. The amended complaints add other of the Company's subsidiaries to the cases, including ICG, Inc., ICG, LLC and Hunter Ridge Coal Company, unnamed parent, subsidiary and affiliate companies of the Company, W.L. Ross & Co., and Wilbur L. Ross Jr., and other third parties, including a provider of electrical services and a supplier of components used in the SCSR devices. The Company believes that it is appropriately insured for these and other potential claims, and it has fully paid its deductible applicable to its insurance policies. In addition to the dismissal of the McCloy claim, the Company has settled and dismissed five other actions. These settlements required the release of the Company, the Company's subsidiaries, W. L. Ross & Co., and Wilbur L. Ross, Jr. Some of the plaintiffs involved in one of the dismissed actions have sought permission from the Supreme Court of Appeals of West Virginia to appeal the settlement, alleging that the settlement negotiated by the decedent's estate should not have been approved by the trial court. The trial court overruled those plaintiffs' objections to the settlement, and, although the West Virginia Supreme Court of Appeals refused to stay the effectiveness of the settlement, the plaintiffs' petition for appeal to the West Virginia Supreme Court of Appeals was recently presented to the court. The court has not yet ruled whether it will accept the petition for appeal or decline to hear the appeal. The Company will vigorously defend itself against the remaining complaints and any appeal of any prior settlements.

Allegheny Energy Supply ("Allegheny"), the sole customer of coal produced at the Company's subsidiary Wolf Run Mining Company's ("Wolf Run") Sycamore No. 2 mine, filed a lawsuit against Wolf Run, Hunter Ridge Holdings, Inc. ("Hunter Ridge"), and the Company in state court in Allegheny County, Pennsylvania on December 28, 2006, and amended its complaint on April 23, 2007. Allegheny claims that the Company breached a coal supply contract when it declared force majeure under the contract upon idling the Sycamore No. 2 in the third quarter of 2006. The Sycamore No. 2 mine was idled after encountering adverse geologic conditions and abandoned gas wells that were previously unidentified and unmapped. The amended complaint also alleges that the production stoppages constitute a breach of the guarantee agreement by Hunter Ridge and breach of certain representations made upon entering into the contract in early 2005, a claim that Allegheny has since voluntarily dropped. Allegheny claims that it will incur costs in excess of $100,000 to purchase replacement coal over the life of the contract. The Company, Wolf Run and Hunter Ridge answered the amended complaint on August 13, 2007, disputing all of the remaining claims. On November 3, 2008, the Company, Wolf Run and Hunter Ridge filed an amended answer and counterclaim against the plaintiffs seeking to void the coal supply agreement due to, among other things, fraudulent inducement and conspiracy. The counterclaim alleges further that Allegheny breached a confidentiality agreement with Hunter Ridge, which prohibited the

solicitation of its employees. After the coal supply agreement was executed, Allegheny hired the then-president of Anker Coal Group, Inc. (now Hunter Ridge) who engaged in negotiations on behalf of Wolf Run and Hunter Ridge. In addition to seeking a declaratory judgment that the coal supply agreement and guaranty be deemed void and unenforceable and rescission of the contracts, the counterclaim also seeks compensatory and punitive damages.

On December 6, 2007, the Kentucky Waterways Alliance, Inc., and The Sierra Club sued the U.S. Army Corps of Engineers (the "ACOE") in the United States District Court for the Western District of Kentucky, Louisville Division (the "Court"), asserting that a permit to construct five valley fills was issued unlawfully to the Company's Hazard subsidiary for its Thunder Ridge Surface mine. The suit alleges that the ACOE failed to comply with the requirements of both Section 404 of the Clean Water Act and the National Environmental Policy Act. Hazard has intervened in the suit to protect the Company's interests. The ACOE suspended the Section 404 permit on December 26, 2007 in order to evaluate the issues raised by the plaintiffs. That evaluation is now in progress. If the ACOE reinstates the permit and the Court subsequently finds that the permit is unlawful, production could be materially affected at the Thunder Ridge Surface mine and the process of obtaining ACOE permits for coal mining activities in Kentucky could become more difficult.

On January 7, 2008, Saratoga Advantage Trust filed a class action lawsuit in the U.S. District Court for the Southern District of West Virginia against the Company and certain of its officers and directors. The complaint asserts claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder, based on alleged false and misleading statements in the registration statements filed in connection with the Company's November 2005 reorganization and December 2005 public offering of common stock. In addition, the complaint challenges other of the Company's public statements regarding the Company's operating condition and safety record. The Company intends to vigorously defend the action.

On July 3, 2007, Taylor Environmental Advocacy Membership, Inc. ("T.E.A.M.") filed a petition to appeal the issuance of ICG Tygart Valley, LLC's ("Tygart Valley") Surface Mine Permit U-2004-06 against the West Virginia Department of Environmental Protection (the "WVDEP") in an action before the West Virginia Surface Mine Board (the "Board"). On December 10, 2007, the Board remanded the permit to the WVDEP for revision to certain provisions related to pre-mining water monitoring and cumulative hydrologic impacts. The WVDEP issued a modification on April 1, 2008 addressing those issues. T.E.A.M. filed an appeal of the WVDEP's approval of the permit modification on April 30, 2008. On October 7, 2008, the Board issued an order remanding the permit to the WVDEP requiring Tygart Valley to address a technical issue related to projected post-mining water quality. Tygart Valley has prepared and submitted a permit modification to alleviate the board's concerns. All site development will be suspended until the WVDEP has approved the permit modification. If the WVDEP issues the permit as modified, there will be additional opportunity for appeal by T.E.A.M.

From time to time, the Company is involved in legal proceedings arising in the ordinary course of business. These proceedings include assessments of penalties for citations and orders asserted by the Mine Safety and Health Administration, and other regulatory agencies none of which are expected by management to individually or in the aggregate have a material adverse effect on the Company. In the opinion of management, the Company has recorded adequate reserves for liabilities arising in the ordinary course and it is management's belief there is no individual case or group of related cases pending that is likely to have a material adverse effect on the financial condition, results of operations or cash flows of the Company.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Environmental Matters—Based upon current knowledge, the Company believes it is in material compliance with environmental laws and regulations as currently promulgated. However, the exact nature of environmental control problems, if any, which the Company may encounter in the future cannot be predicted, primarily because of the increasing number, complexity and changing character of environmental requirements that may be enacted by federal and state authorities.

Performance Bonds—The Company has outstanding surety bonds with third parties of approximately $115,667 as of December 31, 2008 to secure reclamation and other performance commitments. In addition, at December 31, 2008 the Company has $73,551 of letters of credit outstanding under the revolving credit facility, a portion of which $61,126 provides support to the third parties for their issuance of surety bonds. In addition, the Company has posted cash collateral of $1,589 and $1,563 to secure reclamation and other performance commitments as of December 31, 2008 and 2007, respectively. This cash collateral is included in other non-current assets on the consolidated balance sheets.

Contract Mining Agreements—ICG's subsidiary, ADDCAR, performs contract mining services for various third parties and utilizes contract miners on some of its operations. Terms of the agreements generally allow either party to terminate the agreements on a short-term basis. The guaranteed monthly contract tonnage is mutually agreed upon and failure to meet the guaranteed contract tonnage may result in termination of the contract. Completion dates for work under these contracts vary in dates ranging from 2009 to 2010.

17. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

The Company markets its coal principally to electric utilities in the United States, the majority of which have investment grade credit ratings. As of December 31, 2008 and 2007, trade accounts receivable from electric utilities totaled approximately $49,059 and $57,029, respectively. The Company evaluates each customer's creditworthiness prior to entering into transactions and constantly monitors the credit extended, but does not require its customers to provide collateral. Credit losses are provided for in the consolidated financial statements and historically have been minimal.

The Company had coal sales to the following major customers that equaled or exceeded 10% of revenues:

	December 31, 2008 Total Receivable Balance	Year Ended December 31, 2008 Total Revenues	December 31, 2007 Total Receivable Balance	Year Ended December 31, 2007 Total Revenues	December 31, 2006 Total Receivable Balance	Year Ended December 31, 2006 Total Revenues
Customer A	$ —	$ —	$ 2,886	$ 97,389	$ 4,893	$ 135,025
Customer B	—	—	—	—	6,397	117,249
Customer C	—	—	—	—	6,041	94,935

Deposits held with banks may exceed the amount of insurance provided on such deposits. Generally, these deposits may be redeemed upon demand and are maintained with financial institutions of reputable credit and, therefore, bear minimal risk.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

18. FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of the Company's financial instruments are determined based on relevant market information. These estimates involve uncertainty and cannot be determined with precision. The following methods and assumptions were used to estimate the fair value of each class of financial instrument.

Effective January 1, 2008, the Company adopted SFAS No. 157, which clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. SFAS No. 157 applies whenever other statements require or permit assets or liabilities to be measured at fair value. SFAS No. 157 requirements for certain non-financial assets and liabilities have been deferred until the first quarter of 2009 in accordance with FASB Staff Position 157-2, Effective Date of FASB Statement No. 157. SFAS No. 157 establishes the following fair value hierarchy that prioritizes the inputs used to measure fair value:

- Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets.

- Level 2 – Inputs other than Level 1 that are based on observable market data, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets, quoted prices for identical assets or liabilities in inactive markets, inputs that are observable that are not prices and inputs that are derived from or corroborated by observable markets.

- Level 3 – Developed from unobservable data, reflecting an entity's own assumptions.

The Company entered into an Interest Rate Collar Agreement (the "Collar") that expires on March 31, 2009. The interest rate collar was designed as a cash flow hedge to offset the impact of changes in the LIBOR interest rate above 5.92% and below 4.80%. At December 31, 2008, a liability for the fair value of the Collar was included in accrued expenses and other on the Company's consolidated balance sheet. The value of the interest rate collar is based on a forward LIBOR curve, which is observable at commonly quoted intervals for the full term of the agreement. The Company recognizes the change in the fair value of this agreement in the period of change. For the years ended December 31, 2008, 2007 and 2006, the Company recorded losses of $1,993, $1,649 and $939 respectively, related to the change in fair value. The losses are included in interest expense in the Company's consolidated statement of operations.

The following table presents the fair value hierarchy for financial liabilities measured at fair value on a recurring basis:

	Fair Value Measurements Using:		
Description	Quoted Prices	Significant	Significant

	December 31, 2008	in Active Markets for Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Interest Rate Collar Agreement	$ 1,665	$ —	$ 1,665	$ —

Cash and Cash Equivalents, Accounts Receivable, Accounts Payable, Short-Term Debt and Other Current Liabilities—The carrying amounts approximate the fair value due to the short maturity of these instruments.

Long-term Debt—At December 31, 2008 and 2007, the Company had $225,000 aggregate principal amount of its 9.0% Convertible Notes outstanding. The fair value of the Convertible Notes was approximately $114,683 and $266,445 as of December 31, 2008 and 2007, respectively. At December 31, 2008 and 2007, the Company had $175,000 aggregate principal amount of its 10.25% Senior Notes outstanding. The fair value of the Senior Notes was approximately $131,250 and $167,125 as of December 31, 2008 and 2007, respectively.

The carrying value of the Company’s capital lease obligations and other debt approximate fair value at December 31, 2008 and 2007.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

19. RELATED PARTY TRANSACTIONS AND BALANCES

Under an Advisory Services Agreement dated as of October 1, 2004 between the Company and WLR, WLR has agreed to provide advisory services to the Company (consisting of consulting and advisory services in connection with strategic and financial planning, investment management and administration and other matters relating to the business and operation of the Company of a type customarily provided by sponsors of U.S. private equity firms to companies in which they have substantial investments, including any consulting or advisory services which the Board of Directors reasonably requests). WLR is paid a quarterly fee of $500 and reimbursed for any reasonable out-of-pocket expenses (including expenses of third-party advisors retained by WLR). The agreement is for a period of seven years; however, it may be terminated upon the occurrence of certain events.

The Company has paid legal fees relating to the representation of WLR and the Company's Chairman, Mr. Wilbur L. Ross, Jr., by counsel in connection with various litigation matters pending against the Company, WLR and Mr. Wilbur L. Ross, Jr. related to the Sago mine accident. The Company did not record any expense in 2008 relating to these matters. During the year ended December 31, 2007 the Company recorded expenses totaling approximately $739 relating to these matters.

20. SEGMENT INFORMATION

The Company extracts, processes and markets steam and metallurgical coal from deep and surface mines for sale to electric utilities and industrial customers, primarily in the eastern United States. The Company operates only in the United States with mines in the Central Appalachian, Northern Appalachian and Illinois Basin regions. The Company has three reportable business segments: Central Appalachian, Northern Appalachian and Illinois Basin. The Company's Central Appalachian operations are located in southern West Virginia, eastern Kentucky and western Virginia and include eight mining complexes. The Company's Northern Appalachian operations are located in northern West Virginia and Maryland and include four mining complexes. The Company's Illinois Basin operations include one mining complex. The Company also has an Ancillary category, which includes the Company's brokered coal functions, corporate overhead, contract highwall mining services and land activities.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Reportable segment results for continuing operations for the year ended December 31, 2008 and segment assets as of December 31, 2008 were as follows:

	Central Appalachian	Northern Appalachian	Illinois Basin	Ancillary	Consolidated
Revenue	$ 702,958	$ 230,660	$ 79,682	$ 83,436	$ 1,096,736
Adjusted EBITDA	107,186	23,687	14,784	(18,436)	127,221
Depreciation, depletion and amortization	64,132	17,884	7,342	6,689	96,047
Impairment losses	—	7,191	—	30,237	37,428
Capital expenditures	111,980	41,624	7,146	11,069	171,819
Total assets	751,018	184,666	40,848	373,137	1,349,669

Revenue in the Ancillary category consists primarily of $46,720 relating to the Company's brokered coal sales and $19,862 relating to contract highwall mining activities. Capital expenditures include non-cash amounts of $53,650 for the year ended December 31, 2008. Capital expenditures do not include $14,290 paid during the year ended December 31, 2008 related to capital expenditures accrued in prior periods.

Reportable segment results for continuing operations for the year ended December 31, 2007 and segment assets as of December 31, 2007 were as follows:

	Central Appalachian	Northern Appalachian	Illinois Basin	Ancillary	Consolidated
Revenue	$ 530,255	$ 133,284	$ 68,440	$ 117,176	$ 849,155
Adjusted EBITDA	47,442	(22,215)	15,463	18,363	59,053
Depreciation, depletion and amortization	60,015	9,467	6,527	10,508	86,517
Impairment losses	170,402	—	—	—	170,402
Capital expenditures	129,021	37,896	2,639	11,695	181,251
Total assets	653,288	161,306	37,861	451,108	1,303,563
Goodwill	—	—	—	30,237	30,237

Revenue in the Ancillary category consists primarily of $76,802 relating to the Company's brokered coal sales and $18,994 relating to contract highwall mining activities. Capital expenditures include non-cash amounts of $11,518.

Reportable segment results for continuing operations for the year ending December 31, 2006 and segment assets as of December 31, 2006 were as follows:

	Central Appalachian	Northern Appalachian	Illinois Basin	Ancillary	Consolidated
Revenue	$ 541,844	$ 122,041	$ 56,606	$ 171,103	$ 891,594

Adjusted EBITDA	108,598	(36,586)	4,476	(4,456)	72,032
Depreciation, depletion and amortization	48,050	10,822	6,287	7,059	72,218
Capital expenditures	95,033	73,173	7,950	20,822	196,978
Total assets	752,200	147,285	41,103	376,303	1,316,891
Goodwill	167,105	—	—	29,652	196,757

Revenue in the Ancillary category consists primarily of $141,919 relating to the Company's brokered coal sales and $25,249 relating to contract highwall mining activities. Capital expenditures include non-cash amounts of $31,320.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

Adjusted EBITDA represents net income before deducting interest expense, income taxes, depreciation, depletion, amortization, impairment charges and minority interest. Adjusted EBITDA is presented because it is an important supplemental measure of the Company's performance used by the Company's chief operating decision maker.

Reconciliation of net loss to Adjusted EBITDA is as follows:

	Year Ended December 31,		
	2008	2007	2006
Net loss	$ (24,650)	$ (147,034)	$ (9,320)
Depreciation, depletion and amortization	96,047	86,517	72,218
Interest expense, net	41,107	35,140	18,091
Income tax benefit	(22,711)	(85,623)	(9,015)
Impairment loss	37,428	170,402	—
Minority interest	—	(349)	58
Adjusted EBITDA	$ 127,221	$ 59,053	$ 72,032

21. SUPPLEMENTARY GUARANTOR INFORMATION

International Coal Group, Inc. (the "Parent Company") issued $175,000 of Senior Notes due 2014 (the "Notes") in June 2006 and $225,000 of Convertible Senior Notes due 2012 (the "Convertible Notes") in July 2007. The Parent Company has no independent assets or operations other than those related to the issuance, administration and repayment of the Notes and the Convertible Notes. All subsidiaries of the Parent Company (the "Guarantors"), except for a minor non-guarantor joint venture, have fully and unconditionally guaranteed the Notes and the Convertible Notes on a joint and several basis. The Guarantors are 100% owned, directly or indirectly, by the Parent Company. Accordingly, condensed consolidating financial information for the Parent Company and the Guarantors are not presented.

The Notes and the Convertible Notes are senior obligations of the Parent Company and are guaranteed on a senior basis by the Guarantors and rank senior in right of payment to the Parent Company's and Guarantors' future subordinated indebtedness. Amounts borrowed under the Amended Credit Facility are secured by substantially all of the assets of the Parent Company and the Guarantors on a priority basis, so the Notes and Convertible Notes are effectively subordinated to amounts borrowed under the Amended Credit Facility. Other than for corporate related purposes or interest payments required by the Notes or Convertible Notes, the Amended Credit Facility restricts the Guarantors' abilities to make loans or pay dividends to the Parent Company in excess of $25,000 per year (or at all upon an event of default) and restricts the ability of the Parent Company to pay dividends. Therefore, all but $25,000 of the subsidiaries' assets are restricted assets.

The Parent Company and Guarantors are subject to certain covenants under the indenture for the Notes. Under these covenants, the Parent Company and Guarantors are subject to limitations on the incurrence of additional indebtedness, payment of dividends and the incurrence of liens, however, the indenture contains no restrictions on the ability of the Guarantors to pay dividends or make payments to the Parent Company.

The obligations of the Guarantors are limited to the maximum amount permitted under bankruptcy law, the Uniform Fraudulent Conveyance Act, the Uniform Fraudulent Transfer Act or any similar Federal or state law respecting fraudulent conveyance or fraudulent transfer.

Table of Contents

INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
For the years ended December 31, 2008, 2007 and 2006
(Dollars in thousands, except per share amounts)

22. QUARTERLY DATA

The following is a summary of selected quarterly financial information (unaudited):

	2008			
	Three months ended March 31	Three months ended June 30	Three months ended September 30	Three months ended December 31
Revenue	$ 251,925	$ 277,885	$ 309,199	$ 257,727
Income (loss) from operations	(7,369)	30,461	20,726	(50,072)
Net income (loss)	(11,546)	14,138	9,708	(36,950)
Basic earnings per common share	$ (0.08)	$ 0.09	$ 0.06	$ (0.24)
Diluted earnings per common share	$ (0.08)	$ 0.08	$ 0.06	$ (0.24)

	2007			
	Three months ended March 31	Three months ended June 30	Three months ended September 30	Three months ended December 31
Revenue	$ 228,314	$ 208,050	$ 207,829	$ 204,962
Income (loss) from operations	(8,815)	(10,850)	10,230	(188,750)
Net loss	(8,068)	(10,234)	(1,283)	(127,449)
Basic earnings per common share	$ (0.05)	$ (0.07)	$ (0.01)	$ (0.84)
Diluted earnings per common share	$ (0.05)	$ (0.07)	$ (0.01)	$ (0.84)

Included in the three months ended December 31, 2008 and 2007 are impairment losses of $37,428 and $170,402, respectively. For 2008, $30,237 of the loss related to impairment of goodwill at the Company's ADDCAR subsidiary and $7,191 related to impairment of long-lived assets. For 2007, the impairment loss related to impairment of goodwill at various of the Company's business units. See Notes 4 and 5 to the Company's consolidated financial statements for further discussion of the impairment losses.

Table of Contents

Schedule I—Condensed Financial Information of the Registrant

International Coal Group, Inc.

Parent Company Balance Sheets
(Dollars in thousands, except per share amounts)

	December 31, 2008	December 31, 2007
ASSETS		
DEBT ISSUANCE COSTS, net	9,024	11,206
DEFERRED INCOME TAXES	25,741	10,482
INVESTMENT IN SUBSIDIARIES	876,734	909,471
Total assets	$ 911,499	$ 931,159
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accrued expenses and other	$ 16,709	$ 16,788
Total current liabilities	16,709	16,788
LONG-TERM DEBT AND CAPITAL LEASES	400,000	400,000
Total liabilities	416,709	416,788
COMMITMENTS AND CONTINGENCIES	—	—
STOCKHOLDERS' EQUITY:		
Preferred stock – par value $0.01, 200,000,000 shares authorized, none issued	—	—
Common stock – par value $0.01, 2,000,000,000 shares authorized, 153,322,245 and 152,992,109 shares, respectively, issued and outstanding	1,533	1,530
Additional paid-in capital	643,480	639,160
Accumulated other comprehensive loss	(5,157)	(5,903)
Retained deficit	(145,066)	(120,416)
Total stockholders' equity	494,790	514,371
Total liabilities and stockholders' equity	$ 911,499	$ 931,159

Table of Contents

International Coal Group, Inc.

Parent Company Statements of Operations
(Dollars in thousands, except per share amounts)

	Year Ended December 31,		
	2008	2007	2006
INCOME FROM OPERATIONS	$ —	$ —	$ —
INTEREST AND OTHER INCOME (EXPENSE):			
Interest expense, net	(40,369)	(27,730)	(9,684)
Loss before income taxes	(40,369)	(27,730)	(9,684)
INCOME TAX (EXPENSE) BENEFIT	15,259	10,482	3,702
EQUITY IN NET INCOME (LOSS) OF SUBSIDIARIES	460	(129,786)	(3,338)
Net loss	$ (24,650)	$ (147,034)	$ (9,320)
Earnings per share:			
Basic and diluted	$ (0.16)	$ (0.97)	$ (0.06)
Weighted-average common shares outstanding:			
Basic and diluted	152,632,586	152,304,461	152,028,165

Table of Contents

International Coal Group, Inc.

Parent Company Statements of Cash Flows
(Dollars in thousands)

	Year Ended December 31,		
	2008	2007	2006
NET CASH FROM OPERATING ACTIVITIES	$ (38,266)	$ (19,036)	$ —
CASH FLOWS FROM INVESTING ACTIVITIES:			
Investment in subsidiaries	38,266	(198,121)	(170,047)
Net cash from investing activities	38,266	(198,121)	(170,047)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from senior notes offering	—	—	175,000
Proceeds from convertible notes offering	—	225,000	
Debt issuance costs	—	(7,843)	(4,953)
Net cash from financing activities	—	217,157	170,047
NET CHANGE IN CASH AND CASH EQUIVALENTS	—	—	—
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	—	—	—
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ —	$ —	$ —

Table of Contents

LONG-TERM DEBT

As of December 31, 2008 and 2007, long-term debt consisted of the following (in thousands):

	2008	2007
9.00% Convertible Senior Notes, due 2012	$ 225,000	$ 225,000
10.25% Senior Notes, due 2014	175,000	175,000
Total	400,000	400,000
Less current portion	—	—
Long-term debt	$ 400,000	$ 400,000

Convertible senior notes—In 2007, the Company completed a private offering of $225,000 aggregate principal amount of 9.00% Convertible Senior Notes (the “Convertible Notes”) due 2012. The Convertible Notes are the Company’s senior unsecured obligations and are guaranteed on a senior unsecured basis by the Company’s material future and current domestic subsidiaries. The Convertible Notes and the related guarantees rank equal in right of payment to all of the Company’s and the guarantors’ respective existing and future unsecured senior indebtedness. Interest is payable semi-annually in arrears on February 1 and August 1 of each year.

Senior notes—In 2006, the Company sold $175,000 aggregate principal amount of the Company’s 10.25% Senior Notes (the “Notes”) due July 15, 2014. Interest on the Notes is payable semi-annually in arrears on July 15 and January 15 of each year. The Notes are senior unsecured obligations and are guaranteed on a senior unsecured basis by all of the Company’s current and future domestic subsidiaries that are material or that guarantee the Company’s amended and restated credit facility.

The indenture governing the Notes contains covenants that limit the Company’s ability to, among other things, incur additional indebtedness, issue preferred stock, pay dividends, repurchase, repay or redeem the Company’s capital stock, make certain investments, sell assets and incur liens. As of December 31, 2008, the Company was in compliance with its covenants under the indenture.

See Note 9 to the consolidated financial statements included elsewhere in the Annual Report of Form 10-K for further discussion of the Convertible Notes and Notes.

Future maturities of long-term debt are as follows as of December 31, 2008 (in thousands):

Year ending December 31:	
2009	$ —
2010	—
2011	—
2012	225,000
2013	—
Thereafter	175,000
Total	$ 400,000

Table of Contents

Schedule II—Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Charged to Revenue, Costs or Expenses	Other Additions (Deductions)	Balance at End of Period
		(in thousands)		
Year ended December 31, 2008				
Allowance for doubtful accounts	$ 539	$ 994	$ (17)	$ 1,516
Reserve for inventory obsolescence	778	1,029	—	1,807
Reserve for loss—advance royalties	3,771	630	(492)	3,909
Year ended December 31, 2007				
Allowance for doubtful accounts	$ 36	$ 503	$ —	$ 539
Reserve for inventory obsolescence	576	(82)	284	778
Reserve for loss—advance royalties	638	3,414	(281)	3,771
Year ended December 31, 2006				
Allowance for doubtful accounts	$ —	$ 36	$ —	$ 36
Reserve for inventory obsolescence	311	265	—	576
Reserve for loss—advance royalties	—	(412)	1,050	638

Table of Contents

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.

Date: February 27, 2008

INTERNATIONAL COAL GROUP, INC.

By: /s/ Bennett K. Hatfield
Bennett K. Hatfield
President and Chief Executive 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 the capabilities and on the dates indicated.

Signature	Title	Date
/s/ Bennett K. Hatfield Bennett K. Hatfield	President, Chief Executive Officer and Director (Principal Executive Officer)	February 27, 2008
/s/ Bradley W. Harris Bradley W. Harris	Senior Vice President and Chief Financial Officer (Principal Accounting and Principal Financial Officer)	February 27, 2008
* Wilbur L. Ross, Jr.	Non-Executive Chairman and Director	February 27, 2008
* Maurice E. Carino, Jr.	Director	February 27, 2008
* Cynthia B. Bezik	Director	February 27, 2008

* William J. Catacosinos	Director	February 27, 2008
* Stanley N. Gaines	Director	February 27, 2008
* Samuel A. Mitchell	Director	February 27, 2008
* Wendy L. Teramoto	Director	February 27, 2008

* The undersigned, by signing his name hereto, does sign and execute this Annual Report on Form 10-K pursuant to the Powers of Attorney executed by the above-named officers and Directors of the Company and filed with the Securities and Exchange Commission on behalf of such officers and Directors.

INTERNATIONAL COAL GROUP, INC.

By: /s/ Bennett K. Hatfield
Bennett K. Hatfield,
Attorney-in-Fact

Table of Contents

EXHIBIT INDEX

Exhibit No.	Description	Note
2.1	Business Combination Agreement among International Coal Group, Inc. (n/k/a ICG, Inc.), ICG Holdco, Inc. (n/k/a International Coal Group, Inc.), ICG Merger Sub, Inc., Anker Merger Sub, Inc. and Anker Coal Group, Inc., dated as of March 31, 2005	(B)
2.2	First Amendment to the Business Combination Agreement among International Coal Group, Inc. (f/k/a ICG Holdco, Inc.), ICG, Inc. (f/k/a International Coal Group, Inc.), ICG Merger Sub, Inc., Anker Merger Sub, Inc. and Anker Coal Group, Inc., dated as of May 10, 2005	(B)
2.3	Second Amendment to the Business Combination Agreement among International Coal Group, Inc. (f/k/a ICG Holdco, Inc.), ICG, Inc. (f/k/a International Coal Group, Inc.), ICG Merger Sub, Inc., Anker Merger Sub, Inc. and Anker Coal Group, Inc., effective as of June 29, 2005	(C)
2.4	Business Combination Agreement among International Coal Group, Inc. (n/k/a ICG, Inc.), ICG Holdco, Inc. (n/k/a International Coal Group, Inc.), CoalQuest Merger Sub LLC, CoalQuest Development LLC and the members of CoalQuest Development LLC, dated as of March 31, 2005	(B)
2.5	First Amendment to the Business Combination Agreement among International Coal Group, Inc. (f/k/a ICG Holdco, Inc.), ICG, Inc. (f/k/a International Coal Group, Inc.), CoalQuest Merger Sub LLC, CoalQuest Development LLC and the members of CoalQuest Development LLC, dated as of May 10, 2005	(B)
2.6	Second Amendment to the Business Combination Agreement among International Coal Group, Inc. (f/k/a ICG Holdco, Inc.), ICG, Inc. (f/k/a International Coal Group, Inc.), CoalQuest Merger Sub LLC, CoalQuest Development LLC and the members of CoalQuest Development LLC, effective as of June 29, 2005	(C)
3.1	Form of Second Amended and Restated Certificate of Incorporation of International Coal Group, Inc.	(E)
3.2	Form of Second Amended and Restated By-laws of International Coal Group, Inc.	(F)
4.1		(D)

	Form of certificate of International Coal Group, Inc. common stock	
4.2	Registration Rights Agreement by and between International Coal Group, Inc., WLR Recovery Fund II, L.P., Contrarian Capital Management LLC, Värde Partners, Inc., Greenlight Capital, Inc., and Stark Trading, Shepherd International Coal Holdings Inc.	(B)
4.3	Form of Registration Rights Agreement between International Coal Group, Inc. and certain former Anker Stockholders and CoalQuest members	(C)
4.4	Indenture, dated June 23, 2006, by and among ICG, the guarantors party thereto and The Bank of New York Trust Company, N.A., as trustee relating to International Coal Group, Inc.'s 10.25% senior notes	(H)
4.5	Form of 10.25% senior note (included in Exhibit 4.1)	(H)
4.6	Form of guarantee relating to International Coal Group, Inc.'s 10.25% senior notes (included in Exhibit 4.1)	(H)
4.7	Indenture, dated as of July 31, 2007, among International Coal Group, Inc., and the guarantors party thereto and The Bank of New York Trust Company, N.A. as Trustee, relating to International Coal Group, Inc.'s 9.00% Convertible Notes.	(J)
4.8	Form of 9.00% Senior Convertible Note (included in Exhibit 4.7)	(J)
4.9	Form of Guarantee relating to International Coal Group, Inc.'s 9.00% Convertible Notes	(J)
4.10	Registration Rights Agreement, dated as of July 31, 2007, among International Coal Group, Inc., and the guarantors party thereto and UBS Securities LLC as purchaser.	(J)
10.1	Second Amended and Restated Credit Agreement, dated June 23, 2006, by and among ICG, LLC, as borrower, the guarantors party thereto, the lenders party thereto, J.P. Morgan Securities Inc. and UBS Securities LLC, as joint lead arrangers and joint bookrunners, JPMorgan Chase Bank, N.A. and CIT Capital Securities LLC, as co-syndication agents, Bank of America, N.A. and Wachovia Bank, N.A. as co-documentation agents, JPMorgan Chase Bank, N.A. and Bank of America, N.A. as issuing banks, UBS Loan Finance LLC, as swingline lender, and UBS AG, Stamford Branch, as an issuing bank, administrative agent and collateral agent	(H)

Table of Contents

Exhibit No.	Description	Note
10.2	Security Agreement dated as of September 30, 2004 among ICG, LLC and the guarantors party thereto and UBS AG, Stamford Branch, as Collateral Agent	(A)
10.3	Advisory Services Agreement effective as of October 1, 2004 between International Coal Group, LLC and W.L. Ross & Co. LLC	(A)
10.4	Employment Agreement dated March 14, 2005 by and between Bennett K. Hatfield and International Coal Group, Inc.	(A)
10.5	Employment Agreement dated April 25, 2005 by and between Roger L. Nicholson and International Coal Group, Inc.	(B)
10.6	International Coal Group, Inc. 2005 Equity and Performance Incentive Plan	(D)
10.7	International Coal Group, Inc. 2005 Equity and Performance Incentive Plan: Incentive Stock Option Agreement	(D)
10.8	International Coal Group, Inc. 2005 Equity and Performance Incentive Plan: Non-Qualified Stock Option Agreement	(D)
10.9	International Coal Group, Inc. 2005 Equity and Performance Incentive Plan: Restricted Share Agreement	(D)
10.10	Form of Indemnification Agreement	(D)
10.11	Fee Lease between Kentucky Union Company, lessor, and ICG Hazard, LLC (assigned from Leslie Resources, Inc.), lessee, of Flint Ridge Surface Mine, amended by: (a) Assignment of Real Property Agreements, dated September 30, 2004, assigning to ICG Hazard, LLC	(C)
10.14	Coal Lease between Knight-Ink Heirs, lessor, and ICG Eastern, LLC (assigned from Cherry River Coal and Coke Company), lessee, of Birch River Mine, amended by: (a) Partial Assignment of Lease, dated September 20, 1984, assigning to Twin River Coal Co. (b) General Conveyance, Assignment and Transfer, dated December 8, 1988, assigning to Island Creek Coal Co.	(C)

(c) Assignment, dated December 12, 1990, assigning to Laurel Run Mining Co.

(d) Consent Letter, dated as of October 25, 1995

(e) Partial Assignment, dated October 30, 1995, assigning to East Kentucky Energy Corp.

(f) Assignment, dated October 30, 1995, assigning to East Kentucky Energy Corp.

(g) Assignment of Real Property Agreements, dated September 30, 2004, assigning to ICG Eastern, LLC

Table of Contents

Exhibit No.	Description	Note
10.15	Coal Lease between NGHD Lands, et. al., lessor, and ICG Eastern, LLC (assigned from Coastal Coal-West Virginia, LLC), lessee, of Birch River Mine, amended by: (a) Lease and Sublease Agreement, dated March 14, 2001 (b) Memorandum of Lease and Sublease Agreement, dated June 1, 2001 (c) Assignment of Real Property Agreements, dated September 30, 2004, assigning to ICG Eastern, LLC	(C)
10.17	Fee Lease between M-B, LLC, lessor, and ICG Eastern, LLC (assigned from ANR Coal Development Company), lessee, of Birch River Mine, amended by: (a) Lease and Sublease Agreement, dated March 14, 2001 (b) Memorandum of Lease and Sublease Agreement, dated June 1, 2001 (c) Assignment of Real Property Agreements, dated September 30, 2004, assigning to ICG Eastern, LLC	(C)
10.18	Fee Lease between ACIN (successor-in-interest to CSTL, LLC), lessor, and ICG Hazard, LLC (assigned from Leslie Resources, Inc.), lessee, of County Line and Rowdy Gap Mines, amended by: (a) Assignment of Real Property Agreements, dated September 30, 2004, assigning to ICG Hazard, LLC	(C)
10.19	Fee Lease between Kentucky River Properties, LLC, lessor, and ICG Hazard, LLC (assigned from Shamrock Coal Company), lessee, of Rowdy Gap and Thunder Ridge Mines, amended by: (a) Agreement of Assignment, dated July 8, 1992, assigning to Ray Coal Company, Inc. (b) Assignment and Assumption Agreement, dated June 30, 1994, assigning to Ikerd-Bandy, Co. (c) Assignment of Real Property Agreements, dated September 30, 2004, assigning to ICG Hazard, LLC	(C)
10.20		(C)

	Lease between Allegany Coal and Land Company, lessor, and Patriot Mining Company, Inc., lessee, of Allegany County, Maryland Mine, including: (a) Amendment 1, dated and effective June 7, 1999 (b) Amendment 2, dated and effective August 31, 1999 (c) Amendment 3, dated and effective June 1, 2000 (d) Amendment 4, dated and effective June 1, 2001 (e) Default Letter, dated and effective May 6, 2002 (f) Letter Agreement, dated and effective May 8, 2002	
10.21	Lease between The Crab Orchard Coal and Land Company, lessor, and Wolf Run Mining Company (f/k/a Anker West Virginia Mining Company), ICG Beckley, LLC (successor-in-interest to Winding Gulf Coals, Inc.), lessee, of Beckley Mine, including: (a) Modification and Amendment, dated and effective December 28, 1970 (b) Second Modification and Amendment, dated and effective August 22, 1974 (c) Agreement and Partial Surrender and Release, dated and effective October 13, 1980 (d) Amendment, dated and effective January 1, 1983 (e) Amendment, dated and effective January 1, 1986	(C)

Table of Contents

Exhibit No.	Description	Note
	(f) Amendment, dated and effective January 1, 1991	
	(g) Agreement of Consent, dated and effective October 27, 1994	
	(h) Acceptance by Pine Valley Coal Company, Inc., dated and effective October 31, 1994	
	(i) Instrument of Assignment, dated October 28, 1994, effective October 31, 1994	
	(j) Amendment, dated and effective October 31, 1994	
10.22	Lease between Beaver Coal Corporation, lessor, and Wolf Run Mining Company (f/k/a Anker West Virginia Mining Company), ICG Beckley, LLC (successor-in-interest to New River Company), lessee, of Beckley Mine, including:	(C)
	(a) Amendment, dated and effective August 1, 1975	
	(b) Amendment, dated and effective August 1, 1986	
	(c) Amendment, dated and effective August 1, 1991	
	(d) Acceptance by Pine Valley Coal Company, Inc., dated and effective October 31, 1994	
	(e) Agreement of Consent, dated and effective October 28, 1994	
	(f) Instrument of Assignment, dated October 28, 1994 and effective October 31, 1994	
	(g) Option to Lease, dated April 1, 1995	
10.23	Lease between Douglas Coal Company, lessor, and Vindex Energy Corp. (assigned from Patriot Mining Company, Inc.), lessee, of Island and Douglas Mine, including:	(C)
	(a) Option to Lease, dated May 27, 1994	
	(b) Guarantee, dated and effective May 1994	
	(c) Memorandum of Lease, dated and effective September 21, 1995	
	(d) Assignment, dated June 17, 2006	

10.25	Sublease between Reserve Coal Properties, sublessors, and Patriot Mining Company, sublessee, of Sycamore No. 2 Mine	(C)
10.27	Contract for Sale and Purchase of Coal dated July 1, 1980, between City of Springfield, Illinois and, ICG Illinois, LLC (assigned from Turis Coal Company), amended by: (a) Amendment dated March 4, 1986, effective January 1, 1986 (b) Second Amendment dated April 22, 1986, effective January 1, 1986 (c) Modification dated and effective June 8, 1987 (d) Modification dated and effective November 4, 1988 (e) Amendment dated and effective January 1, 1989 (f) Amendment dated March 20, 1992, effective January 1, 1992 (g) Amendment dated March 21, 1995, effective January 1, 1995 (h) Amendment dated May 10, 1996, effective May 1, 1996 (i) Amendment dated August 20, 1998, effective January 1, 1998 (j) Amendment dated May 30, 2001, effective January 1, 2001 (k) Letter dated October 8, 2004 assigning to ICG Illinois, LLC	(B)

Table of Contents

Exhibit No.	Description	Note
10.28‡	Coal Supply Agreement, dated as of April 1, 1992, between Hunter Ridge Coal Company (f/k/a Anker Energy Corporation) and Logan Generating Company (formerly Keystone Energy Service Company, L.P.), amended by: (a) First Amendment, effective as of September 1, 1995 (b) Second Amendment, effective as of March 15, 2002 (c) Third Amendment, effective as of October 31, 2004 (d) Coal Price Adjustment Agreement, effective as of October 31, 2004	(G)
10.29‡	Coal Sales Agreement, dated as of February 17, 2006, between Wolf Run Mining Company (f/k/a Anker West Virginia Mining Company, Inc.) and Allegheny Energy Supply Company, LLC and Monongahela Power Company	(G)
10.30	Amendment No. 1 to the Second Amended and Restated Credit Agreement, dated as of January 31, 2007, among ICG, LLC, as borrower, International Coal Group, Inc. and certain of its subsidiaries as guarantors, the lenders party thereto, J.P. Morgan Chase Securities Inc. and UBS Securities LLC, as joint lead arrangers and joint bookrunners, JPMorgan Chase Bank, N.A. and CIT Capital USA Inc., as co-syndication agents, Bank of America, N.A. and Wachovia Bank, N.A., as co-documentation agents, JPMorgan Chase Bank and Bank of America, N.A., as issuing banks, UBS Loan Finance LLC, as swingline lender, and UBS AG, Stamford Branch, as issuing bank, as administrative agent and as collateral agent for the lenders	(I)
10.31	Amendment No. 3 to the Second Amended and Restated Credit Agreement, dated as of February 20, 2009, among ICG, LLC, as borrower, International Coal Group, Inc. and certain of its subsidiaries as guarantors, the lenders party thereto, J.P. Morgan Chase Securities Inc. and UBS Securities LLC, as joint lead arrangers and joint bookrunners, JPMorgan Chase Bank, N.A. and CIT Capital USA Inc., as co-syndication agents, Bank of America, N.A. and Wachovia Bank, N.A., as co-documentation agents, JPMorgan Chase Bank and Bank of America, N.A., as issuing banks, UBS Loan Finance LLC, as swingline lender, and UBS AG, Stamford Branch, as issuing bank, as administrative agent and as collateral agent for the lenders	(N)

10.32	International Coal Group, Inc. Executive Severance Plan	(I)
10.33	International Coal Group Inc. Director Compensation Plan	(I)
10.34‡	Coal Lease Agreement Between Tygart Resources, Inc. and Pittsburgh Ligionier, Inc., Lessors and Rocking Chair Energy Company, LLC, Lessees, including (a) Assignment and Consent Agreement dated March 28, 2007 by and between Tygart Resources, Inc. and Pittsburgh Ligionier, Inc, Rocking Chair Energy Company, LLC, and Wolf Run Mining Company (b) Amendment No. 1 to Lease Agreement made effective as of April 1, 2007 by and between Tygart Resources, Inc. and Pittsburgh Ligionier, Inc., Lessors and Rocking Chair Energy Company, LLC and Wolf Run Mining Company (c) Corporate Guaranty of International Coal Group, Inc. dated as of April 1, 2007	(I)
10.35‡	Lease and Sublease Agreement between Penn Virginia Operating Co., LLC, lessor, and ICG Knott County, LLC (assigned from Greymont Mining Corp.), lessee, as amended by First Amendment to Lease and Sublease Agreement, dated November 11, 2005 and letter agreement dated February 12, 2007.	(L)
10.36‡	Coal Facility Lease and Operating Agreement, dated July 7, 2005, between Loadout LLC, lessor, and ICG Knott County, LLC (assigned from Elk Ridge, Inc.), lessee, as amended by First Amendment to Coal Facility Lease and Operating Agreement, dated November 11, 2005.	(L)
10.37	International Coal Group, Inc. Director Compensation Plan (as amended 2007)	(K)
10.38	Second Amendment and Limited Waiver to the Second Amended and Restated Credit Agreement, dated as of July 31, 2007, among ICG, LLC, as borrower, International Coal Group, Inc. and certain of its subsidiaries as guarantors, the lenders party thereto, J.P. Morgan Chase Securities Inc. and UBS Securities LLC, as joint lead arrangers and joint bookrunners, JPMorgan Chase Bank, N.A. and CIT Capital USA Inc., as co-syndication agents, Bank of America, N.A. and Wachovia Bank, N.A., as co-documentation agents, JPMorgan Chase Bank and Bank of America, N.A. as issuing banks, UBS Loan Finance LLC, as swingline lender, and UBS AG, Stamford Branch, as issuing bank, as administrative agent and as collateral agent for the lenders	(J)
10.39‡	Amended and Restated Coal Lease dated as of May 27, 2008 by and between Dulcet Acquisition LLC, as lessor, and Powdul Acquisition LLC, as lessee	(M)

10.40	Form of Non-Employee Director Restricted Share Unit Agreement	(O)
11.1	Statement regarding Computation of Earnings Per Share	(O)
21.1	List of Subsidiaries	(O)
23.1	Consent of Deloitte & Touche, LLP	(O)
24.1	Power of attorney, dated February 27, 2009	(O)
31.1	Certification of the Chief Executive Officer	(O)
31.2	Certification of the Principal Financial Officer	(O)
32.1	Certification Pursuant to § 906 of the Sarbanes-Oxley Act of 2002	(O)

Table of Contents

(A) Previously filed as an exhibit to International Coal Group, Inc.'s Registration Statement on Form S-1 (Reg. No. 333-124393), filed on April 28, 2005 and incorporated herein by reference.
(B) Previously filed as an exhibit to Amendment No. 1 to International Coal Group, Inc.'s Registration Statement on Form S-1 (Reg. No. 333-124393), filed on June 15, 2005 and incorporated herein by reference.
(C) Previously filed as an exhibit to Amendment No. 2 to International Coal Group, Inc.'s Registration Statement on Form S-1 (Reg. No. 333-124393), filed on June 30, 2005 and incorporated herein by reference.
(D) Previously filed as an exhibit to Amendment No. 3 to International Coal Group, Inc.'s Registration Statement on Form S-1 (Reg. No. 333-124393), filed on September 28, 2005 and incorporated herein by reference.
(E) Previously filed as an exhibit to Amendment No. 4 to International Coal Group, Inc.'s Registration Statement on Form S-1 (Reg. No. 333-124393), filed on October 24, 2005 and incorporated herein by reference.
(F) Previously filed as an exhibit to Amendment No. 5 to International Coal Group, Inc.'s Registration Statement on Form S-1 (Reg. No. 333-124393), filed on November 9, 2005 and incorporated herein by reference.
(G) Previously filed as an exhibit to Amendment No. 6 to International Coal Group, Inc.'s Registration Statement on Form S-1 (Reg. No. 333-124393), filed on November 14, 2005 and incorporated herein by reference.
(H) Previously filed as an exhibit to International Coal Group, Inc.'s Current Report on Form 8-K, filed on June 26, 2006 and incorporated herein by reference.
(I) Previously filed as an exhibit to International Coal Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2006, filed on March 1, 2007, and incorporated herein by reference.
(J) Previously filed as an exhibit to International Coal Group, Inc.'s Current Report on Form 8-K, filed on July 31, 2007, and incorporated herein by reference.
(K) Previously filed as an exhibit to International Coal Group, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, filed on May 8, 2007, and incorporated herein by reference.
(L) Previously filed as an exhibit to International Coal Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2007, filed on February 29, 2008 and incorporated herein by reference.
(M) Previously filed as an exhibit to International Coal Group Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed on August 8, 2008, and incorporated herein by reference.
(N) Previously filed as an exhibit to International Coal Group Inc.'s Current Report of Form 8-K, filed on February 23, 2009, and incorporated herein by reference.
(O) Filed herewith.
‡ Confidential treatment requested as to certain portions that have been omitted and filed separately with the Securities and Exchange Commission.