PEABODY ENERGY CORP
Form 10-K
February 28, 2008

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

Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2007

or

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

Commission File Number 1-16463

Peabody Energy Corporation
(Exact name of registrant as specified in its charter)

Delaware	**13-4004153**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
701 Market Street, St. Louis, Missouri	**63101**
(Address of principal executive offices)	*(Zip Code)*

(314) 342-3400
Registrant s telephone number, including area code

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, par value $0.01 per share	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

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

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

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 þ No o

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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

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

Aggregate market value of the voting stock held by non-affiliates (shareholders who are not directors or executive officers) of the Registrant, calculated using the closing price on June 29, 2007: Common Stock, par value $0.01 per share, $12.8 billion.

Number of shares outstanding of each of the Registrant s classes of Common Stock, as of February 15, 2008: Common Stock, par value $0.01 per share, 271,009,658 shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company s Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company s 2008 Annual Meeting of Stockholders (the Company s 2008 Proxy Statement) are incorporated by reference into Part III hereof. Other documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

This report includes statements of our expectations, intentions, plans and beliefs that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 and are intended to come within the safe harbor protection provided by those sections. These statements relate to future events or our future financial performance, including, without limitation, the section captioned Outlook. We use words such as anticipate, believe, expect, may, project, should, estimate, or similar words to identify forward-looking statements.

Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings, and sources of funding are forward-looking statements and speak only as of the date of this report. These forward-looking statements are based on numerous assumptions that we believe are reasonable, but are subject to a wide range of uncertainties and business risks and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ materially are:

ability to renew sales contracts;

reductions of purchases by major customers;

transportation performance and costs, including demurrage;

geology, equipment and other risks inherent to mining;

impact of weather on demand, production and transportation;

legislation, regulations and court decisions or other government actions;

new environmental requirements affecting the use of coal, including mercury and carbon dioxide related limitations;

availability, timing of delivery and costs of key supplies, capital equipment or commodities such as diesel fuel, steel, explosives and tires;

replacement of coal reserves;

price volatility and demand, particularly in higher-margin products and in our trading and brokerage businesses;

performance of contractors, third-party coal suppliers or major suppliers of mining equipment or supplies;

negotiation of labor contracts, employee relations and workforce availability;

availability and costs of credit, surety bonds and letters of credit;

credit and performance risks associated with customers, suppliers, trading and financial counterparties;

the effects of acquisitions or divestitures, including the spin-off of Patriot Coal Corporation;

economic strength and political stability of countries in which we have operations or serve customers;

risks associated with our Btu conversion or generation development initiatives;

risks associated with the conversion of our information systems;

growth of U.S. and international coal and power markets;

coal s market share of electricity generation;

the availability and cost of competing energy resources;

future worldwide economic conditions;

changes in postretirement benefit and pension obligations;

successful implementation of business strategies;

the effects of changes in currency exchange rates, primarily the Australian dollar;

inflationary trends, including those impacting materials used in our business;

interest rate changes;

litigation, including claims not yet asserted;

terrorist attacks or threats;

impacts of pandemic illnesses; and

other factors, including those discussed in Legal Proceedings, set forth in Item 3 of this report and Risk Factors, set forth in Item 1A of this report.

When considering these forward-looking statements, you should keep in mind the cautionary statements in this document and in our other Securities and Exchange Commission (SEC) filings. These forward-looking statements speak only as of the date on which such statements were made, and we undertake no obligation to update these statements except as required by federal securities laws.

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Note: The words we, our, Peabody or the Company as used in this report, refer to Peabody Energy Corporat or its applicable subsidiary or subsidiaries. Unless otherwise noted herein, disclosures in this Annual Report on Form 10-K relate only to our continuing operations. Our discontinued operations, which were spun-off to stockholders in the fourth quarter of 2007, consist of portions of our Eastern U.S. Mining operations business segment.

PART I

Item 1. *Business.*

Overview

We are the largest private-sector coal company in the world. During the year ended December 31, 2007, we sold 237.8 million tons of coal. During this period, we sold coal to over 340 electricity generating and industrial plants in 19 countries. Our coal products fuel approximately 10% of all U.S. electricity generation and 2% of worldwide electricity generation. At December 31, 2007, we had 9.3 billion tons of proven and probable coal reserves.

We own majority interests in 31 coal mining operations located in the U.S and Australia. Additionally, we own a minority interest in one Venezuelan operating mine through a joint venture arrangement. We shipped 192.3 million tons from our 20 U.S. mining operations and 21.4 million tons from our 11 Australia operations in 2007. We shipped 84% of our U.S. mining operations coal sales volume from the western United States during the year ended December 31, 2007 and the remaining 16% from the eastern United States. Most of our production in the western United States is low-sulfur coal from the Powder River Basin. Our overall Western U.S. coal production has increased from 128.4 million tons in 2002 to 161.5 million tons during 2007, a compounded annual growth rate of 4.7%. In the West, we own and operate mines in Arizona, Colorado, New Mexico and Wyoming. In the East, we own and operate mines in Illinois and Indiana. We own six mines in Queensland, Australia, and five mines in New South Wales, Australia. Our Australian production includes both low-sulfur domestic and export thermal coal and metallurgical coal. The export thermal and metallurgical coal is predominantly shipped to customers in the Asia-Pacific region. We generated 89% of our global production for the year ended December 31, 2007 from non-union mines.

For the year ended December 31, 2007, 85% of our sales (by volume) were to U.S. electricity generators, 13% were to customers outside the United States and 2% were to the U.S. industrial sector. Approximately 94% of our coal sales during the year ended December 31, 2007 were under long-term (one year or greater) contracts. Our sales backlog, including backlog subject to price reopener and/or extension provisions, was nearly one billion tons as of December 31, 2007, representing more than four years of current production in backlog. Contracts in backlog have remaining terms ranging from one to 17 years. We are targeting 2008 production of 220 to 240 million tons and total sales volume of 240 to 260 million tons, including 8 to 10 million tons of metallurgical coal. As of December 31, 2007, our unpriced 2008 volumes for planned produced tonnage were 5 to 10 million U.S. tons and 9 to 10 million Australia tons. Our total unpriced planned production for 2009 is approximately 80 to 90 million tons in the United States and 17 to 20 million tons in Australia.

Our mining operations consist of three principal operating segments: Western U.S. Mining, Eastern U.S. Mining, and Australian Mining. In addition to our mining operations, we market, broker and trade coal through our Trading and Brokerage Operations segment. Our total tons traded were 166.5 million for the year ended December 31, 2007. In response to growing international markets, we established an international trading group in 2006 and added a trading operations office in Europe in early 2007. We also have a business development, sales and marketing office in Beijing, China to pursue potential long-term growth opportunities there. Our other energy-related commercial activities include the development of mine-mouth coal-fueled generating plants, the management of our vast coal reserve and real estate holdings, and Btu Conversion technologies, which are designed to convert coal to natural gas

and transportation fuels.

For financial information regarding each of our operating segments, see Note 24 to our consolidated financial statements.

Discontinued Operations

On October 31, 2007, we spun-off portions of our Eastern U.S. Mining operations business segment to form Patriot Coal Corporation (Patriot). We distributed Patriot stock to our stockholders at a ratio of one share of Patriot stock for every 10 shares of Peabody stock held on the record date of October 22, 2007. Our results for all periods presented reflect Patriot as a discontinued operation. The spin-off included eight company-operated mines, two majority-owned joint venture mines, and numerous contractor operated mines serviced by eight coal preparation facilities along with 1.2 billion tons of proven and probable coal reserves. Prior to the spin-off, we received necessary regulatory approvals including a private letter ruling on the tax-free nature of the transaction from the Internal Revenue Service.

History

Peabody, Daniels and Co. was founded in 1883 as a retail coal supplier, entering the mining business in 1888 as Peabody & Co. with the opening of our first coal mine in Illinois. In 1926, Peabody Coal Company was listed on the Chicago Stock Exchange and, beginning in 1949, on the New York Stock Exchange.

In 1955, Peabody Coal Company, primarily an underground mine operator, merged with Sinclair Coal Company, a major surface mining company. Peabody Coal Company was acquired by Kennecott Copper Company in 1968. The company was then sold to Peabody Holding Company in 1977, which was formed by a consortium of companies.

During the 1980s, Peabody grew through expansion and acquisition, opening the North Antelope Mine in Wyoming s coal-rich Powder River Basin in 1983 and the Rochelle Mine in 1985.

In July 1990, Hanson, PLC acquired Peabody Holding Company. In the 1990s, Peabody continued to grow through expansion and acquisitions. In February 1997, Hanson spun off its energy-related businesses, including Eastern Group and Peabody Holding Company, into The Energy Group, plc. The Energy Group was a publicly traded company in the United Kingdom and its American Depository Receipts (ADRs) were publicly traded on the New York Stock Exchange.

In May 1998, Lehman Brothers Merchant Banking Partners II L.P. and affiliates (Merchant Banking Fund), an affiliate of Lehman Brothers Inc. (Lehman Brothers), purchased Peabody Holding Company and its affiliates, Peabody Resources Limited and Citizens Power LLC in a leveraged buyout transaction that coincided with the purchase by Texas Utilities of the remainder of The Energy Group. In August 2000, Citizens Power, our subsidiary that marketed and traded electric power and energy-related commodity risk management products, was sold to Edison Mission Energy and in January 2001, we sold our Peabody Resources Limited (in Australia) operations to Coal & Allied, a subsidiary of Rio Tinto Limited.

In April 2001, we changed our name to Peabody Energy Corporation, reflecting our position as a premier energy supplier. In May 2001, we completed an initial public offering of common stock, and our shares began trading on the New York Stock Exchange under the ticker symbol BTU, the globally recognized symbol for energy.

In April 2004, we acquired coal operations from RAG Coal International AG, expanding our presence in both Australia and Colorado. In December 2004, we completed the purchase of a 25.5% equity interest in Carbones del Guasare from RAG Coal International, S.A. Carbones del Guasare, a joint venture with Anglo American plc and a Venezuelan governmental partner, operates Venezuela s largest coal mine, the Paso Diablo Mine in northwestern Venezuela. In October 2006, we expanded our presence in Australia with the acquisition of Excel Coal Limited

(Excel), an independent coal company in Australia. The Excel acquisition included operating and development-stage mines, along with proven and probable coal reserves of up to 500 million tons.

On October 31, 2007, we spun-off portions of our Eastern U.S. Mining operations business segment to form Patriot Coal Corporation as noted above. The spin-off included eight company-operated mines, two majority-owned joint venture mines, and numerous contractor operated mines serviced by eight coal preparation facilities along with 1.2 billion tons of proven and probable coal reserves.

We have transformed in recent years from a high-sulfur, high-cost coal company to a predominately low sulfur, low-cost coal producer, marketer / trader of coal and manager of vast natural resources through organic growth, acquisitions and strategic operational restructuring. We operate under four core strategies to achieve growth. These include executing the basics of best-in-class safety, operations and marketing; capitalizing on organic growth opportunities; expanding in high-growth global markets; and participating in new generation and Btu Conversion technologies to convert coal into natural gas, liquids and hydrogen. Through these strategies, in 2008, we are focused on several key areas to enhance shareholder value amid the multiple markets we operate: 1) improving productivity and costs, utilizing prior-year investments and ongoing operations improvement programs; 2) expanding access to high-growth, high-margin markets; 3) improving capital efficiency; 4) pursuing long-term operating, trading and joint-venture opportunities in China, Mongolia and Mozambique; and 5) advancing clean coal projects, including Btu Conversion initiatives.

Mining Operations

We conduct our mining business through three principal mining operating segments: Western U.S. Mining, Eastern U.S. Mining, and Australian Mining. Our Western U.S. Mining Operations consist of our Powder River Basin, Southwest and Colorado operations, and our Eastern U.S. Mining Operations consist of our Midwest operations. The principal business of our U.S. Mining segments is the mining, preparation and sale of steam coal, sold primarily to electric utilities. Internationally, we operate metallurgical and steam coal mines in Queensland, Australia and New South Wales, Australia and have a 25.5% investment in a Venezuelan mine. All of our operating segments are discussed in Note 24 to our consolidated financial statements.

The following describes the operating characteristics of the principal mines and reserves of each of our business units and affiliates. The maps below show mine locations as of December 31, 2007. The U.S. map does not include our El Segundo Mine in New Mexico, which is expected to begin operations in mid-2008. All of our mining operations are owned and managed by our subsidiaries. The subsidiary that manages a particular mining operation is not necessarily the same as the subsidiary or subsidiaries which own the assets utilized in that mining operation. Unless otherwise indicated, we own 100% of the subsidiary that manages the respective mining operations or owns the related assets.

U.S. Mining Operations

Powder River Basin Operations

We control approximately 3.3 billion tons of proven and probable coal reserves in the Southern Powder River Basin, the largest and fastest growing major U.S. coal-producing region. We manage three low-sulfur, non-union surface mining complexes in Wyoming that sold 139.8 million tons of coal during the year ended December 31, 2007, or approximately 59% of our total coal sales volume. The North Antelope Rochelle and Caballo Mines are serviced by both major western railroads, the Burlington Northern Santa Fe (BNSF) Railway and the Union Pacific Railroad. The Rawhide Mine is serviced by the BNSF Railway.

Our Wyoming Powder River Basin reserves are classified as surface mineable, subbituminous coal with seam thickness varying from 60 to 115 feet. The sulfur content of the coal in current production ranges from 0.2% to 0.4% and the heat value ranges from 8,300 to 8,800 Btu s per pound.

North Antelope Rochelle Mine

The North Antelope Rochelle Mine is located 65 miles south of Gillette, Wyoming. This mine is the largest in the world, selling 91.5 million tons of compliance coal (defined as having sulfur dioxide content of 1.2 pounds or less per million Btu) during 2007. The North Antelope Rochelle Mine produces premium quality coal with a sulfur content averaging 0.2% and a heat value ranging from 8,600 to 8,800 Btu per pound. The North Antelope Rochelle Mine produces the lowest sulfur coal in the United States, using three draglines along with five overburden truck-and-shovel fleets. During 2007 we erected a new dragline and completed an in-pit crusher/conveyor at North Antelope Rochelle. These projects, combined with the completion of new blending and loading facilities in the first half of 2008, are designed to lower our cost structure by reducing reliance on truck fleets, while also increasing capacity.

Caballo Mine

The Caballo Mine is located 20 miles south of Gillette, Wyoming. During 2007, it sold 31.2 million tons of compliance coal. Caballo is a cast/dozer/truck-and-shovel assist operation with a coal handling system that includes two 12,000-ton silos and two 11,000-ton silos. The Caballo Mine produces compliance coal with a sulfur content averaging 0.36% and a heat value averaging 8,500 Btu per pound.

Rawhide Mine

The Rawhide Mine is located 10 miles north of Gillette, Wyoming. During 2007, it sold 17.1 million tons of compliance coal. Rawhide is a cast/dozer-push/truck-and-shovel assist operation with a coal handling system that includes two 12,000-ton silos and four 11,000-ton silos. The Rawhide Mine produces compliance coal with a sulfur content averaging 0.37% and a heat value averaging 8,300 Btu per pound.

Southwest Operations

We own four coal mines in our Southwest operations, two in Arizona and two in New Mexico. Kayenta, in Arizona, and Lee Ranch, in New Mexico, are both in operation. The Black Mesa Mine in Arizona suspended operations as of December 31, 2005 and the El Segundo Mine in New Mexico is scheduled to begin production in mid-2008. We control 1.0 billion tons of proven and probable coal reserves in our Southwest operations.

Kayenta Mine

The Kayenta Mine, located on the Navajo Nation and Hopi Tribe lands in Arizona, uses four draglines in three mining areas. It sold approximately 7.9 million tons of coal during 2007 and supplies primarily bituminous compliance coal under a long-term coal supply agreement to an electricity generating station in the region. The Kayenta Mine coal is crushed, then carried 17 miles by conveyor belt to storage silos where it is loaded onto a private rail line and transported 83 miles to the Navajo Generating Station, operated by the Salt River Project near Page, Arizona. The mine and railroad were designed to deliver coal exclusively to the power plant, which has no other source of coal. The Navajo coal supply agreement extends until 2011. Hourly workers at this mine are members of the United Mine Workers of America (UMWA) under a contract that extends through 2013.

Lee Ranch Mine

The Lee Ranch Mine, located near Grants, New Mexico, sold approximately 5.8 million tons of subbituminous medium sulfur coal during 2007. Lee Ranch shipped the majority of its coal to two customers in Arizona and New Mexico under coal supply agreements extending until 2020 and 2014, respectively. Lee Ranch is a non-union surface mine that uses a combination of dragline and truck-and-shovel mining techniques and ships coal to its customers via the BNSF Railway.

El Segundo Mine

The El Segundo Mine, located near Grants, New Mexico, is currently under development and is expected to start producing subbituminous medium sulfur coal in mid-2008. We executed a 19 year coal supply agreement that serves as the mine s base-load contract. El Segundo is expected to be a non-union surface mine that uses truck-and-shovel mining techniques and ships coal to its customers via the BNSF Railway.

Colorado Operations

We control approximately 0.2 billion tons of proven and probable coal reserves and currently have one operating mine in the Colorado Region.

Twentymile Mine

The Twentymile Mine is located in Routt County, Colorado, and sold 7.9 million tons of compliance, low-sulfur, steam coal to customers throughout the United States during 2007. This mine uses both longwall and continuous mining equipment. Our Twentymile Mine is non-union and has been one of the largest underground mines in the United States. Approximately 75% of all coal shipped is loaded on the Union Pacific railroad; the remainder is hauled by truck to the nearby Hayden Generating Station, operated by the Public Service of Colorado, under a coal supply agreement that extends until 2011.

Midwest Operations

Our Midwest operations consist of 13 mines in the Illinois Basin. We control approximately 3.7 billion tons of proven and probable coal reserves in the Midwest. In 2007, these operations collectively sold 30.9 million tons of coal, more than any other Midwestern coal producer. We ship coal from these mines primarily to electricity generators in the Midwest and to industrial customers for power generation.

Gateway Mine

The Gateway Mine is a non-union underground mine located in Randolph County, Illinois. During 2007, the Gateway Mine sold 2.7 million tons of steam coal.

Air Quality Mine

The Air Quality Mine is an underground mine located near Monroe City, Indiana that sold 2.0 million tons of compliance coal in 2007. The Air Quality Mine has a non-union workforce.

Farmersburg Mine

The Farmersburg Mine is a surface mine located in Vigo and Sullivan counties in Indiana that sold 3.5 million tons of medium sulfur coal in 2007. The Farmersburg Mine has a non-union workforce.

Francisco Mine Complex

The Francisco Mine Complex, which has both an underground and surface mine, is located in Gibson County, Indiana and sold 3.0 million tons of medium sulfur coal in 2007. The Francisco Mine Complex has a non-union workforce.

Somerville Mine Complex

The Somerville Mine Complex consists of three surface mines located in Gibson County, Indiana. These mines collectively sold 8.5 million tons of medium sulfur coal in 2007. The Somerville Mine Complex has a non-union workforce.

Viking Mine

The Viking Mine is a surface mine located in Indiana that sold 1.7 million tons of medium sulfur coal in 2007. The Viking Mine has a non-union workforce.

Miller Creek Mine

The Miller Creek Mine is a surface mine located in Indiana that sold 1.6 million tons of medium sulfur coal in 2007. The Miller Creek Mine has a non-union workforce.

Vermilion Grove-Riola Mine Complex

Vermilion Grove is a portal of the Riola Mine, an underground mine located in east central Illinois that sold 1.4 million tons of medium sulfur coal in 2007. Vermilion Grove has a non-union workforce.

Wildcat Hills Mine Complex

The Wildcat Hills Mine Complex, which has both an underground and surface mine, is located in Gallatin and Saline counties in southern Illinois. During 2007, these mines sold 2.9 million tons of medium sulfur coal that is primarily shipped by barge to downriver utility plants. The Wildcat Hills Mine Complex has a non-union workforce.

Willow Lake Mine

The Willow Lake Mine is an underground mine in Southern Illinois. During 2007, the mine sold 3.6 million tons of medium sulfur coal that is primarily shipped by barge to downriver utility plants. The hourly workforce at the Willow Lake Mine is represented under an International Brotherhood of Boilermakers labor agreement. A new labor agreement was signed in 2007, which will expire April 15, 2011.

Australian Mining Operations

We manage six mines in Queensland, Australia, and five mines in New South Wales, Australia. During 2007, our Australian operations sold 21.4 million tons of coal, 8.7 millions tons of which were metallurgical coal. Coal from the Queensland mines is shipped via rail and truck from the mine to the Dalrymple Bay Coal Terminal and the Ports of Gladstone and Brisbane, where the coal is loaded onto ocean-going vessels. Coal from the New South Wales mines is shipped via rail and truck from the mine to domestic customers and to the Ports of Newcastle and Kembla. The majority of sales from our Australian mines are denominated in U.S. dollars. Our Australian mines operate with site-specific collective bargaining labor agreements. Our Australian operations control 1.1 billion tons of proven and probable coal reserves.

Wilkie Creek Mine

The Wilkie Creek Mine, located in Queensland, Australia, is a surface, truck-and-shovel operation. In 2007, the Wilkie Creek Mine sold 2.4 million tons of steam coal, all of which was sold to the Asia export market through the Port of Brisbane.

Burton Mine

The Burton Mine, located in Queensland, Australia, is a surface mine using the truck-and-shovel terrace mining technique. We own 95% of the Burton operation and the remaining 5% interest is owned by the contract miner that operates on reserves we control. During 2007, we sold 3.0 million tons of metallurgical coal and 0.2 million tons of steam coal from the Burton Mine through the Dalrymple Bay Coal Terminal.

Millennium Mine

The Millennium Mine, located in Queensland, Australia, is a new surface operation utilizing truck-and-shovel mining methods which began operations in early 2007. We own an 85% interest in the Millennium Mine and manage the operations utilizing a contract miner. In January 2008, we formed a joint venture that provides an additional 35 million tons of high quality metallurgical coal reserves and grants to our joint venture partner a 50% ownership position in our preparation facility and associated infrastructure assets. During 2007, the Millennium Mine sold 1.0 million tons of metallurgical coal through the Dalrymple Bay Coal Terminal.

North Goonyella Mine

The North Goonyella Mine, located in Queensland, Australia, is a longwall underground operation. The North Goonyella Mine operates in a difficult geologic environment and produces a high-quality metallurgical coal product. During 2007, the North Goonyella Mine sold 1.3 million tons of metallurgical coal through the Dalrymple Bay Coal Terminal.

Eaglefield Mine

The Eaglefield Mine, located in Queensland, Australia, is a surface operation utilizing truck-and-shovel mining methods. It is adjacent to, and fulfills contract tonnages in conjunction with the North Goonyella underground mine. Coal is mined by a contractor from reserves that we control. During 2007, the Eaglefield Mine sold 1.2 million tons of metallurgical coal through the Dalrymple Bay Coal Terminal.

Baralaba Mine

The Baralaba Mine, located in Queensland, Australia, is a surface operation utilizing truck-and-shovel mining methods. The mine produces primarily pulverized coal injection (PCI) product, a substitute for metallurgical coal used primarily by steel makers. During 2007, the Baralaba Mine sold 0.4 million tons of PCI product. We own a 62.5% interest in the Baralaba Mine and manage the operations utilizing a contract miner.

Wambo Open-Cut Mine

The Wambo Open-Cut Mine, located in New South Wales, Australia, is a surface operation utilizing truck-and-shovel mining methods. During 2007, the Wambo Open-Cut Mine sold 4.4 million tons of steam coal. The coal from this mine was shipped through the Port of Newcastle. We own a 75% interest in the Wambo Open-Cut Mine and manage the operations utilizing a contract miner.

North Wambo Underground Mine

The North Wambo Underground Mine, located in New South Wales, Australia, is a longwall underground mine which was commissioned in the fourth quarter of 2007. During 2007, the North Wambo Underground Mine sold 0.3 million tons of steam coal. The coal from this mine was shipped through the Port of Newcastle. We own a 75% interest in the

Wambo Underground Mine.

Metropolitan Mine

The Metropolitan Mine, located in New South Wales, Australia, is a longwall underground operation. In 2007, the Metropolitan Mine sold 1.6 million tons of hard and semi-hard metallurgical coal. Coal shipments from this mine are to export customers through Port Kembla and to an Australian customer.

Wilpinjong Mine

The Wilpinjong Mine, located in New South Wales, Australia, is a new open-cut mine that was commissioned in late 2006. The mine produces thermal coal for export customers through the Port of Newcastle in addition to serving an Australian electricity generator. Coal is mined by a contractor from reserves that we control. During 2007, the Wilpinjong Mine sold 5.1 million tons of steam coal.

Chain Valley Mine

The Chain Valley Mine located in New South Wales, Australia, is a room and pillar underground operation. The Chain Valley Mine produces thermal coal which is sold locally to power authorities and to export customers through the Port of Newcastle. During 2007, the Chain Valley Mine sold 0.6 million tons of thermal coal for the year. We own 80% of the Chain Valley Mine.

Venezuelan Mining Operations

Our Venezuelan Operations consist of two joint ventures, including one operating mine and one coal mine development project.

Pasa Diablo Mine

We own a 25.5% interest in Carbones del Guasare, S.A., a joint venture that includes Anglo American plc and a Venezuelan governmental partner. Carbones del Guasare operates the Paso Diablo Mine in Venezuela. The Paso Diablo Mine is a surface operation in northwestern Venezuela that produces approximately 6 to 8 million tons of steam coal annually for export primarily to the United States and Europe. We are responsible for marketing our pro-rata share of sales from Paso Diablo; the joint venture is responsible for production, processing and transportation of coal to ocean-going vessels for delivery to customers.

Las Carmelitas Coal Mine Project

We own a 51.0% interest in Excelven Pty Ltd., which holds a 96.7% interest in Cosila Complejo Siderurgico Del Lago S.A. (Cosila). Cosila owns the Las Carmelitas Coal Mine Project, which has approximately 46 million tons of reserves in Venezuela. The other partners in this project include Alpha Natural Resources and Triangle Resource Fund. This project is currently in the exploratory stage. This interest was acquired in October 2006 as part of the Excel acquisition.

Export Facilities

We own a 30% interest in Dominion Terminal Associates, a coal transloading facility in Newport News, Virginia. The facility has a rated throughput capacity of approximately 20 million tons of coal per year and ground storage capacity of approximately 1.7 million tons. The facility exports both metallurgical and steam coal to primarily European and Brazilian markets. The terminal does not currently operate at its capacity.

We own a 17.7% interest in the Newcastle Coal Infrastructure Group (NCIG), which is currently constructing a coal transloading facility in New South Wales, Australia. The facility, which is expected to be completed in 2010, will have an initial stage capacity of 30 million tonnes per annum of which our share is 5.3 million tonnes, with expansion capacity of up to 60 million tonnes per annum.

Resource Management

We hold approximately 9.3 billion tons of proven and probable coal reserves and more than 475,000 acres of surface property. Our resource development group constantly reviews these reserves for opportunities to generate revenues through the sale of non-strategic coal reserves and surface land. In addition, we generate revenue through royalties from coal reserves and oil and gas rights leased to third parties, coalbed methane production and farm income from surface land under third-party contracts.

Trading and Brokerage Operations

Through our Trading and Brokerage Operations segment, we sell coal produced by our diverse portfolio of operations, broker coal sales of other coal producers both as principal and agent, trade coal, and trade freight contracts and provide transportation-related services in support of our coal trading strategy. As of December 31, 2007, we had 90 employees in our sales, trading, brokerage, marketing and transportation operations, including personnel dedicated to performing market research and contract administration.

International Expansion

In response to growing international markets, we expanded our international trading group in 2006 and added a trading operations office in Europe in 2007. The sales and marketing operations include our COALTRADE Australia operation that brokers coal in the Australia and Pacific Rim markets, and is based in Newcastle, Australia. We also have a business development, sales and marketing office in Beijing, China to pursue potential long-term growth opportunities in this market.

Long-Term Coal Supply Agreements

We currently have a sales backlog of almost one billion tons of coal, including backlog subject to price reopener and/or extension provisions, representing more than four years of current production in backlog. Contracts in backlog have remaining terms ranging from one to 17 years. In the same period in 2006, we had a sales backlog in excess of one billion tons of coal. For 2007, we sold approximately 94% of our sales volume under long-term coal supply agreements. In 2007, we sold coal to over 340 electricity generating and industrial plants in 19 countries. Our primary customer base is in the United States, although customers in the Pacific Rim and other international locations represent an increasing portion of our revenue stream.

We expect to continue selling a significant portion of our coal under long-term supply agreements. Our strategy is to selectively renew, or enter into new, long-term coal supply contracts when we can do so at prices we believe are favorable. Long-term contracts are attractive for regions where market prices are expected to remain stable, for

cost-plus arrangements serving captive electricity generating plants and for the sale of high-sulfur coal to scrubbed generating plants. To the extent we do not renew or replace expiring long-term coal supply agreements, our future sales will be subject to market fluctuations.

In January 2006, we signed a 19-year, 65-million-ton coal supply agreement with Arizona Public Service Company (APS). The contract is expected to generate revenue in excess of $1 billion. When our planned 6 million ton per year El Segundo Mine begins production in mid-2008, it will serve APS s Cholla Generating

Station near Joseph City, Arizona, and other customers. In December 2006, we signed a 10-year coal supply agreement with Tennessee Valley Authority to supply 6 million tons per year of Illinois Basin coal, some of which will be supplied by Patriot under contract with us. Coal sales under the first five years of the agreement are expected to be in excess of $1 billion. We also have a long-term coal supply agreement with Macquarie Generation in Australia, which runs through 2025 and will supply approximately 127 million tons in total.

Typically, customers enter into coal supply agreements to secure reliable sources of coal at predictable prices, while we seek stable sources of revenue to support the investments required to open, expand and maintain or improve productivity at the mines needed to supply these contracts. The terms of coal supply agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary significantly in many respects, including price adjustment features, price reopener terms, coal quality requirements, quantity parameters, permitted sources of supply, treatment of environmental constraints, extension options, force majeure, and termination and assignment provisions.

Each contract sets a base price. Some contracts provide for a predetermined adjustment to the base price at times specified in the agreement. Base prices may also be adjusted quarterly, annually or at other periodic intervals for changes in production costs and/or changes due to inflation or deflation. Changes in production costs may be measured by defined formulas that may include actual cost experience at the mine as part of the formula. The inflation/deflation adjustments are measured by public indices, the most common of which for U.S. coal is the implicit price deflator for the gross domestic product as published by the U.S. Department of Commerce. In most cases, the components of the base price represented by taxes, fees and royalties which are based on a percentage of the selling price are also adjusted for any changes in the base price and passed through to the customer. Some contracts allow the base price to be adjusted to reflect the cost of capital.

Most contracts contain provisions to adjust the base price due to new statutes, ordinances or regulations that impact our cost of performance under the agreement. Additionally, most contracts contain provisions that allow for the recovery of costs impacted by the modifications or changes in the interpretation or application of any existing statute by local, state or federal government authorities. Some agreements provide that if the parties fail to agree on a price adjustment caused by cost increases due to changes in applicable laws and regulations, either party may terminate the agreement.

Price reopener provisions are present in many of our multi-year coal contracts. These provisions may allow either party to commence a renegotiation of the contract price at various intervals. In a limited number of agreements, if the parties do not agree on a new price, the purchaser or seller has an option to terminate the contract. Under some contracts, we have the right to match prices offered to our customers by other suppliers.

Quality and volumes for the coal are stipulated in coal supply agreements, and in some limited instances buyers have the option to vary annual or monthly volumes if necessary. Variations to the quality and volumes of coal may lead to adjustments in the contract price. Most coal supply agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat (Btu), sulfur, and ash content, and for grindability and ash fusion temperature. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts. Coal supply agreements typically stipulate procedures for quality control, sampling and weighing. In the eastern United States, some of our customers require that the coal is sampled and weighed at the destination, whereas in the western United States samples and weights are usually taken at the shipping source.

Contract provisions in some cases set out mechanisms for temporary reductions or delays in coal volumes in the event of a force majeure, including events such as strikes, adverse mining conditions or serious transportation problems that affect the seller or unanticipated plant outages that may affect the buyer. More recent contracts stipulate that this

tonnage can be made up by mutual agreement. Buyers often negotiate similar clauses covering changes in environmental laws. We often negotiate the right to supply coal that complies with a new environmental requirement to avoid contract termination. Coal supply agreements typically contain termination clauses if either party fails to comply with the terms and conditions of the contract, although most termination provisions provide the opportunity to cure defaults.

In some of our contracts, we have a right of substitution, allowing us to provide coal from different mines, including third-party production, as long as the replacement coal meets the contracted quality specifications and will be sold at the same delivered cost per million Btu.

Transportation

Coal consumed in the U.S. is usually sold at the mine and transportation costs are borne by the purchaser. Export coal is usually sold at the loading port, with purchasers paying ocean freight. Producers usually pay shipping costs from the mine to the port, including any demurrage costs (fees paid to third-party shipping companies for loading time that exceeded the stipulated time).

The majority of our sales volume is shipped by rail in the U.S., but a portion of our production is shipped by other modes of transportation, including barge, truck and ocean-going vessels. Our transportation department manages the loading of coal via these transportation modes.

Our Australian export volume (17 to 20 million tons annually) is shipped via ocean going vessels to customers. The majority of this coal reaches the loading port via rail. Our Australian domestic volume (4 to 6 million tons annually) is shipped via rail.

Approximately 12,000 unit trains are loaded each year to accommodate the coal shipped by our mines overall. A unit train generally consists of 100 to 150 cars, each of which can hold 100 to 120 tons of coal. We believe we have good relationships with rail carriers and barge companies due, in part, to our modern coal-loading facilities and the experience of our transportation coordinators.

Suppliers

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

Technical Innovation

To support the continued growth and globalization of our businesses, we have completed the U.S. implementation of a project to convert our existing information systems across the major business processes to an integrated Enterprise Resource Planning (ERP) information technology system provided by SAP AG. The project establishes a single global information platform for us and will enable standard processes and real-time capabilities in Finance, Materials, Maintenance, Human Resources, Sales, Production, Transportation and Quality across all of our U.S. operations. A future conversion of all of our Australian systems onto the same single global platform is planned for 2009.

We continue to place great emphasis on the application of technical innovation to improve new and existing equipment performance. This research and development effort is typically undertaken and funded by equipment manufacturers using our input and expertise. Our engineering, maintenance and purchasing personnel work together with manufacturers to design and produce equipment that we believe will add value to the business.

During 2007, we continued to make progress toward the improvement to the performance of our dragline systems. The dragline improvement effort includes more efficient bucket design, faster cycle times, improved swing motion controls to increase component life and better monitors to enable increased payloads. Draglines were refurbished and upgraded in Wyoming and Arizona with many new design features. All draglines are equipped with stress and performance monitoring equipment.

Technology to quickly capture, analyze and transfer information regarding safety, performance and maintenance conditions at our operations is a priority. A wireless data acquisition system has been installed at the North Antelope Rochelle Mine to more efficiently dispatch mobile equipment and monitor performance and condition of all major mining equipment on a real-time basis. Plans are underway to rollout the system to other mining operations. Proprietary software for hand-held Personal Digital Assistant (PDA) devices was developed in-house, and is being used for safety observations and safety audits and underground front-line supervisor reports in the U.S.

World-class maintenance standards based on reliability centered maintenance practices are being implemented at all operations. Use of these techniques is expected to allow us to increase equipment utilization and reduce maintenance and capital spending by extending the equipment life, while minimizing the risk of premature failures. Optimized equipment strategies are being developed to define the appropriate preventative and predictive maintenance activities emphasizing work being scheduled on condition rather than time. Benefits from sophisticated analysis derived from lubrication, vibration and infrared technologies typically include lower lubrication consumption, optimum equipment performance and extended component life. Specialized maintenance reliability software was installed in 2007 to better support the definition of these equipment strategies, predict equipment condition and aid analysis necessary for better decision making for such issues as component replacement timing.

Our mines use sophisticated software to schedule and monitor trains, mine and pit blending, quality and customer shipments. This integrated software was developed in-house and provides a competitive tool to differentiate our reliability and product consistency. Our new preparation plant at the Twentymile Mine in Colorado utilizes the latest concepts in low profile design and high capacity equipment for improved maintenance practices and overall plant utilization. The process circuitry uses the current state-of-the-art large diameter heavy media cyclones and two stage fine coal cleaning with water-only cyclones and spirals to enhance process performance and yield. A number of safety and monitoring features have been incorporated in the plant including an internet-accessible camera system.

We are also involved in the commercial development and advancement of Btu Conversion technologies (see the Btu Conversion discussion that follows for more details).

Competition

The markets in which we sell our coal are highly competitive. According to the National Mining Association s 2006 Coal Producer Survey, the top 10 coal companies in the United States produced approximately 68% of total U.S. coal in 2006. Our principal U.S. competitors are other large coal producers, including Arch Coal, Inc., Rio Tinto Energy America, CONSOL Energy Inc, Foundation Coal Corporation, Patriot Coal Corporation and Massey Energy Company, which collectively accounted for approximately 49% of total U.S. coal production in 2006. Major international competitors include Rio Tinto, Anglo-American PLC, BHP Billiton, Shenhua Group, China Coal and Xstrata PLC.

A number of factors beyond our control affect the markets in which we sell our coal. Continued demand for our coal and the prices obtained by us depend primarily on the coal consumption patterns of the electricity generation and steel industries in the United States, China, India and elsewhere around the world; the availability, location, cost of transportation and price of competing coal; and other electricity generation and fuel supply sources such as natural gas, oil, nuclear and hydroelectric. Coal consumption patterns are affected primarily by the demand for electricity,

environmental and other governmental regulations, and technological developments. We compete on the basis of coal quality, delivered price, customer service and support, and reliability.

Generation Development

To maximize our coal assets and land holdings for long-term growth, we continue to pursue the development of coal-fueled generating projects in areas of the U.S. where electricity demand is strong and where there is access to land, water, transmission lines and low-cost coal. The projects involve mine-mouth generating plants using our surface lands and coal reserves. Our ultimate role in these projects could take numerous forms, including, but not limited to, equity partner, contract miner or coal lessor. The projects we are currently pursuing, as further detailed below, include the 1,600 plus-megawatt Prairie State Energy Campus in Washington County, Illinois and the 1,500-megawatt Thoroughbred Energy Campus in Muhlenberg County, Kentucky.

Because coal costs just a fraction of natural gas, mine-mouth generating plants can provide low-cost electricity to satisfy growing baseload generation demand. The plants will be designed to comply with all current clean air standards using advanced emissions control technologies. The plants, assuming all necessary permits and financing are obtained and following selection of partners and sale of a majority of the output of each plant, could be operational following a four-year construction phase.

Prairie State Energy Campus

The Prairie State Energy Campus (Prairie State), of which we own 5.06%, is a 1,600 plus-megawatt coal-fueled electricity generation project under construction in Washington County, Illinois. Prairie State will be fueled by over six million tons of coal each year produced from adjacent underground mining operations. In September 2007, a group of Midwest rural electric cooperatives and municipal joint action agencies entered into definitive agreements with our affiliate and acquired approximately 72% of the project, and in December 2007 our affiliate sold an additional 23% of Prairie State. The plant could begin generating electricity in the 2011 to 2012 timeframe.

In January 2005, the State of Illinois issued the final air permit for the electric generating station and adjoining coal mine. In August 2007, the U.S. Court of Appeals for the Seventh Circuit unanimously affirmed the issuance of Prairie State s air permit and in October 2007 the Court unanimously rejected a request for a rehearing of its prior decision. Because there was no appeal of the Court s decision, that decision upholding the permit is now final.

Thoroughbred Energy Campus

The 1,500-megawatt Thoroughbred Energy Campus (Thoroughbred) in Muhlenberg County, Kentucky is a development stage electric generating station that has received a conditional construction certificate from the Commonwealth of Kentucky. We and the Commonwealth of Kentucky defended the air permit granted to Thoroughbred in 2002 against challenges by various environmental advocacy groups, and in April 2006 we received a decision affirming the Thoroughbred air permit. Certain parties subsequently challenged the favorable decision in Kentucky state court. On August 6, 2007 the Franklin Circuit Court remanded the permit back to the Kentucky permitting agency. On August 28, 2007 we and the Commonwealth of Kentucky filed an appeal of the remand with the Kentucky Court of Appeals and on September 24, 2007 the Court granted Kentucky s motion to expedite the appeal. A decision on the appeal is expected in 2008.

Clean Coal Technology and Btu Conversion

Through our technology investments, we are taking a leading position in advancing clean coal and Btu Conversion technologies. We are involved in the following initiatives.

FutureGen Industrial Alliance

We are a founding member of the FutureGen Industrial Alliance (FutureGen), a non-profit company that is partnering with the U.S. Department of Energy (DOE) to facilitate the design, construction and operation of the world s first near-zero emissions coal-fueled power plant. In January 2008, DOE announced plans to

reconfigure FutureGen as a project with multiple carbon capture and storage sites, while some members of Congress argued in favor of the original project.

GreenGen

In December 2007, we became the only non-Chinese equity partner in GreenGen, a development-stage project in China to build a near-zero emissions coal-fueled power plant with carbon capture and storage. The US$1 billion GreenGen project is expected to use advanced coal-based technologies to generate electricity. It would be capable of hydrogen production and will advance carbon dioxide capture and storage technologies.

Coal21 Fund

We have committed to contribute for a five-year period to the Australian COAL21 Fund, which is a voluntary coal industry fund to support clean coal technology demonstration projects and research in Australia. All major coal companies in Australia have committed to this fund. The Clean Coal Technology Special Agreement Act 2007 (Queensland) provides that the amount contributed in relation to Queensland production will be expended on Queensland or National Clean Coal Technology Projects. The Act establishes a Clean Coal Council to make recommendations to the Premier on the Projects which should be funded.

National Clean Coal Fund

The Federal Labor Government has stated that it will establish a $500 million Clean Coal Fund to develop clean coal technologies in Australia. This includes funding for clean coal research, a pilot coal gasification plant, the demonstration of carbon capture and storage and a national carbon mapping and infrastructure plan. We are not contributing to this fund.

Btu Conversion

With the increase in U.S. demand for natural gas and oil based commodities, we are determining how to best participate in technologies to economically convert our coal resources to natural gas as well as liquids such as diesel fuel, gasoline and jet fuel. Our initiatives include:

An agreement with ConocoPhillips to explore development of a commercial scale coal-to-substitute natural gas (SNG) facility in the Midwest;

A minority investment in GreatPoint Energy, Inc., which is commercializing its proprietary bluegas^{tm} technology that converts coal, petroleum coke and biomass into ultra-clean pipeline quality natural gas while enabling carbon capture and storage;

An agreement to acquire a 30% interest in Econo-Power International Corporation (EPIC^{tm}), which uses air-blown gasifiers to convert coal into a synthetic gas that is ideal for industrial applications; and

A joint development agreement with Rentech, Inc. to evaluate sites in the Midwest and Montana for coal-to-liquids projects that would transform coal into diesel and jet fuel using Rentech s proprietary Fischer-Tropsch coal-to-liquids process.

Certain Liabilities

We have long-term liabilities for reclamation (also called asset retirement obligations), pensions and retiree health care. In addition, one labor contract with the UMWA (the Western Surface Agreement) and voluntary arrangements with non-union employees include long-term benefits, notably health care coverage for retired employees and future retirees and their dependents. The majority of our existing liabilities relate to our past operations, including operations spun-off with Patriot.

Asset Retirement Obligations. Asset retirement obligations primarily represent the present value of future anticipated costs to restore surface lands to productivity levels equal to or greater than pre-mining conditions, as required by applicable laws and regulations. Expense from continuing operations (which includes liability accretion and asset amortization) for the years ended December 31, 2007, 2006 and 2005

was $25.6 million, $15.8 million, and $20.3 million, respectively. As of December 31, 2007, our asset retirement obligations of $369.5 million included $337.0 million related to locations with active mining operations and $32.5 million related to locations that are closed or inactive.

Pension-Related Provisions. Pension-related costs represent the actuarially-estimated cost of pension benefits. Annual minimum contributions to the pension plans are determined by consulting actuaries based on the minimum funding standards of the Employee Retirement Income Security Act of 1974, as amended (ERISA), and an agreement with the Pension Benefit Guaranty Corporation (PBGC). Beginning on January 1, 2008, new minimum funding standards will be required by the Pension Protection Act of 2006. Net pension-related liabilities were $45.8 million as of December 31, 2007, $1.3 million of which was a current liability. Expense for the years ended December 31, 2007, 2006 and 2005 was $19.6 million, $26.3 million and $38.7 million, respectively.

Retiree Health Care. Consistent with Statement of Financial Accounting Standard (SFAS) No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions we record a liability representing the estimated cost of providing retiree health care benefits to current retirees and active employees who will retire in the future. Provisions for active employees represent the amount recognized to date, based on their service to date; additional amounts are accrued periodically so that the total estimated liability is accrued when the employee retires. Our retiree health care liabilities were $855.8 million as of December 31, 2007, $70.1 million of which was a current liability. The Patriot spin-off reduced our health care liabilities by $617.0 million. Health care expense related to the spin-off of Patriot for the years ended December 31, 2007, 2006 and 2005 was $46.6 million, $41.4 million and $35.4 million, respectively, and was included in Discontinued operations.

Under the terms of the spin-off separation agreement, Patriot is primarily liable for all obligations related to the Combined Fund, 1992 Benefit Fund and 1993 Benefit Fund. The Combined Fund and the 1992 Fund were created by federal law in 1992. These multi-employer funds provide health care benefits to a class of retirees who meet the statutory criteria. A third fund, the 1993 Benefit Fund, was established through collective bargaining and provides certain retiree health care benefits. A portion of the Combined Fund retirees was included within our Eastern U.S. Mining operations business segment and became the responsibility of Patriot in conjunction with the related spin-off. The actuarially determined liability representing the amounts anticipated to be due to the Combined Fund also became the responsibility of Patriot in the spin-off and totaled $38.4 million as of October 31, 2007. As of December 31, 2006, this obligation was $30.8 million and was reflected within liabilities of discontinued operations in the consolidated balance sheets. Expense of $2.7 million, $2.5 million and $0.9 million was recognized related to the Combined Fund for the years ended December 31, 2007, 2006 and 2005, respectively, and was included in Discontinued operations.

The Surface Mining Control and Reclamation Act Amendments of 2006 (the 2006 Act) authorizes a specified amount of federal funds to pay for these programs on a phased-in basis and other programs. To the extent that (i) the annual retiree health care funding requirement exceeds the specified amount of federal funds, (ii) Congress does not allocate additional funds to cover the shortfall, and (iii) Patriot s subsidiaries do not pay their share of the shortfall, some of our subsidiaries would be responsible for the additional costs.

Employees

As of December 31, 2007, we had approximately 7,000 employees. As of such date, approximately 27% of our hourly employees were represented by organized labor unions and generated 10% of the 2007 coal production. Relations with our employees and, where applicable, organized labor are important to our success.

We opened training centers in the midwest and western regions of the United States under our Workforce of the Future initiative. Due to our current employee demographics, a significant portion of our current hourly employees

will retire over the next decade. Our training centers are educating our workforce, particularly our most recent hires, in our rigorous safety standards, the latest in mining techniques and equipment, and the centers disseminate mining best practices across all of our operations. Our training efforts exceed minimum government standards for safety and technical expertise with the intent of developing and retaining a world-class workforce. Additionally, we are implementing a supervisor training program through our training centers

to develop both new and current supervisors, in an effort to ensure the replenishment of our operating management workforce over the next decade.

United States Labor Relations

The UMWA, under the Western Surface Agreement, represented approximately 6% of our U.S. subsidiaries hourly employees, who generated 4% of our U.S. production during the year ended December 31, 2007. An additional 7% of our U.S. subsidiaries hourly employees are represented by labor unions other than the UMWA. These employees generated 2% of our U.S. production during the year ended December 31, 2007. Hourly workers at our subsidiary s operating mine in Arizona are represented by the UMWA under the Western Surface Agreement, which is effective through September 2, 2013. Hourly workers at our Willow Lake Mine in Illinois are represented by the International Brotherhood of Boilermakers under a labor agreement that was signed in 2007 and that expires April 15, 2011.

Australia Labor Relations

The Australian coal mining industry is unionized and the majority of workers employed at our Australian Mining operations are members of trade unions. The Construction Forestry Mining and Energy Union represents our Australian subsidiary s hourly production employees. As of December 31, 2007, our Australian subsidiary s hourly employees were approximately 26% of our Australian hourly workforce and generated 29% of our total Australian production in the year then ended. Our remaining hourly workforce is employed through contract mining relationships. The labor agreements at our Metropolitan Mine were renewed in July and October 2007 and those agreements expire in 2010. The Wambo mine coal handling plant labor agreement is under negotiation and the North Goonyella Mine operates under an agreement due to expire in March 2008.

Regulatory Matters United States

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as employee health and safety, permitting and licensing requirements, 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. In addition, the industry is affected by significant legislation mandating certain benefits for current and retired coal miners. Numerous federal, state and local governmental permits and approvals are required for mining operations. We believe that we have obtained all permits currently required to conduct our present mining operations.

We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time in the industry. None of the violations to date or the monetary penalties assessed has been material.

Mine Safety and Health

Our vision is to provide a workplace that is incident free. We believe that it is our responsibility to our employees to provide a superior safety and health environment. We seek to implement this goal by: training employees in safe work practices; openly communicating with employees; establishing, following and improving safety standards; involving employees in safety processes; and recording, reporting and investigating all accidents, incidents and losses to avoid reoccurrence. A portion of the annual performance incentives for our operating units is tied to their safety performance.

Our safety performance in 2007, as measured by injury incidence rates, was 35% better than the U.S. average for our industry. During 2007, we achieved our vision of zero incidents for the whole year at five of our facilities, which contributed to our second best year ever in safety. We received multiple safety awards during the year, including the Sentinels of Safety at Farmersburg as the safest large surface coal mine in the country. Our training centers educate our employees in safety best practices and reinforce our company-wide belief that productivity and profitability follow when safety is a cornerstone of all of our operations.

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. Congress enacted The Mine Improvement and New Emergency Response Act of 2006 (The Miner Act) as a result of the increase in fatal accidents primarily at U.S. underground mines. Among the new requirements, each miner must have at least two, one-hour Self Contained Self Rescue (SCSR) devices for their use in the event of an emergency (each miner had at least one SCSR device prior to The Miner Act) and additional caches of SCSRs in the escape routes leading to the surface. Our progress in meeting these requirements has continued, and we anticipate full compliance with the new regulations in the first half of 2008 as we await shipment of new materials. The Miner Act also requires installation of wireless, two-way communication systems for miners following an accident, and mine operators must have the ability to locate each miner s location at all times. Since these technologies are not yet available, we are working with the National Institute for Occupational Safety and Health and several manufacturers to develop new systems.

Most of the states in which we operate have inspection programs for mine safety and health. 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.

Black Lung

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each U.S. coal mine operator must pay federal black lung benefits and medical expenses to claimants who are current and former employees and last worked for the operator after July 1, 1973. Coal mine operators must also make payments 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. Historically, less than 7% of the miners currently seeking federal black lung benefits are awarded these benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

Environmental Laws

We are subject to various federal and state environmental laws. Some of these laws, discussed below, place many requirements on our coal mining operations. Federal and state regulations require regular monitoring of our mines and other facilities to ensure compliance.

Surface Mining Control and Reclamation Act

In the United States, 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 U.S. surface mining as well as many aspects of deep mining. Mine operators must obtain SMCRA permits and permit renewals for mining operations from the OSM. Where state regulatory agencies have adopted federal mining programs under the act, the state becomes the regulatory authority. Except for Arizona, states in which we have active mining operations have achieved primary control of enforcement through federal authorization. In Arizona, we mine on tribal lands and are regulated by OSM because the tribes do not have SMCRA authorization.

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 re-vegetation.

The U.S. 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 we will mine. We develop mine and reclamation plans by utilizing this geologic data and

incorporating elements of the environmental data. The mine and reclamation plan incorporates the provisions of SMCRA, the state programs and the complementary environmental programs that impact coal mining. 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 of the OSM s Applicant Violator System.

Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness and technical review. Public notice of the proposed permit is given for a comment period 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 often take six months to two years to be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public has the right to comment on and otherwise engage in the permitting process, including public hearings and through intervention in the courts.

Before a SMCRA permit is issued, a mine operator must submit a bond or other form of financial security to guarantee the performance of reclamation obligations. The Abandoned Mine Land Fund, which is part of SMCRA, requires a fee on all coal produced in the U.S. The proceeds are used to rehabilitate lands mined and left unreclaimed prior to August 3, 1977 and to pay health care benefit costs of orphan beneficiaries of the Combined Fund. The fee is $0.35 per ton of surface-mined coal and $0.15 per ton of deep-mined coal, effective through September 30, 2007. Pursuant to the Tax Relief and Health Care Act of 2006, from October 1, 2007 through September 30, 2012, the fee will be $0.315 per ton of surface-mined coal and $0.135 per ton of underground mined coal. From October 1, 2012 through September 30, 2021, the fee will be reduced to $0.28 per ton of surface-mined coal and $0.12 per ton of underground mined coal.

SMCRA stipulates compliance with many other major environmental programs. These programs include the Clean Air Act; Clean Water Act; Resource Conservation and Recovery Act (RCRA); and Comprehensive Environmental Response, Compensation, and Liability Acts (CERCLA, commonly known as Superfund). Besides OSM, other Federal regulatory agencies are involved in monitoring or permitting specific aspects of mining operations. The U.S. Environmental Protection Agency (EPA) is the lead agency for States or Tribes with no authorized programs under the Clean Water Act, RCRA and CERCLA. The U.S. Army Corps of Engineers regulates activities affecting navigable waters and the U.S. Bureau of Alcohol, Tobacco and Firearms (ATF) regulates the use of explosive blasting.

We do not believe there are any matters that pose a material risk to maintaining our existing mining permits or materially hinder our ability to acquire future mining permits. It is our policy to comply in all material respects with the requirements of the SMCRA and the state and tribal laws and regulations governing mine reclamation.

Clean Air Act

The Clean Air Act and the corresponding state laws that regulate the emissions of materials into the air affect U.S. coal mining operations both directly and indirectly. Direct impacts on coal mining and processing operations may occur through the Clean Air Act permitting requirements and/or emission control requirements relating to particulate matter. The Clean Air Act indirectly, but more significantly, affects the coal industry by extensively regulating the air emissions of sulfur dioxide, nitrogen oxide, mercury and other compounds emitted by coal-based electricity generating plants.

The EPA promulgated the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) in March 2005. CAIR requires reduction of sulfur dioxide and nitrogen oxide emissions from electricity generating plants in 28 states and the District of Columbia. Substantial reductions in such emissions were already made in 1995 and 2000 under requirements of Title IV of the Clean Air Act. Once fully implemented over two rounds in 2009-2010 and 2015, CAIR is projected to reduce sulfur dioxide from power plants by approximately 73% and nitrogen oxide emissions by

approximately 61% from 2003 levels.

CAMR sought to permanently cap and reduce nationwide mercury emissions from coal-fired power plants. When fully implemented in 2018, the rule as promulgated would have reduced mercury emissions by nearly 70% according to the EPA. CAMR contained standards of performance limiting mercury emissions

from new and existing power plants and sought to create a cap-and-trade program. Some states have adopted rules that are more stringent than the federal program and other states are considering such rules.

On February 8, 2008, in a case brought by the State of New Jersey and others against the EPA, the United States Court of Appeals for the District of Columbia rendered a decision effectively vacating CAMR. If the decision stands, the EPA will have to revisit its standards regarding mercury emissions.

Implementation of CAIR, federal requirements regarding mercury emissions and related state rules could cause our customers to switch to other fuels to the extent it becomes economically preferable for them to do so. CAIR is currently under review in court on a number of grounds, including the assertion that the regulations are insufficiently stringent.

In recent years Congress has considered legislation that would require reductions in emissions of sulfur dioxide, nitrogen oxide and mercury, greater and sooner than those required by CAIR and CAMR. No such legislation has passed either house of Congress. If enacted into law, such legislation could impact the amount of coal supplied to electricity generating customers if they decide to switch to other sources of fuel whose use would result in lower emissions of sulfur dioxide, nitrogen oxide and mercury.

In September 2006, the EPA promulgated new National Ambient Air Quality Standards revising and updating the particulate matter standards issued in July 1997. The new regulations made the 24-hour standard for very fine particulate matter (PM2.5) more stringent but left the annual PM2.5 standard unchanged. They also left the 24-hour standard for PM10 (particulate matter equal to 10 microns or more) unchanged and terminated the annual PM10 standard. The change to the 24-hour PM2.5 standard is expected to affect the use of coal for electric generation, but we believe that effect cannot be quantified at this time. Lawsuits seeking to compel the EPA to adopt more stringent standards both for PM2.5 and PM10 have been filed and are pending in court. We believe the outcome of those lawsuits cannot be reliably predicted at this time. Under the rule as currently promulgated, some states will be required to change their existing implementation plans to attain and maintain compliance with the new air quality standards. Our mining operations and electricity generating customers are likely to be directly affected when the revisions to the air quality standards are implemented by the states. Such implementation could also restrict our ability to develop new mines or require us to modify our existing operations.

The Justice Department, on behalf of the EPA, has filed a number of lawsuits since November 1999, alleging that a number of electricity generators violated the new source review provisions of the Clean Air Act Amendments (NSR) at power plants in the midwestern and southern United States. Some electricity generators announced settlements with the Justice Department requiring the installation of additional control equipment on selected generating units. If the remaining electricity generators are found to be in violation, they could be subject to civil penalties and could be required to install the required control equipment or cease operations. In April 2007, the U.S. Supreme Court ruled, in Environmental Defense v. Duke Energy Corp., against a generator in an enforcement proceeding, reversing the decision of the appellate court. This decision could potentially expose numerous electricity generators to government or citizen actions based on failure to obtain NSR permits for changes to emissions sources and effectively increase the costs to them of continuing to use coal. Our customers are among the electricity generators subject to enforcement actions and if found not to be in compliance, our customers could be required to install additional control equipment at the affected plants or they could decide to close some or all of those plants. If our customers decide to install additional pollution control equipment at the affected plants, we believe we will have the ability to supply coal from the regions in which we operate to meet any new coal requirements.

The U.S. Supreme Court ruled in April 2007 in a case concerning the scope of the EPA s authority to regulate carbon dioxide emissions as a pollutant under the Clean Air Act. The decision, Massachusetts v. EPA, ruled in the context of a petition to require the EPA to issue regulations prescribing standards for carbon dioxide from new motor vehicles,

that the EPA does have such authority, and that the EPA s rejection of the petition was based on impermissible considerations. While the decision removes several major arguments the EPA had used to decline to regulate carbon dioxide emissions, it remains difficult to predict whether the EPA will issue carbon dioxide regulations and, if so, when the EPA will do so and the character of those regulations.

Clean Water Act

The Clean Water Act of 1972 affects U.S. coal mining operations by requiring effluent limitations and treatment standards for waste water discharge through the National Pollutant Discharge Elimination System (NPDES). Regular monitoring, reporting requirements and performance standards are requirements of NPDES permits that govern the discharge of pollutants into water.

States are empowered to develop and enforce in stream water quality standards. These standards are subject to change and must be approved by the EPA. Discharges must either meet state water quality standards or be authorized through available regulatory processes such as alternate standards or variances. In stream standards vary from state to state. Additionally, through the Clean Water Act section 401 certification program, states have approval authority over federal permits or licenses that might result in a discharge to their waters. States consider whether the activity will comply with its water quality standards and other applicable requirements in deciding whether or not to certify the activity.

Section 404 under the Clean Water Act requires mining companies to obtain U.S. Army Corps of Engineers permits to place material in streams for the purpose of creating slurry ponds, water impoundments, refuse areas, valley fills or other mining activities. These permits have been the subject of multiple recent court cases, the results of which may affect permitting costs or result in permitting delays.

Total Maximum Daily Load (TMDL) regulations established a process by which states designate stream segments as impaired (not meeting present water quality standards). Industrial dischargers, including coal mines, may be required to meet new TMDL effluent standards for these stream segments. States are also adopting anti-degradation regulations in which a state designates certain water bodies or streams as high quality/exceptional use. These regulations would restrict the diminution of water quality in these streams. Waters discharged from coal mines to high quality/exceptional use streams may be required to meet additional conditions or provide additional demonstrations and/or justification. In general, these Clean Water Act requirements could result in higher water treatment and permitting costs or permit delays, which could adversely affect our coal production costs or efforts.

Resource Conservation and Recovery Act

RCRA, which was enacted in 1976, affects U.S. coal mining operations by establishing cradle to grave requirements for the treatment, storage and disposal of hazardous wastes. Typically, the only hazardous materials found on a mine site are those contained in products used in vehicles and for machinery maintenance. Coal mine wastes, such as overburden and coal cleaning wastes, are not considered hazardous waste materials under RCRA.

Subtitle C of RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In a 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion materials generated at electric utility and independent power producing facilities. In May 2000, the EPA concluded that coal combustion materials do not warrant regulation as hazardous under RCRA. The EPA is retaining the hazardous waste exemption for these materials. The EPA is evaluating national non-hazardous waste guidelines for coal combustion materials placed at a mine. National guidelines for mine-fills may affect the cost of ash placement at mines.

CERCLA (Superfund)

CERCLA affects U.S. 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. Under Superfund, joint and several liabilities may be imposed on waste generators, site owners or operators and others

regardless of fault. Under the EPA s Toxic Release Inventory process, companies are required annually to report the use, manufacture or processing of listed toxic materials that exceed defined thresholds, including chemicals used in equipment maintenance, reclamation, water treatment and ash received for mine placement from power generation customers.

The Energy Policy Act of 2005

The Domenici-Barton Energy Policy Act of 2005 (EPACT) was signed by President Bush in August 2005. EPACT contains tax incentives and directed spending totaling an estimated $14.1 billion intended to stimulate supply-side energy growth and increased efficiency. In addition to rules affecting the leasing process of federal coal properties, EPACT programs and incentives include funding to demonstrate advanced coal technologies, including coal gasification; grants and a loan guarantee program to encourage deployment of advanced clean coal-based power generation technologies, including integrated gasification combined cycle (IGCC); a federal loan guarantee program for the cost of advanced fossil energy projects, including coal gasification; funding for energy research, development, demonstration and commercial application programs relating to coal and power systems; and tax incentives for IGCC, industrial gasification and other advanced coal-based generation projects, as well as for coal sold from Indian lands. Finally, certain sections of EPACT are potentially applicable to the area of Btu Conversion, such as the aforementioned fossil energy project loan guarantee program as well as a provision allowing taxpayers to capitalize 50% of the cost of refinery investments which increase the total throughput of qualified fuels including synthetic fuels produced from coal by at least 25%. In addition, EPACT requires the Secretary of Defense to develop a strategy to use fuel produced from coal, oil shale and tar sands (covered fuel) to assist in meeting the fuel requirements of the U.S. Department of Defense (DOD). The law authorizes the DOD to enter into multi-year contracts to procure a covered fuel to meet one or more of its fuel requirements and to carry out an assessment of potential locations for covered fuel sources.

Regulatory Matters Australia

The Australian mining industry is regulated by Australian federal, state and local governments with respect to environmental issues such as land reclamation, water quality, air quality, dust control, noise, planning issues (such as approvals to expand existing mines or to develop new mines), and health and safety issues. The Australian federal government retains control over the level of foreign investment and export approvals. Industrial relations are regulated under both federal and state laws. Australian state governments also require coal companies to post deposits or give other security against land which is being used for mining, with those deposits being returned or security released after satisfactory reclamation is completed.

Native Title and Cultural Heritage

Since 1992, the Australian courts have recognized that native title to lands, as recognized under the laws and customs of the Aboriginal inhabitants of Australia, may have survived the process of European settlement. These developments are supported by the Federal Native Title Act (NTA) which recognizes and protects native title, and under which a national register of native title claims has been established.

Native title rights do not extend to minerals; however, native title rights can be affected by the mining process unless those rights have previously been extinguished. Native title rights can be extinguished either by a valid act of Government (as set out in the NTA) or by the loss of connection between the land and the group of Aboriginal peoples concerned.

The NTA provides that where native title rights still exist and the mining project will affect those native title rights, it will be necessary to consult with the relevant Aboriginal group and to come to an agreement on issues such as the preservation of sacred or important sites, the employment of members of the group by the mine operator, and the payment of compensation for the effect on native title of the mining project. In the absence of agreement with the relevant Aboriginal group, there is an arbitration provision in the NTA.

There is also federal and state legislation to prevent damage to Aboriginal cultural heritage and archeological sites. The NTA and laws protecting Aboriginal cultural heritage and archeological sites have had no impact on our current operations.

Environmental

The federal system requires that approval is obtained for any activity which will have a significant impact on a matter of national environmental significance. Matters of national environmental significance include listed endangered species, nuclear actions, World Heritage areas, National Heritage areas, and migratory species. An application for such an approval may require public consultation and may be approved, refused or granted subject to conditions. Otherwise, responsibility for environmental regulation in Australia is primarily vested in the states.

Each state and territory in Australia has its own environmental and planning regime for the development of mines. In addition, each state and territory also has a specific act dealing with mining in particular, regulating the granting of mining licenses and leases. The mining legislation in each state and territory operates concurrently with environmental and planning legislation. The mining legislation governs mining licenses and leases, including the restoration of land following the completion of mining activities. Apart from the grant of rights to mine (which are covered by the mining statutes), all licensing, permitting, consent and approval requirements are contained in the various state and territory environmental and planning statutes.

The particular provisions of the various state and territory environmental and planning statutes vary depending upon the jurisdiction. Despite variation in details, each state and territory has a system involving at least two major phases. First, obtaining the developmental application and, if that is granted, obtaining the detailed operational pollution control licenses, which authorize emissions up to a maximum level; and second, obtaining pollution control approvals, which authorize the installation of pollution control equipment and devices. In the first regulatory phase, an application to a regulatory authority is filed. The relevant authority will either grant a conditional consent, an unconditional consent, or deny the application based on the details of the application and on any submissions or objections lodged by members of the public. If the developmental application is granted, the detailed pollution control license may then be issued and such license may regulate emissions to the atmosphere; emissions in waters; noise impacts, including impacts from blasting; dust impacts; the generation, handling, storage and transportation of waste; and requirements for the rehabilitation and restoration of land.

Each state and territory in Australia also has either a specific statute or certain sections in other environmental and planning statutes relating to the contamination of land and vesting powers in the various regulatory authorities in respect of the remediation of contaminated land. Those statutes are based on varying policies the primary difference between the statutes is that in certain states and territories, liability for remediation is placed upon the occupier of the land, regardless of the culpability of that occupier for the contamination. In other states and territories, primary liability for remediation is placed on the original polluter, whether or not the polluter still occupies the land. If the original polluter cannot itself carry out the remediation, then a number of the statutes contain provisions which enable recovery of the costs of remediation from the polluter as a debt.

Many of the environmental planning statutes across the states and territories contain third-party appeal rights in relation, particularly, to the first regulatory phase. This means that any party has a right to take proceedings for a threatened or actual breach of the statute, without first having to establish that any particular interest of that person (other than as a member of the public) stands to be affected by the threatened or actual breach.

Accordingly, in most states and territories throughout Australia, mining activities involve a number of regulatory phases. Following exploratory investigations pursuant to a mining lease, the activity proposed to be carried out must be the subject of an application for the activity or development. This phase of the regulatory process, as noted above, usually involves the preparation of extensive documents to constitute the application, addressing all of the environmental impacts of the proposed activity. It also generally involves extensive notification and consultation with other relevant statutory authorities and members of the public. Once a decision is made to allow a mine to be developed by the grant of a development consent, permit or other approval, then a formal mining lease can be

obtained under the mining statute. In addition, operational licenses and approvals can then be applied for and obtained in relation to pollution control devices and emissions to the atmosphere, to waters and for noise. The obtaining of licenses and approvals, during the operational phase,

generally does not involve any extensive notification or consultation with members of the public, as most of these issues are anticipated to be resolved in the first regulatory phase.

Occupational Health and Safety

The combined effect of various state and federal statutes requires an employer to ensure that persons employed in a mine are safe from injury by providing a safe working environment and systems of work; safety machinery; equipment, plant and substances; and appropriate information, instruction, training and supervision.

In recognition of the specialized nature of mining and mining activities, specific occupational health and safety obligations have been mandated under state legislation that deals specifically with the coal mining industry. Mining employers, owners, directors and managers, persons in control of work places, mine managers, supervisors and employees are all subject to these duties.

It is mandatory for an employer to have insurance coverage with respect to the compensation of injured workers; similar coverage is in effect throughout Australia which is of a no fault nature and which provides for benefits up to a prescribed level. The specific benefits vary from jurisdiction to jurisdiction, but generally include the payment of weekly compensation to an incapacitated employee, together with payment of medical, hospital and related expenses. The injured employee has a right to sue his or her employer for further damages if a case of negligence can be established.

National Greenhouse and Energy Reporting Act 2007 (NGER Act)

The NGER Act introduces a single national reporting system relating to greenhouse gas emissions and energy production and consumption, which will underpin a future emissions trading scheme.

The NGER Act imposes requirements for certain corporations to report greenhouse gas emissions and abatement actions, as well as energy production and consumption, beginning July 1, 2008. Both foreign and local corporations that meet the prescribed CO_2 and energy production of consumption limits in Australia (controlling corporations) must comply with the NGER Act.

In the first reporting year, 2008-09, a controlling corporation must register in the National Greenhouse and Energy Register if its corporate group emits a carbon dioxide equivalent of 125 kilotonnes or more. This threshold is reduced progressively in the following reporting years. Once registered, a corporation must report each financial year about its greenhouse gas emissions and energy production and consumption.

Kyoto Protocol

The Federal Labor Government, which came to power in November 2007, ratified the Kyoto Protocol on December 3, 2007, with the ratification to come into force in March 2008. Under the treaty, Australia has a target of restricting greenhouse gas emissions to 108% of 1990 levels during the 2008-2012 commitment period. It is likely that Australia will not meet its target (current projected Australian emissions in 2010 will be 109% of 1990 levels). This may result in legislated restrictions on CO_2 emissions before 2010, which could affect our Australian customers.

Ratification of the treaty will also allow Australian companies to begin participating in the Kyoto Protocol trading system (CDMs etc). Other Labor Government policies include committing to a target of reducing greenhouse gas emissions by 60% by 2050, and setting a 20% renewable energy target by 2020.

Future Cap and Trade System

The Federal Labor Government has announced that it will establish a cap and trade emissions trading scheme by 2010. Under such a system, total emissions will be capped, permits allocated up to the cap, and trading will allow the market to find the cheapest way to meet the cap. The Australian Securities Exchange has announced that it will facilitate emissions trading in a futures market for carbon emission permits at the earliest opportunity.

Global Climate Change

Global climate change continues to attract considerable public and scientific attention. Widely publicized scientific reports in 2007, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. In turn, considerable and increasing government attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants.

Legislation was introduced in Congress in 2006 and 2007 to reduce greenhouse gas emissions in the United States, and additional legislation is likely to be introduced in the future. Presently there are no federal mandatory greenhouse gas reduction requirements. While it is possible that Congress will adopt some form of mandatory greenhouse gas emission reduction legislation in the future, the timing and specific requirements of any such legislation are highly uncertain.

The U.S. Supreme Court s recent decision in Massachusetts v. EPA ruled that the EPA improperly declined to address carbon dioxide impacts on climate change in a recent rulemaking. Although the specific rulemaking related to new motor vehicles, the reasoning of the decision could affect other federal regulatory programs, including those that directly relate to coal use.

A number of states in the United States have taken steps to regulate greenhouse gas emissions. For example, 10 northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont) have formed the Regional Greenhouse Gas Initiative (RGGI), which is a mandatory cap-and-trade program to reduce carbon dioxide emissions from power plants. Seven western states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and two Canadian provinces have entered into the Western Climate Initiative to establish a regional greenhouse gas reduction goal and develop market-based strategies to achieve emissions reductions. In 2006, the California legislature approved legislation allowing the imposition of statewide caps on, and cuts in, carbon dioxide emissions; and Arizona s governor signed an executive order in September 2006 that calls for the state to reduce carbon dioxide emissions. Similar legislation was adopted in 2007 in Hawaii and New Jersey.

In December 1997, in Kyoto, Japan, the signatories to the 1992 Framework Convention on Climate Change, which addresses emissions of greenhouse gases, established a binding set of emission targets for developed nations. The United States has signed the Kyoto Protocol, but it has not been ratified by the U.S. Senate and the Bush Administration has withdrawn support for this treaty. As noted previously, Australia ratified the Kyoto Protocol in December 2007 and will become a full member in March 2008.

We continue to support clean coal technology development and voluntary initiatives addressing global climate change through our participation as a founding member of the FutureGen Alliance and through our participation in the Power Systems Development Facility, the PowerTree Carbon Company LLC, and the Asia-Pacific Partnership for Clean Development and Climate. In addition, we are the only non-Chinese equity partner in GreenGen, the first near-zero emissions coal-fueled power plant with carbon capture and storage (CCS) which is under development in China.

Enactment of laws and passage of regulations regarding greenhouse gas emissions by the United States or some of its states or by other countries, or other actions to limit carbon dioxide emissions, could result in electric generators switching from coal to other fuel sources.

Additional Information

We file annual, quarterly and current reports, and our amendments to those reports, proxy statements and other information with the Securities and Exchange Commission (SEC). You may access and read our SEC filings free of charge through our website, at www.peabodyenergy.com, or the SEC s website, at www.sec.gov. Information on such websites does not constitute part of this document. You may also read and copy any document we file at the SEC s public reference room located at 100 F Street, N.E., 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, free of charge, by telephone at (314) 342-3400 or by mail at: Peabody Energy Corporation, 701 Market Street, Suite 900, St. Louis, Missouri 63101, attention: Investor Relations.

Item 1A. ***Risk Factors.***

The risk factors discussed herein relate specifically to the risks associated with our continuing operations.

We may not be able to achieve some or all of the strategic objectives that we expected to achieve in connection with the spin-off of Patriot Coal Corporation in October 2007.

We may not be able to completely achieve the financial and strategic objectives of our spin-off of Patriot Coal Corporation or such objectives may be delayed in their realization if they ever occur.

If a substantial portion of our long-term coal supply agreements terminate, our revenues and operating profits could suffer if we are unable to find alternate buyers willing to purchase our coal on comparable terms to those in our contracts.

Most of our sales are made under coal supply agreements, which are important to the stability and profitability of our operations. The execution of a satisfactory coal supply agreement is frequently the basis on which we undertake the development of coal reserves required to be supplied under the contract. For the year ended December 31, 2007, 94% of our sales volume was sold under long-term coal supply agreements. At December 31, 2007, our sales backlog, including backlog subject to price reopener and/or extension provisions, was nearly one billion tons, representing more than four years of current production in backlog. Contracts in backlog have remaining terms ranging from one to 17 years.

Many of our coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. We may adjust these contract prices based on inflation or deflation and/or changes in the factors affecting the cost of producing coal, such as taxes, fees, royalties and changes in the laws regulating the mining, production, sale or use of coal. In a limited number of contracts, failure of the parties to agree on a price under those provisions may allow either party to terminate the contract. We sometimes experience a reduction in coal prices in new long-term coal supply agreements replacing some of our expiring contracts. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or the customer during the duration of specified events beyond the control of the affected party. Most coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as Btu, sulfur content, ash content, grindability and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or termination of the contracts. Moreover, some of these agreements permit the customer to terminate the contract if transportation costs, which our customers typically bear, increase substantially. In addition, some of these contracts allow our customers to terminate their contracts in the event of changes in regulations affecting our industry that increase the price of coal beyond specified limits.

The operating profits we realize from coal sold under supply agreements depend on a variety of factors. In addition, price adjustment and other provisions may increase our exposure to short-term coal price volatility provided by those contracts. If a substantial portion of our coal supply agreements were modified or terminated, we could be materially adversely affected to the extent that we are unable to find alternate buyers for our coal at the same level of profitability. Market prices for coal vary by mining region and country. As a result, we cannot predict the future strength of the coal market overall or by mining region and cannot assure you that we will be able to replace existing long-term coal supply agreements at the same prices or with similar profit margins when they expire. In addition, one of our largest coal supply agreements is the subject of ongoing litigation and arbitration.

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

For the year ended December 31, 2007, we derived 23% of our total coal revenues from sales to our five largest customers. At December 31, 2007, we had 125 coal supply agreements and trading transactions with these customers expiring at various times from 2008 to 2014. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and those customers may not continue to purchase coal from us under long-term coal supply agreements. If a number of these customers significantly reduce their purchases of coal from us, or if we are 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.

If transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal could suffer.

Transportation costs represent a significant portion of the total cost of coal and the cost of transportation is a critical factor in a customer s purchasing decision. Increases in transportation costs and the lack of sufficient rail and port capacity could lead to reduced coal sales. As of December 31, 2007, certain coal supply agreements, which account for less than 5% of our tons sold, permit the customer to terminate the contract if the cost of transportation increases by an amount over specified levels in any given 12-month period.

Coal producers depend upon rail, barge, trucking, overland conveyor and ocean-going vessels to deliver coal to markets. While our coal customers typically arrange and pay for transportation of coal from the mine or port to the point of use, disruption of these transportation services because of weather-related problems, infrastructure damage, strikes, lock-outs, lack of fuel or maintenance items, transportation delays or other events could temporarily impair our ability to supply coal to our customers and thus could adversely affect our results of operations. For example, two primary railroads serve the Powder River Basin mines. Due to the high volume of coal shipped from all Powder River Basin mines, the loss of access to rail capacity could create temporary congestion on the rail systems servicing that region. In Australia we currently ship coal through the ports of Dalrymple Bay, Gladstone, Brisbane, Newcastle and Port Kembla. In most instances, we rail coal to these ports. The Australian coal supply chains (rail and port) can be impacted by a number of factors including weather events, breakdown or underperformance of the port and rail infrastructure, congestion and balancing systems which are imposed to manage vessel queuing and demurrage. We are also susceptible to increased costs or lost sales due to Australian coal chain problems. In 2007, we experienced high demurrage costs (fees paid to third-party shipping companies for loading time that exceeded the stipulated time) and increased vessel wait times due to these problems and the high demand for Australian coal.

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.

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

Global climate change continues to attract considerable public and scientific attention. Widely publicized scientific reports in 2007, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate

Change, have also engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. In turn, considerable and increasing government attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants. Legislation was introduced in Congress in 2006 and 2007 to reduce greenhouse gas emissions in the United States and additional legislation is likely to be introduced in the future. In addition, a growing number of states in the United States are taking steps to reduce greenhouse gas emissions from coal-fired power plants. The U.S. Supreme Court s recent decision in Massachusetts v. EPA ruled that the EPA improperly declined to address carbon dioxide impacts on climate change in a recent rulemaking. Although the specific rulemaking related to new motor vehicles, the reasoning of the decision could affect other federal regulatory programs, including those that directly relate to coal use. Enactment of laws and passage of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions, could result in electric generators switching from coal to other fuel sources.

Concerns about other adverse environmental effects from coal combustion have also led to increased regulation. For example, in the United States, CAIR and CAMR, both issued by the EPA in March 2005, impose increasingly stringent requirements on coal-fired power plants in order to reduce emissions of sulfur dioxide, nitrogen oxide, and mercury. Each of the regulations takes effect in two phases, the first phase requiring certain reductions in overall emissions by 2009-10, the second requiring additional reductions in overall emissions by 2015 under CAIR and 2018 under CAMR. Both rules have been the subject of legal challenges by environmental advocacy groups that seek larger cuts sooner. On February 2, 2008, the Court of Appeals for the District of Columbia rendered a decision effectively vacating CAMR. If the decision stands, the EPA will have to revisit its standards regarding mercury emissions. Some states have independently established requirements imposing larger cuts sooner. Such requirements, in varying degrees, increase the costs of coal utilization for our customers and our prospective customers.

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

Our mining operations are extensively regulated, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal.

Federal, state and local authorities regulate the coal mining industry with respect to matters such as employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Numerous governmental permits and approvals are required for mining operations. We are required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment. The costs, liabilities and requirements associated with these regulations may be costly and time-consuming and may delay commencement or continuation of exploration or production. The possibility exists that new legislation and/or regulations and orders related to the environment or employee health and safety may be adopted and may materially adversely affect our mining operations, our cost structure and/or our customers ability to use coal. New legislation or administrative regulations (or judicial interpretations 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. Some 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. These factors and legislation, if enacted, could have a material adverse effect on our financial condition and results of operations.

A number of laws, including in the U.S. the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund), impose liability relating to contamination by hazardous substances. Such liability may involve the costs of investigating or remediating contamination and damages to natural resources, as well as claims seeking to recover for property damage or personal injury caused by hazardous substances. Such liability may arise from conditions at formerly as well as currently owned or operated properties, and at properties to which hazardous substances have been sent for treatment, disposal, or other handling. Liability under CERCLA and similar state statutes is without regard to fault, and typically is joint and several, meaning that a person may be held responsible for more than its share, or even all of, the liability involved. Our mining operations involve some use of hazardous materials. In addition, we have accrued for liability arising out of contamination associated with Gold Fields Mining, LLC (Gold Fields), a dormant, non-coal-producing subsidiary of ours that was previously managed and owned by Hanson PLC, or with Gold Fields former affiliates. A predecessor owner of ours, Hanson PLC transferred ownership of Gold Fields to us in the February 1997 spin-off of its energy business. Gold Fields is currently a defendant in several lawsuits and has received notices of several other potential claims arising out of lead contamination from mining and milling operations it conducted in northeastern Oklahoma. Gold Fields is also involved in investigating or remediating a number of other contaminated sites. Although we have accrued for many of these liabilities known to us, the amounts of other potential losses cannot be estimated. Significant uncertainty exists as to whether claims will be pursued against Gold Fields in all cases, and where they are pursued, the amount of the eventual costs and liabilities, which could be greater or less than our accrual. Although we believe many of these liabilities are likely to be resolved without a material adverse effect on us, future developments, such as new information concerning areas known to be or suspected of being contaminated for which we may be responsible, the discovery of new contamination for which we may be responsible, or the inability to share costs with other parties that may be responsible for the contamination, could have a material adverse effect on our financial condition or results of operations.

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

We provide postretirement health and life insurance benefits to eligible union and non-union employees. We calculated the total accumulated postretirement benefit obligation under SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions, which we estimate had a present value of $855.8 million as of December 31, 2007, $70.1 million of which was a current liability. We have estimated these unfunded obligations based on assumptions described in the notes to our consolidated financial statements. If our assumptions do not materialize as expected, cash expenditures and costs that we incur could be materially higher. Moreover, regulatory changes or changes to Medicare benefit levels could increase our obligations to provide these or additional benefits.

We are party to an agreement with the PBGC and TXU Europe Limited, an affiliate of our former parent corporation, under which we are required to make specified contributions to two of our defined benefit pension plans and to maintain a $37.0 million letter of credit in favor of the PBGC. If we or the PBGC give notice of an intent to terminate one or more of the covered pension plans in which liabilities are not fully funded, or if we fail to maintain the letter of credit, the PBGC may draw down on the letter of credit and use the proceeds to satisfy liabilities under the Employment Retirement Income Security Act of 1974, as amended. The PBGC, however, is required to first apply amounts received from a $110.0 million guaranty in place from TXU Europe Limited in favor of the PBGC before it draws on our letter of credit. On November 19, 2002, TXU Europe Limited was placed under the administration process in the United Kingdom (a process similar to bankruptcy proceedings in the United States) and continues under this process as of December 31, 2007.

The United Mine Workers of America Combined Fund was created by federal law in 1992. This multi-employer fund provides health care benefits to a closed group of retirees including retired employees of our former subsidiaries (now owned by Patriot Coal Corporation) who last worked prior to 1976, as well as orphaned beneficiaries of bankrupt

companies who were receiving benefits as orphans prior to the 1992 law.

No new retirees will be added to this group. The liability is subject to increases or decreases in per capita health care costs, offset by the mortality curve in this aging population of beneficiaries. Another fund, the 1992 Benefit Plan created by the same federal law in 1992, provides benefits to qualifying retired former employees of bankrupt companies who have defaulted in providing their former employees with retiree medical benefits. Beneficiaries continue to be added to this fund as employers default in providing their former employees with retiree medical benefits, but the overall exposure for new beneficiaries into this fund is limited to retirees covered under their employer s plan who retired prior to October 1, 1994. A third fund, the 1993 Benefit Plan, was established through collective bargaining and provides benefits to qualifying retired former employees who retired after September 30, 1994 of certain signatory companies who have gone out of business and have defaulted in providing their former employees with retiree medical benefits. Beneficiaries continue to be added to this fund as employers go out of business.

The Surface Mining Control and Reclamation Act Amendments of 2006 (the 2006 Act) authorizes a specified amount of federal funds to pay for these programs on a phased-in basis and other programs. To the extent that (i) the annual retiree health care funding requirement exceeds the specified amount of federal funds, (ii) Congress does not allocate additional funds to cover the shortfall, and (iii) Patriot s subsidiaries do not pay for their share of the shortfall, some of our subsidiaries would be responsible for the additional costs.

A decrease in the availability or increase in costs of key supplies, capital equipment or commodities such as diesel fuel, steel, explosives and tires could decrease our anticipated profitability.

Our mining operations require a reliable supply of replacement parts, explosives, fuel, tires, steel-related products (including roof control) and lubricants. If the cost of any of these inputs increased significantly, or if a source for these supplies or mining equipment were unavailable to meet our replacement demands, our profitability could be reduced from our current expectations. Recent consolidation of suppliers of explosives has limited the number of sources for these materials, and our current supply of explosives is concentrated with one supplier. Further, our purchases of some items of underground mining equipment are concentrated with one principal supplier. Over the past few years, industry-wide demand growth has exceeded supply growth for certain surface and underground mining equipment and other capital equipment as well as off-the-road tires. As a result, lead times for some items have increased significantly.

Our future success depends upon our ability to continue acquiring and developing coal reserves that are economically recoverable.

Our recoverable reserves decline as we produce coal. We have not yet applied for the permits required or developed the mines necessary to use all of our reserves. Furthermore, we may not be able to mine all of our reserves as profitably as we do at our current operations. Our future success depends upon our conducting successful exploration and development activities or acquiring properties containing economically recoverable reserves. Our current strategy includes increasing our reserves through acquisitions of government and other leases and producing properties and continuing to use our existing properties. The federal government also leases natural gas and coalbed methane reserves in the West, including in the Powder River Basin. Some of these natural gas and coalbed methane reserves are located on, or adjacent to, some of our Powder River Basin reserves, potentially creating conflicting interests between us and lessees of those interests. Other lessees rights relating to these mineral interests could prevent, delay or increase the cost of developing our coal reserves. These lessees may also seek damages from us based on claims that our coal mining operations impair their interests. Additionally, the federal government limits the amount of federal land that may be leased by any company to 150,000 acres nationwide. As of December 31, 2007, we leased a total of 63,463 acres from the federal government. The limit could restrict our ability to lease additional federal lands. For additional discussion of our federal leases see Item 2. Properties.

Our planned mine development projects and acquisition activities may not result in significant additional reserves, and we may not have continuing success developing additional mines. Most of our mining operations are conducted on properties owned or leased by us. Because title to most of our leased properties and mineral rights are not thoroughly verified until a permit to mine the property is obtained, our right to mine some of our reserves may be materially adversely affected if defects in title or boundaries exist. In addition, in order to

develop our reserves, we must receive various governmental permits. We cannot predict whether we will continue to receive the permits necessary for us to operate profitably in the future. We may not be able to negotiate new leases from the government or from private parties, obtain mining contracts for properties containing additional reserves or maintain our leasehold interest in properties on which mining operations are not commenced during the term of the lease. From time to time, we have experienced litigation with lessors of our coal properties and with royalty holders.

A decrease in our production of metallurgical coal could decrease our anticipated profitability.

We have annual capacity to produce approximately 8 to 10 million tons of metallurgical coal. Prices for metallurgical coal at the end of 2007 were near historically high levels. As a result, our margins from these sales have increased significantly, and represented a larger percentage of our overall revenues and profits and are expected to continue to favorably contribute in the future. To the extent we experience either production or transportation difficulties that impair our ability to ship metallurgical coal to our customers at anticipated levels, our profitability could be reduced in 2008.

The majority of our 2008 metallurgical coal production will be priced during the first quarter of 2008. As a result, a decrease in logistics or port capacity could decrease our profitability.

Our financial performance could be adversely affected by our debt.

Our financial performance could be affected by our indebtedness. As of December 31, 2007, our total indebtedness was $3.27 billion, and we had $1.29 billion of available borrowing capacity under our Revolving Credit Facility. The indentures governing our convertible debentures and 7.375% and 7.875% Senior Notes do not limit the amount of indebtedness that we may issue, and the indentures governing our 6.875% and 5.875% Senior Notes permit the incurrence of additional indebtedness.

The degree to which we are leveraged could have important consequences, including, but not limited to:

- making it more difficult for us to pay interest and satisfy our debt obligations;
- increasing our vulnerability to general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of our cash flow from operations to the payment of principal, and interest on, our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, acquisitions, research and development or other general corporate uses;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions, research and development or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal industry; and
- placing us at a competitive disadvantage compared to less leveraged competitors.

In addition, our indebtedness subjects us to financial and other restrictive covenants. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have a material adverse effect on us.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not

be successful and may not permit us to meet our scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. The Senior Unsecured Credit Facility and indentures governing certain of our notes restrict our ability to sell assets and use the proceeds from the sales. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

The covenants in our senior unsecured credit facility and the indentures governing our senior notes and convertible debentures impose restrictions that may limit our operating and financial flexibility.

Our Senior Unsecured Credit Facility, the indentures governing our senior notes and convertible debentures and the instruments governing our other indebtedness contain certain restrictions and covenants which restrict our ability to incur liens and debt or provide guarantees in respect of obligations of any other person. Under our Senior Unsecured Credit Facility, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio, as defined. The financial covenants also place limitations on our investments in joint ventures, unrestricted subsidiaries, indebtedness of non-loan parties and the imposition of liens on our assets. These covenants and restrictions are reasonable and customary and have not impacted our business in the past.

Operating results below current levels or other adverse factors, including a significant increase in interest rates, could result in our inability to comply with the financial covenants contained in our Senior Unsecured Credit Facility. If we violate these covenants and are unable to obtain waivers from our lenders, our debt under these agreements would be in default and could be accelerated by our lenders. If our indebtedness is accelerated, we may not be able to repay our debt or borrow sufficient funds to refinance it. Even if we are able to obtain new financing, it may not be on commercially reasonable terms, 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. In addition, complying with these covenants may also cause us to take actions that are not favorable to holders of our other debt or equity securities and may make it more difficult for us to successfully execute our business strategy and compete against companies who are not subject to such restrictions.

Our operations could be adversely affected if we fail to appropriately secure our obligations.

U.S. federal and state laws and Australian laws require us to secure certain of our obligations to reclaim lands used for mining, to pay federal and state workers compensation, to secure coal lease obligations and to satisfy other miscellaneous obligations. The primary method for us to meet those obligations is to post a corporate guarantee (i.e. self bond), provide a third-party surety bond or provide a letter of credit. As of December 31, 2007, we had $640.6 million of self bonds in place primarily for our reclamation obligations. As of December 31, 2007, we also had outstanding surety bonds with third parties and letters of credit of $952.9 million, of which $419.9 million was for post-mining reclamation, $133.9 million related to workers compensation obligations, $41.4 million was for retiree healthcare obligations, $73.0 million was for coal lease obligations, and $284.7 million was for other obligations, including collateral for surety companies and bank guarantees, road maintenance, and performance guarantees. As of December 31, 2007, the amount of letters of credit securing Patriot obligations was $136.8 million, of which $95.4 million related to Patriot s workers compensation obligations. Surety bonds are typically renewable on a yearly basis. Surety bond issuers and holders may not continue to renew the bonds or may demand additional collateral upon those renewals. Letters of credit are subject to our successful renewal of our bank revolving credit facilities, which are currently set to expire in 2011. Our failure to maintain, or inability to acquire, surety bonds or letters of credit or to provide a suitable alternative would have a material adverse effect on us. That failure could result from a variety of factors including the following:

- lack of availability, higher expense or unfavorable market terms of new surety bonds;
- restrictions on the availability of collateral for current and future third-party surety bond issuers under the terms of our indentures or Senior Unsecured Credit Facility;
- the exercise by third-party surety bond issuers of their right to refuse to renew the surety; and

inability to renew our credit facility.

Our ability to self bond reduces our costs of providing financial assurances. To the extent we are unable to maintain our current level of self bonding, due to legislative or regulatory changes or changes in our financial condition, our costs would increase.

The conversion of our convertible debentures may result in the dilution of the ownership interests of our existing stockholders.

If the conditions permitting the conversion of our convertible debentures are met and holders of the convertible debentures exercise their conversion rights, any conversion value in excess of the principal amount will be delivered in shares of our common stock. If any common stock is issued in connection with a conversion of our convertible debentures, our existing stockholders will experience dilution in the voting power of their common stock and earnings per share could be negatively impacted.

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

Certain provisions of our convertible debentures could make it more difficult or more expensive for a third-party to acquire us. Upon the occurrence of certain transactions constituting a change of control as defined in the indenture relating to our convertible debentures, holders of our convertible debentures will have the right, at their option, to convert their convertible debentures and thereby require us to pay the principal amount of such converted debentures in cash.

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

In conducting our trading, brokerage and mining operations, we utilize third-party sources of coal production, including contract miners and brokerage sources, to fulfill deliveries under our coal supply agreements. In Australia, the majority of our mines utilize contract miners. Employee relations at mines that use contract miners is the responsibility of the contractor.

Our profitability or exposure to loss on transactions or relationships is dependent upon the reliability (including financial viability) and price of the third-party suppliers, 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. The recent market volatility and price increases for coal on the international markets could result in non-performance by third-party suppliers under existing contracts with us, in order to take advantage of the higher prices in the current market. Such non-performance could have an adverse impact on our ability to fulfill deliveries under our coal supply agreements.

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. Coal prices in most regions of the U.S. and globally were approaching record highs in early 2008, and the sustainability of these prices or its effects on future production is uncertain.

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

As of December 31, 2007, we had approximately 7,000 employees. As of such date, approximately 27% of our hourly employees were represented by unions and they generated approximately 10% of our 2007 coal production. Relations with our employees and, where applicable, organized labor are important to our success.

Due to the higher labor costs and the increased risk of strikes and other work-related stoppages that may be associated with union operations in the coal industry, our competitors who operate without union labor may have a competitive advantage in areas where they compete with our unionized operations. If some or all of our current non-union operations were to become unionized, we could incur an increased risk of work stoppages, reduced productivity and higher labor costs.

United States Labor Relations

Approximately 85% of our U.S. miners are non-union and are employed in the states of Wyoming, Colorado, Indiana, New Mexico, and Illinois. The UMWA under the Western Surface Agreement represented approximately 6% of our U.S. subsidiaries hourly employees, who generated 4% of our U.S. production during the year ended December 31, 2007. An additional 7% of our U.S. subsidiaries hourly employees are represented by labor unions other than the UMWA. These employees generated 2% of our U.S. production during the year ended December 31, 2007. Hourly workers at our mine in Arizona are represented by the UMWA under the Western Surface Agreement, which is effective through September 2, 2013. In April 2007, a new labor agreement was ratified for our hourly workforce at the Willow Lake Mine, which is represented by the International Brotherhood of Boilermakers. The new four-year labor agreement expires on April 15, 2011.

Australia Labor Relations

The Australian coal mining industry is unionized and all of our hourly workers and those employed through our contract mining relationships are members of trade unions. The Construction Forestry Mining and Energy Union represents our Australian subsidiary s hourly production employees. As of December 31, 2007, our Australian hourly employees were approximately 26% of our Australian hourly workforce and generated 29% of our Australian total production in the year then ended. The labor agreements at our Metropolitan Mine were renewed in July and October 2007 and those agreements expire in 2010. The Wambo mine coal handling plant labor agreement is under negotiation and the North Goonyella Mine operates under an agreement due to expire in March 2008.

Our ability to operate our company effectively could be impaired if we lose key personnel or fail to attract qualified personnel.

We manage our business with a number of key personnel, the loss of a number of whom could have a material adverse effect on us. 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 and qualified personnel. We cannot assure you that key personnel will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have a material adverse effect on us.

Due to the current demographics of our mining workforce, a high portion of our current hourly employees are eligible to retire over the next decade. Additionally, many of our mine sites are in more secluded areas of the United States, such as the Native American reservations of Arizona and the Southern Powder River Basin of Wyoming. These geographic locations provide limited pools of qualified personnel, and it is challenging to locate qualified persons interested in working in some of these regions. Failure to attract new employees to the mining workforce could have a material adverse effect on us.

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 has changed with deregulation as utilities have sold their power plants to their non-regulated affiliates or third parties. These new power plant owners or other customers may have credit ratings that are below investment grade. If deterioration of the creditworthiness of our customers occurs, our $275.0 million accounts receivable securitization program and our business could be adversely affected.

Our certificate of incorporation and by-laws include provisions that may discourage a takeover attempt.

Provisions contained in our certificate of incorporation and by-laws and Delaware law could make it more difficult for a third-party to acquire us, even if doing so might be beneficial to our stockholders. Provisions of our by-laws and certificate of incorporation impose various procedural and other requirements that could make it more difficult for stockholders to effect certain corporate actions. For example, a change in control of our Company may be delayed or deterred as a result of the stockholders rights plan adopted by our Board of

Directors. These provisions could limit the price that certain investors might be willing to pay in the future for shares of our common stock and may have the effect of delaying or preventing a change in control.

Growth in our global operations increases our risks unique to international mining and trading operations.

We currently have international mining operations in Australia and Venezuela. We have a business development, sales and marketing office in Beijing, China and an international trading group in our Trading and Brokerage operations. In addition, we are actively pursuing long-term operating, trading and joint-venture opportunities in China, Mongolia and Mozambique. The international expansion of our operations increases our exposure to country and currency risks. Some of our international activities include expansion into developing countries where business practices and counterparty reputations may not be as well developed as in our U.S. or Australian operations. We are also challenged by political risks, including expropriation and the inability to repatriate earnings on our investment. In particular, the Venezuelan government has suggested its desire to increase government ownership in Venezuelan energy assets and natural resources. Actions to nationalize Venezuelan coal properties could be detrimental to our investments in the Paso Diablo Mine and Cosila development project. During 2007, the Paso Diablo Mine contributed $21.2 million to segment Adjusted EBITDA in Corporate and Other Adjusted EBITDA (see Item 7) and paid a dividend of $12.9 million. At December 31, 2007, our investment in Paso Diablo was $68.4 million, recorded in Investments and other assets on the consolidated balance sheet.

As we continue to pursue development of Generation Development and Btu Conversion activities, we face challenges and risks that differ from those in our mining business.

We continue to pursue the development of coal-fueled generating projects in the U.S., including mine-mouth generating plants using our surface lands and coal reserves. Our ultimate role in these projects could take numerous forms, including, but not limited to, equity partner, contract miner or coal sales. We are a 5.06% owner in the 1,600 plus-megawatt Prairie State Energy Campus in Washington County, Illinois and are pursuing development of the 1,500-megawatt Thoroughbred Energy Campus in Muhlenberg County, Kentucky. We also continue to pursue opportunities to participate in technologies to economically convert our coal resources to natural gas and liquids such as diesel fuel, gasoline and jet fuel (Btu Conversion).

As we move forward with all of these projects, we are exposed to risks related to the performance of our partners, securing required financing, obtaining necessary permits, meeting stringent regulatory laws, maintaining strong supplier relationships and managing (along with our partners) large projects, including managing through long lead times for ordering and obtaining capital equipment. Our work in new or recently commercialized technologies could expose us to unanticipated risks, evolving legislation and uncertainty regarding the extent of future government support and funding.

The implementation of our new enterprise resource planning system carries certain risks, including the potential for business interruption, and the associated adverse impact.

To support the continued growth and globalization of our businesses, we are converting our existing information systems across major business processes to an integrated information technology system provided by SAP AG. The U.S. implementation occurred in August 2007. We made extensive plans to support effective implementation of this information technology system. Such a major undertaking carries the additional risk of unforeseen issues, interruptions and costs. The extent to which we successfully convert our information technology systems and address unforeseen issues will have a direct bearing on our ability to perform certain day-to-day functions.

Diversity in interpretation and application of accounting literature in the mining industry may impact our reported financial results.

The mining industry has limited industry-specific accounting literature and, as a result, we understand diversity in practice exists in the interpretation and application of accounting literature to mining specific

issues. For example, some companies capitalize drilling and related costs incurred to delineate and classify mineral resources as proven and probable reserves, and other companies expense such costs. In addition, some industry participants expense pre-production stripping costs associated with developing new pits at existing surface mining operations, while other companies capitalize pre-production stripping costs for new pit development at existing operations. The materiality of such expenditures can vary greatly relative to a given company s respective financial position and results of operations. As diversity in mining industry accounting is addressed, we may need to restate our reported results if the resulting interpretations differ from our current accounting practices (for additional information regarding our accounting policies with respect to drilling costs and advance stripping costs, please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates).

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

None.

Item 2. ***Properties.***

Coal Reserves

We had an estimated 9.3 billion tons of proven and probable coal reserves as of December 31, 2007. An estimated 8.2 billion tons of our proven and probable coal reserves are in the United States and 1.1 billion tons are in Australia. Forty-six percent of our reserves, or 4.2 billion tons, are compliance coal and 54% are non-compliance coal. We own approximately 37% of these reserves and lease property containing the remaining 63%. Compliance coal is defined by Phase II of the Clean Air Act as coal having sulfur dioxide content of 1.2 pounds or less per million Btu. Electricity generators are able to use coal that exceeds these specifications by using emissions reduction technology, using emission allowance credits or blending higher sulfur coal with lower sulfur coal.

Below is a table summarizing the locations and reserves of our major operating regions.

Operating Regions	Locations	Proven and Probable Reserves as of December 31, 2007[1]		
		Owned Tons	Leased Tons	Total Tons
		(Tons in millions)		
Midwest	Illinois, Indiana and Kentucky	2,686	1,005	3,691
Powder River Basin	Wyoming and Montana	67	3,274	3,341
Southwest	Arizona and New Mexico	639	351	990
Colorado	Colorado	35	171	206
Total United States		3,427	4,801	8,228
Australia	New South Wales		484	484
Australia	Queensland		589	589
Total Australia			1,073	1,073
Total Proven and Probable Coal Reserves		3,427	5,874	9,301

(1) Reserves have been adjusted to take into account estimated losses involved in producing a saleable product.

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 and probable coal reserves are defined by SEC Industry Guide 7 as follows:

Proven (Measured) Reserves Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so close and

the geographic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

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

Our estimates of proven and probable coal reserves are established within these guidelines. Proven reserves require the coal to lie within one-quarter mile of a valid point of measure or point of observation, such as exploratory drill holes or previously mined areas. Estimates of probable reserves may lie more than one-quarter mile, but less than three-quarters of a mile, from a point of thickness measurement. Estimates within the proven category have the highest degree of assurance, while estimates within the probable category have only a moderate degree of geologic assurance. Further exploration is necessary to place probable reserves into the proven reserve category. Our active properties generally have a much higher degree of reliability because of increased drilling density. Active surface reserves generally have points of observation as close as 330 feet to 660 feet.

Our reserve estimates are prepared by our staff of geologists, whose experience ranges from 10 to over 30 years. We also have a chief geologist of reserve reporting whose primary responsibility is to track changes in reserve estimates, supervise our other geologists and coordinate periodic third-party reviews of our reserve estimates by qualified mining consultants.

Our reserve estimates are predicated on information obtained from our ongoing drilling program, which totals nearly 500,000 individual drill holes. We compile data from individual drill holes in a computerized drill-hole database from which the depth, thickness and, where core drilling is used, the quality of the coal are determined. The density of the drill pattern determines whether the reserves will be classified as proven or probable. The reserve estimates are then input into our computerized land management system, which overlays the geological data with data on ownership or control of the mineral and surface interests to determine the extent of our reserves in a given area. The land management system contains reserve information, including the quantity and quality (where available) of reserves as well as production rates, surface ownership, lease payments and other information relating to our coal reserves and land holdings. We periodically update our reserve estimates to reflect production of coal from the reserves and new drilling or other data received. Accordingly, reserve estimates will change from time to time to reflect mining activities, analysis of new engineering and geological data, changes in reserve holdings, modification of mining methods and other factors.

Our estimate of the economic recoverability of our reserves is based upon a comparison of unassigned reserves to assigned reserves currently in production in the same geologic setting to determine an estimated mining cost. These estimated mining costs are compared to existing market prices for the quality of coal expected to be mined and taking into consideration typical contractual sales agreements for the region and product. Where possible, we also review production by competitors in similar mining areas. Only reserves expected to be mined economically are included in our reserve estimates. Finally, our reserve estimates include reductions for recoverability factors to estimate a saleable product.

We periodically engage independent mining and geological consultants and consider their input regarding the procedures used by us to prepare our internal estimates of coal reserves, selected property reserve estimates and tabulation of reserve groups according to standard classifications of reliability.

With respect to the accuracy of our reserve estimates, our experience is that recovered reserves are within plus or minus 10% of our proven and probable estimates, on average, and our probable estimates are generally within the same statistical degree of accuracy when the necessary drilling is completed to move reserves from the probable to the

proven classification.

We have numerous federal coal leases that are administered by the U.S. Department of the Interior under the Federal Coal Leasing Amendments Act of 1976. These leases cover our principal reserves in Wyoming

and other reserves in Montana and Colorado. Each of these leases continues indefinitely, provided there is diligent development of the property and continued operation of the related mine or mines. The Bureau of Land Management has asserted the right to adjust the terms and conditions of these leases, including rent and royalties, after the first 20 years of their term and at 10-year intervals thereafter. Annual rents on surface land under our federal coal leases are now set at $3.00 per acre. Production royalties on federal leases are set by statute at 12.5% of the gross proceeds of coal mined and sold for surface-mined coal and 8% for underground-mined coal. The federal government limits by statute the amount of federal land that may be leased by any company and its affiliates at any time to 75,000 acres in any one state and 150,000 acres nationwide. As of December 31, 2007, we leased 11,103 acres of federal land in Colorado, 11,254 acres in Montana and 41,106 acres in Wyoming, for a total of 63,463 nationwide.

Similar provisions govern three coal leases with the Navajo and Hopi Indian tribes. These leases cover coal contained in 65,000 acres of land in northern Arizona lying within the boundaries of the Navajo Nation and Hopi Indian reservations. We also lease coal-mining properties from various state governments.

Private U.S. coal leases normally have terms of between 10 and 20 years and usually give us the right to renew the lease for a stated period or to maintain the lease in force until the exhaustion of mineable and merchantable coal contained on the relevant site. These private U.S. leases provide for royalties to be paid to the lessor either as a fixed amount per ton or as a percentage of the sales price. Many U.S. leases also require payment of a lease bonus or minimum royalty, payable either at the time of execution of the lease or in periodic installments.

The terms of our private U.S. leases are normally extended by active production at or near the end of the lease term. U.S. leases containing undeveloped reserves may expire or these leases may be renewed periodically. With a portfolio of approximately 9.3 billion tons, we believe that we have sufficient reserves to replace capacity from depleting mines for the foreseeable future and that our significant reserve holdings is one of our strengths. We believe that the current level of production at our major mines is sustainable for the foreseeable future.

Mining and exploration in Australia is generally carried on under leases or licenses granted by state governments. Mining leases are typically for an initial term of up to 21 years (but which may be renewed) and contain conditions relating to such matters as minimum annual expenditures, restoration and rehabilitation. Royalties are paid to the State Government as a percentage of sale prices. Generally landowners do not own the mineral rights or have the ability to grant rights to mine those minerals. These rights are retained by State Governments. Compensation is payable to landowners for loss of access to the land, and the amount of compensation can be determined by agreement or arbitration. Surface rights are typically acquired directly from landowners and, in the absence of agreement, there is an arbitration provision in the mining law.

Consistent with industry practice, we conduct only limited investigation 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 properties are not completely verified until we prepare to mine those reserves.

The following chart provides a summary, by mining complex, of production for the years ended December 31, 2007 and 2006 and 2005, tonnage of coal reserves that is assigned to our operating mines, our property interest in those reserves and other characteristics of the facilities.

PRODUCTION AND ASSIGNED RESERVES[1]
(Tons in millions)

	Production				Sulfur Content[2]					As of December	
Mining Complex	Year Ended Dec. 31, 2007	Year Ended Dec. 31, 2006	Year Ended Dec. 31, 2005	Type of Coal	<1.2 lbs. sulfur dioxide per Million Btu	>1.2 to 2.5 lbs. sulfur dioxide per Million Btu	>2.5 lbs. sulfur dioxide per Million Btu	As Received Btu per pound[3]	Assigned Proven and Probable Reserves	Owned	Leased
	2.1	2.2	2.1	Steam	24	1	31	11,300	56	3	53
e	1.4	1.7	2.3	Steam		6	13	11,300	19		19
	1.6	1.6	1.0	Steam		2	25	10,000	27	26	1
	2.2	2.0	1.8	Steam			3	10,500	3		3
nd	0.9	1.1	1.2	Steam			33	11,200	33	4	29
	3.5	3.8	3.8	Steam	1	11	16	10,600	28	19	9
	3.4	3.5	3.4	Steam			2	10,400	2	1	1
	2.5	2.4	2.4	Steam			5	10,500	5	5	
	2.5	2.5	2.4	Steam			15	9,900	15	9	6
	1.7	1.5	1.5	Steam		1	8	10,600	9		9
	2.9	2.4	2.6	Steam			34	11,200	34	21	13
	2.7	2.6	0.5	Steam			18	11,000	18	18	
	3.6	3.6	3.7	Steam			44	11,300	44	32	12
	31.0	30.9	28.7		25	21	247		293	138	155
elle	91.5	88.6	82.7	Steam	1,097			8,800	1,097		1,097
	31.2	32.8	30.5	Steam	756	122	23	8,600	901		901
	17.2	17.0	12.4	Steam	274	59	53	8,600	386		386
	139.9	138.4	125.6		2,127	181	76		2,384		2,384
			3.9	Steam				NA			
	8.0	8.2	8.2	Steam	164	84	6	11,000	254		254
	5.3	5.5	5.3	Steam	21	121	12	10,000	154	92	62
	8.3	8.6	9.4	Steam	61			10,800	61	14	47
			1.1	Steam				NA			

	21.6	22.3	27.9		246	205	18		469	106	363
glefield	2.8	2.2	2.1	Met.	45			12,800	45		45
	1.5	0.4		Met.	39			12,700	39		39
	2.4	2.0	1.9	Steam	344			10,800	344		344
(5)	0.6	0.2		Steam	15			11,900	15		15
	4.4	1.2		Steam	121			12,400	121		121
	3.1	4.3	4.4	Steam/Met.	33			12,400	33		33
	0.4	0.2		Steam/Met.		2		12,200	2		2
	5.1	0.3		Steam		190		9,900	190		190
	1.3	0.1		Met.	23			12,800	23		23
	21.6	10.9	8.4		620	192			812		812
ons	17.0	23.3	22.4								
	231.1	225.8	213.0		3,018	599	341		3,958	244	3,714

The following chart provides a summary of the amount of our proven and probable coal reserves in each U.S. state and Australia state, the predominant type of coal mined in the applicable location, our property interest in the reserves and other characteristics of the facilities.

ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES
As of December 31, 2007
(Tons in millions)

Total Tons		Proven and Probable				Sulfur Content[2]				Reserve Control		M
Assigned	Unassigned	Reserves[6]	Proven	Probable	Type of Coal	<1.2 lbs. sulfur dioxide per Million Btu	>1.2 to 2.5 lbs. sulfur dioxide per Million Btu	>2.5 lbs. sulfur dioxide per Million Btu	As Received Btu per pound[3]	Owned	Leased	Su
116	2,210	2,326	1,154	1,172	Steam		24	2,302	10,500	1,821	505	
177	490	667	433	234	Steam	25	15	627	10,400	395	272	
	698	698	373	325	Steam		1	697	11,000	470	228	
293	3,398	3,691	1,960	1,731		25	40	3,626		2,686	1,005	
	162	162	158	4	Steam	15	117	30	8,600	67	95	
2,384	795	3,179	3,111	68	Steam	2,900	181	98	8,700		3,179	
2,384	957	3,341	3,269	72		2,915	298	128		67	3,274	
254	18	272	272		Steam	181	86	5	10,900		272	
60	146	206	140	66	Steam	151		55	10,700	35	171	
155	563	718	650	68	Steam	90	361	267	9,200	639	79	
469	727	1,196	1,062	134		422	447	327		674	522	
365	119	484	309	175	Steam/Met.	294	190		12,400		484	
447	142	589	110	479	Steam/Met.	587	2		11,200		589	
812	261	1,073	419	654		881	192				1,073	
3,958	5,343	9,301	6,710	2,591		4,243	977	4,081		3,427	5,874	

(1) Assigned reserves represent recoverable coal reserves that we have committed to mine at locations operating as of December 31, 2007. Unassigned reserves represent coal at suspended locations and coal that has not been committed. These reserves would require new mine development, mining equipment or plant facilities before operations could begin on the property.

(2) Compliance coal is defined by Phase II of the Clean Air Act as coal having sulfur dioxide content of 1.2 pounds or less per million Btu. Non-compliance coal is defined as coal having sulfur dioxide content in excess of this standard. Electricity generators are able to use coal that exceeds these specifications by using emissions reduction technology, using emissions allowance credits or blending higher sulfur coal with lower sulfur coal.

(3) As-received Btu per pound includes the weight of moisture in the coal on an as sold basis. The following table reflects the average moisture content used in the determination of the as-received Btu by region. The range of variability of the moisture content in coal across a given region may affect the actual shipped Btu content of current production from assigned reserves.

Midwest:	
Illinois	14.0%
Indiana	15.0%
Kentucky	12.5%
Powder River Basin:	
Montana	26.5%
Wyoming	27.5%
Southwest:	
Arizona	13.0%
Colorado	14.0%
New Mexico	15.5%
Australia	10.0%

(4) These joint ventures are consolidated in our results and their proven and probable coal reserves are reflected at 100%. Our effective percentage interest in each operation is as follows: Wambo Open-Cut 75.0%; Baralaba 62.5% and Millennium 84.6%.

(5) Proven and probable coal reserves for these joint ventures reflect our proportional ownership as indicated parenthetically.

(6) Proven and probable reserves exclude approximately 46 million tons located in Zulia State, Venezuela, related to the Las Carmelitas Project, which is held through our 51% interest in Excelven Pty Ltd.

Item 3. ***Legal Proceedings***

From time to time, we or our subsidiaries are involved in legal proceedings arising in the ordinary course of business or related to indemnities or historical operations. We believe we have recorded adequate reserves for these liabilities and that there is no individual case pending that is likely to have a material adverse effect on our financial condition, results of operations or cash flows. We discuss our significant legal proceedings below.

Litigation Relating to Continuing Operations

Navajo Nation Litigation

On June 18, 1999, the Navajo Nation served three of our subsidiaries, including Peabody Western Coal Company (Peabody Western), with a complaint that had been filed in the U.S. District Court for the District of Columbia. The Navajo Nation has alleged 16 claims, including Civil Racketeer Influenced and Corrupt Organizations Act (RICO) violations and fraud. The complaint alleges that the defendants jointly participated in unlawful activity to obtain favorable coal lease amendments. The plaintiff is seeking various remedies including actual damages of at least $600 million, which could be trebled under the RICO counts, punitive

damages of at least $1 billion, a determination that Peabody Western s two coal leases have terminated due to Peabody Western s breach of these leases and a reformation of these leases to adjust the royalty rate to 20%. Subsequently, the court allowed the Hopi Tribe to intervene in this lawsuit and the Hopi Tribe is also seeking unspecified actual damages, punitive damages and reformation of its coal lease. One of our subsidiaries named as a defendant is now a subsidiary of Patriot. However, we are responsible for this litigation under the Separation Agreement entered into with Patriot in connection with the spin-off. On February 9, 2005, the U.S. District Court for the District of Columbia granted a consent motion to stay the litigation until further order of the court. Peabody Western, the Navajo Nation, the Hopi Tribe and the owners of the power plants served by the suspended Black Mesa mine and the Kayenta mine have terminated the mediation with respect to this litigation and other business issues, filed a status report with the Court and asked the Court to lift the stay. The Court has not lifted the stay.

The outcome of this litigation is subject to numerous uncertainties. Based on our evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, we believe this matter is likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Salt River Project Agricultural Improvement and Power District Mine Closing and Retiree Health Care

Salt River Project and the other owners of the Navajo Generating Station filed a lawsuit on September 27, 1996, in the Superior Court of Maricopa County in Arizona seeking a declaratory judgment that certain costs relating to final reclamation, environmental monitoring work and mine decommissioning and costs primarily relating to retiree health care benefits are not recoverable by our subsidiary, Peabody Western, under the terms of a coal supply agreement dated February 18, 1977. The contract expires in 2011. The trial court subsequently ruled that the mine decommissioning costs were subject to arbitration but that the retiree health care costs were not subject to arbitration. We have recorded a receivable for mine decommissioning costs of $87.7 million and $76.8 million included in Investments and other assets in the consolidated balance sheets as of December 31, 2007 and 2006, respectively. The parties have negotiated a final comprehensive settlement and are in the process of obtaining all required approvals of the settlement documents.

Gulf Power Company Litigation

On June 22, 2006, Gulf Power Company filed a breach of contract lawsuit against one of our subsidiaries in the U.S. District Court, Northern District of Florida, contesting the force majeure declaration by our subsidiary under a coal supply agreement with Gulf Power Company and seeking damages for alleged past and future tonnage shortfalls of nearly 5 million tons under the agreement, which expired on December 31, 2007. We have filed a motion to dismiss the Florida lawsuit or to transfer it to Illinois. The Court held an evidentiary hearing on our motion to dismiss or transfer and has continued to stay discovery until the Court rules on the motion.

The outcome of this litigation is subject to numerous uncertainties. Based on our evaluation of the issues and their potential impact, the amount of any future loss cannot reasonably be estimated. However, based on current information, we believe this matter is likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Claims and Litigation Relating to Indemnities or Historical Operations

Oklahoma Lead Litigation

Gold Fields Mining, LLC (Gold Fields) is a dormant, non-coal producing entity that was previously managed and owned by Hanson PLC, our predecessor owner. In a February 1997 spin-off, Hanson PLC transferred ownership of

Gold Fields to us, despite the fact that Gold Fields had no ongoing operations and we had no prior involvement in its past operations. Gold Fields is currently one of our subsidiaries. We indemnified TXU Group with respect to certain claims relating to a former affiliate of Gold Fields. A predecessor of Gold Fields formerly operated two lead mills near Picher, Oklahoma prior to the 1950s and

mined, in accordance with lease agreements and permits, approximately 0.15% of the total amount of the crude ore mined in the county.

Gold Fields and two other companies are defendants in two class action lawsuits allegedly involving past operations near Picher, Oklahoma. The plaintiffs have asserted claims predicated on allegations of intentional lead exposure by the defendants and are seeking compensatory damages, punitive damages and the implementation of medical monitoring and relocation programs for the affected individuals. Gold Fields was also a defendant, along with other companies, in personal injury lawsuits that at one time involved over 50 individuals, arising out of the same lead mill operations. Gold Fields, along with the former affiliate, has settled most of the claims in the personal injury lawsuits and the remaining lawsuits have been dismissed with prejudice. In December 2003, the Quapaw Indian tribe and certain Quapaw land owners filed a lawsuit against Gold Fields, five other companies and the United States. The plaintiffs are seeking compensatory and punitive damages based on a variety of theories. In December 2007, the court dismissed the tribe s medical monitoring claim. Gold Fields has filed a third-party complaint against the United States and other parties. In February 2005, the state of Oklahoma on behalf of itself and several other parties sent a notice to Gold Fields and other companies regarding a possible natural resources damage claim. All of the lawsuits are pending in the U.S. District Court for the Northern District of Oklahoma.

The outcome of litigation and these claims are subject to numerous uncertainties. Based on our evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, we believe this matter is likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Environmental Claims and Litigation

Environmental claims have been asserted against Gold Fields related to activities of Gold Fields or a former affiliate. Gold Fields or the former affiliate has been named a potentially responsible party (PRP) at five national priority list sites based on the Superfund Amendments and Reauthorization Act of 1986. Claims were asserted at 12 additional sites, the total of which have since been reduced to 12 by completion of work, transfer or regulatory inactivity. The number of PRP sites in and of itself is not a relevant measure of liability, because the nature and extent of environmental concerns varies by site, as does the estimated share of responsibility for Gold Fields or the former affiliate. Undiscounted liabilities for environmental cleanup-related costs for all of the sites noted above were $42.4 million as of December 31, 2007 and $43.0 million as of December 31, 2006, $7.1 million and $14.4 million of which was reflected as a current liability, respectively. These amounts represent those costs that we believe are probable and reasonably estimable. In September 2005, Gold Fields and other PRPs received a letter from the U.S. Department of Justice alleging that the PRPs mining operations caused the Environmental Protection Agency (EPA) to incur approximately $125 million in residential yard remediation costs at Picher, Oklahoma and will cause the EPA to incur additional remediation costs relating to historical mining sites. Gold Fields has participated in the settlement discussions. Gold Fields believes it has meritorious defenses to these claims. Gold Fields is involved in other litigation in the Picher area, and we indemnified TXU Group with respect to a defendant as is more fully discussed under the Oklahoma Lead Litigation caption above. Significant uncertainty exists as to whether claims will be pursued against Gold Fields in all cases, and where they are pursued, the amount of the eventual costs and liabilities, which could be greater or less than this provision. Based on our evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, we believe these claims and litigation are likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Other

In addition, at times we become a party to other claims, lawsuits, arbitration proceedings and administrative procedures in the ordinary course of business in the U.S., Australia and other countries where we do business. Based on current information, we believe that the ultimate resolution of such other pending or threatened proceedings is not reasonably likely to have a material adverse effect on our financial position, results of operations or liquidity.

New York Office of the Attorney General Subpoena

The New York Office of the Attorney General sent a letter to us dated September 14, 2007. The letter referred to our plans to build new coal-fired electric generating units, and said that the increase in CO_2 emissions from the operation of these units, in combination with Peabody Energy s other coal-fired power plants, will subject Peabody Energy to increased financial, regulatory, and litigation risks. We currently have no electrical generating capacity in place. The letter included a subpoena issued under New York state law, which seeks information and documents relating to our analysis of the risks associated with climate change and possible climate change legislation or regulations, and our disclosure of such risks to investors. We believe that we made full and proper disclosure of these potential risks.

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, 2007.

Executive Officers of the Company

Set forth below are the names, ages as of February 15, 2008 and current positions of our executive officers. Executive officers are appointed by, and hold office at the discretion of, our Board of Directors.

Name	Age	Position
Gregory H. Boyce	53	Chairman and Chief Executive Officer, Director
Richard A. Navarre	47	President, Chief Commercial Officer and Chief Financial Officer
Sharon D. Fiehler	51	Executive Vice President and Chief Administrative Officer
Eric Ford	53	Executive Vice President and Chief Operating Officer
Alexander C. Schoch	53	Executive Vice President and Chief Legal Officer
Roger B. Walcott, Jr.	51	Executive Vice President
Ian S. Craig	54	Managing Director Australia Operations
Kemal Williamson	48	Group Vice President U.S. Western Operations
Rick Bowen	52	Senior Vice President, Btu Conversion and Strategic Planning

Gregory H. Boyce was elected Chairman of the Board on October 10, 2007 and has been a director of the Company since March 2005. He was named Chief Executive Officer Elect of the Company in March 2005, and assumed the position of Chief Executive Officer in January 2006. He also serves as President of the Company, a position he has held since October 2003. He was Chief Operating Officer of the Company from October 2003 to December 2005. He previously served as Chief Executive Energy of Rio Tinto plc (an international natural resource company) from 2000 to 2003. Other prior positions include President and Chief Executive Officer of Kennecott Energy Company from 1994 to 1999 and President of Kennecott Minerals Company from 1993 to 1994. He has extensive engineering and operating experience with Kennecott and also served as Executive Assistant to the Vice Chairman of Standard Oil of Ohio from 1983 to 1984. Mr. Boyce is Vice Chairman of the World Coal Institute, Co-Chairman of the Coal Based Generation Stakeholders Group, and a member of the Coal Industry Advisory Board of the International Energy Agency, the Advisory Council of the University of Arizona s Department of Mining and Geological Engineering and the National Council of the School of Engineering and Applied Science at Washington University in St. Louis. He is a board member of the Business Roundtable, the Center for Energy and Economic Development, the National Mining Association and the National Coal Council. He is a member of the Board of Trustees of the St. Louis Children s

Hospital; the School of Engineering and Applied Science National Council of Washington University in St. Louis; and the Advisory Council of the University of Arizona s Department of Mining and Geological Engineering.

Richard A. Navarre was named our President and Chief Commercial Officer in January 2008. He served as our Executive Vice President of Corporate Development from July 2006 to January 2008 and as Chief Financial Officer since October 1999. Mr. Navarre will continue to serve as our Chief Financial Officer until his successor is elected. He is a member of the Hall of Fame of the College of Business at Southern Illinois University Carbondale, a member of the Board of Advisors of the College of Business and Administration of Southern Illinois University Carbondale, a member of the International Business Advisory Board of the University of Missouri-St. Louis, a Director of the United Way of Greater St. Louis, a Director of the Missouri Historical Society, a member of Financial Executives International and the Civic Entrepreneurs Organization, and a former chairman of the Bituminous Coal Operators Association.

Sharon D. Fiehler has been our Executive Vice President and Chief Administrative Officer since January 2008, with executive responsibility for employee development, benefits, compensation, employee relations, affirmative action programs, information services, flight services, facilities management and procurement. From April 2002 to January 2008, she served as our Executive Vice President of Human Resources and Administration. Ms. Fiehler joined us in 1981 as Manager Salary Administration and has held a series of employee relations, compensation and salaried benefits positions. She holds degrees in social work and psychology and a MBA, and prior to joining us was a personnel representative for Ford Motor Company. Ms. Fiehler is a member of the Executive Committee and Board of Directors of Junior Achievement of St. Louis, a Board member of the Chancellor s Council of the University of Missouri-St. Louis and a member of the Board of Trustees of the St. Louis Zoo.

Eric Ford was named our Executive Vice President and Chief Operating Officer in March 2007, with responsibility for all of our global mining operations, as well as the areas of safety, operations improvement, engineering, and technical services. Mr. Ford has 35 years of extensive international management, operating and engineering experience, and most recently served as Chief Executive Officer of Anglo Coal Australia Pty Ltd. He joined Anglo Coal in 1971 and, after a series of increasingly complex operating assignments, was appointed President and Chief Executive Officer of Anglo American s joint venture coal mining operation in Colombia in 1998. In 2000, he returned to Anglo American Corporation as Executive Director of Operations for Anglo Platinum Corporation Limited. He was subsequently appointed Chief Executive Officer of Anglo Coal Australia Pty Ltd in 2001. Mr. Ford holds a Master of Science degree in Management Science from Imperial College in London and a Bachelor of Science degree in Mining Engineering (cum laude) from the University of the Witwatersrand in Johannesburg, South Africa. He is currently Deputy Chairman and a member of the Executive Committee of the Coal Industry Advisory Board of the International Energy Agency, and is Vice Chairman and Director of the Minerals Council of Australia.

Alexander C. Schoch was named our Executive Vice President and Chief Legal Officer in October 2006, with responsibility for all of our legal and corporate secretary functions. Prior to joining us, Mr. Schoch served as Vice President and General Counsel for Emerson Process Management, an operating segment of Emerson Electric Company and leading supplier of process-automation products. Mr. Schoch also served in several legal positions with Goodrich Corporation, a global supplier to the aerospace and defense industries, from 1987 to 2004, including Vice President, Associate General Counsel and Secretary. Prior to that, he worked for Marathon Oil Company as an attorney in its international exploration and production division. Mr. Schoch holds a Juris Doctorate from Case Western Reserve University in Ohio, as well as a Bachelor of Arts in Economics from Kenyon College in Ohio. He is admitted to practice law in several states, and is a member of the American and International Bar Associations.

Roger B. Walcott, Jr. became Executive Vice President in January 2008. He served as Executive Vice President Strategy and Business Services from May 2006 to January 2008. Prior to that, Mr. Walcott served as our Executive Vice President Resource Management and Strategic Planning from July 2005 to May 2006 and as our Executive Vice President Corporate Development from February 2001 to July 2005. He joined us in June 1998 as Executive Vice President. From 1987 to 1998, he was a Senior Vice President and a director with The Boston Consulting Group, where he served a variety of clients in strategy and operational assignments. He joined Boston Consulting Group in

1981, and was Chairman of The Boston Consulting Group s Human Resource Capabilities Committee. Mr. Walcott holds a MBA with high distinction from the Harvard Business School. Mr. Walcott intends to retire from the Company on June 1, 2008.

Ian S. Craig was named our Managing Director Australia Operations in September 2004. From May 2004 to August 2004, Mr. Craig served as Group Executive Technical Services. He was Group Executive Powder River Basin Operations from July 2001 to April 2004. Prior to that, he was Managing Director of a former Peabody subsidiary in Australia. Mr. Craig also held a number of management positions within the subsidiary company and other Australian mining organizations. He holds a Bachelor of Applied Science Degree in Mineral Engineering from the South Australian Institute of Technology. Mr. Craig is a Fellow of The Australasian Institute of Mining and Metallurgy. Mr. Craig will retire from the Company on February 29, 2008.

Kemal Williamson became our Group Vice President U.S. Western Operations in July 2005. After joining us in September 2000, Mr. Williamson served as Group Executive Midwest Operations until April 2004, and then was Group Executive Powder River Basin Operations until July 2005. He has extensive mining engineering and operations experience in the United States and Australia. Mr. Williamson holds a Bachelor of Science Degree in Mining Engineering from Pennsylvania State University and a MBA from Kellogg Graduate School of Management, Northwestern University.

Rick Bowen became Senior Vice President of Btu Conversion and Strategic Planning in January 2008, with responsibility for project and business development for planned electric generating initiatives and projects for technologies to transform the energy in coal into other high-demand energy forms, as well as our strategic planning function. He served as President of Generation and Btu Conversion from July 2006 to January 2008. Mr. Bowen joined us in September 2004 as Corporate Senior Vice President and President of Generation. Prior to joining us, Mr. Bowen served for 18 years with Dynegy Inc. and its predecessor companies. Mr. Bowen is a member of the Industry Advisory Board and the Consortium for Electric Reliability Technology Solutions. He is also a member of the Board of Directors of Econo-Power International Corporation and holds the Advisory Board seat on GreatPoint Energy. Mr. Bowen holds a Bachelor of Science in Business Administration and a MBA from the University of Houston.

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, under the symbol BTU. As of February 15, 2008, there were 1,074 holders of record of our common stock.

The table below sets forth the range of quarterly high and low sales prices for our common stock (after giving retroactive effect to the two-for-one stock split effective February 22, 2006) on the New York Stock Exchange during the calendar quarters indicated.

	High	Low
2006		
First Quarter	$ 52.54	$ 41.24
Second Quarter	76.29	46.81
Third Quarter	59.90	32.94
Fourth Quarter	48.59	34.05
2007		
First Quarter	$ 44.60	$ 36.20
Second Quarter	55.76	39.96

Third Quarter	50.99	38.42
Fourth Quarter	62.55	47.52

Dividend Policy

We paid quarterly dividends totaling $0.24 per share during the years ended December 31, 2007 and 2006. Most recently, our Board of Directors declared a dividend of $0.06 per share of Common Stock on January 29, 2008, payable on March 4, 2008, to stockholders of record on February 12, 2008. The declaration and payment of dividends and the amount of dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt instruments and other factors deemed relevant by our Board of Directors; however, we presently expect that dividends will continue to be paid. Limitations on our ability to pay dividends imposed by our debt instruments are discussed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Share Repurchases

Share Repurchase Program

In July 2005, our Board of Directors authorized a share repurchase program of up to 5% of the then outstanding shares of our common stock, approximately 13.1 million shares. The repurchases may be made from time to time based on an evaluation of our outlook and general business conditions, as well as alternative investment and debt repayment options. As of December 31, 2007, there were approximately 10.9 million shares available for repurchase. There were no share repurchases under this program in the year ended December 31, 2007.

Share Relinquishment

During the year ended December 31, 2007, we received 137,625 shares of common stock as consideration for employees exercise of stock options and to pay estimated taxes at the vesting date of restricted stock. The value of the common stock tendered by employees to exercise stock options and to settle taxes on restricted stock was based upon the closing price on the dates of the respective transactions.

Period	Total Number of Shares Purchased[1]	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Publicly Announced Program
October 1 through October 31, 2007	78,516	$ 55.30		10,920,605
November 1 through November 30, 2007	57,541	49.36		10,920,605
December 1 through December 31, 2007				10,920,605
Total	136,057	$ 52.79		

(1) Represents shares withheld to cover the estimated withholding taxes at the vesting date of restricted stock.

Item 6. ***Selected Financial Data.***

The following table presents selected financial and other data about us for the most recent five fiscal years. The following table and the discussion of our results of operations in 2007 and 2006 in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations includes references to, and analysis of, our Adjusted EBITDA results. Adjusted EBITDA is defined as income from continuing operations before deducting early debt extinguishment costs, net interest expense, income taxes, minority interests, asset retirement obligation expense and depreciation, depletion and amortization. Adjusted EBITDA is used by management to measure operating performance, and management also believes it is a useful indicator of our ability to meet debt service and capital expenditure requirements. Because Adjusted EBITDA is not calculated identically by all companies, our calculation may not be comparable to similarly titled measures of other companies.

The selected financial data for all periods presented reflect the assets, liabilities and results of operations from subsidiaries spun-off as Patriot Coal Corporation as discontinued operations.

In October 2006, we acquired Excel Coal Limited and our results of operations for the year ended December 31, 2006 included the results of operations of the three operating mines and three development-stage mines (all of which are operating as of December 31, 2007) in New South Wales, Australia and Queensland, Australia from the date of acquisition.

On April 15, 2004, we acquired three coal operations from RAG Coal International AG. Our results of operations for the year ended December 31, 2004 include the results of operations of the two mines in Queensland, Australia and the results of operations of the Twentymile Mine in Colorado from the April 15, 2004 purchase date.

Results of operations for the year ended December 31, 2003 included early debt extinguishment costs of $53.5 million pursuant to our debt refinancing in the first half of 2003. In addition, results included expense relating to the cumulative effect of accounting changes, net of income taxes, of $10.1 million. This amount represents the aggregate amount of the recognition of accounting changes pursuant to the adoption of SFAS No. 143, Accounting for Asset Retirement Obligations, the change in method of amortization of actuarial gains and losses related to net periodic postretirement benefit costs and the effect of the rescission of Emerging Issues Task Force No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities.

We have derived the selected historical financial data as of and for the years ended December 31, 2007, 2006, 2005, 2004 and 2003 from our audited financial statements. You should read the following table in conjunction with the financial statements, the related notes to those financial statements and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

The results of operations for the historical periods included in the following table are not necessarily indicative of the results to be expected for future periods. In addition, the Risk Factors section of Item 1A of this report includes a discussion of risk factors that could impact our future results of operations.

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(Dollars in thousands, except share and per share data and tons sold)				
Results of Operations Data					
Revenues					
Sales	$ 4,364,708	$ 4,002,403	$ 3,584,422	$ 2,732,972	$ 2,142,767
Other revenues	210,004	105,993	81,754	82,186	82,783
Total revenues	4,574,712	4,108,396	3,666,176	2,815,158	2,225,550
Costs and Expenses					
Operating costs and expenses	3,574,818	3,155,732	2,885,320	2,252,949	1,745,616
Depreciation, depletion and amortization	361,559	294,270	253,788	211,630	180,262
Asset retirement obligation expense	25,610	15,830	20,329	15,125	13,226
Selling and administrative expenses	147,146	128,031	132,679	84,534	66,688
Other operating income:					
Net gain on disposal or exchange of assets	(88,684)	(53,532)	(44,445)	(18,065)	(9,382)
(Income) loss from equity affiliates	(14,461)	(22,791)	(15,227)	(64)	538
Operating Profit	568,724	590,856	433,732	269,049	228,602
Interest expense	235,236	137,668	98,066	89,052	90,754
Early debt extinguishment costs	(253)	1,396		1,751	53,513
Interest income	(7,094)	(11,309)	(9,088)	(3,999)	(2,126)
Income From Continuing Operations Before Income Taxes and Minority Interests	340,835	463,101	344,754	182,245	86,461
Income tax provision (benefit)	(78,112)	(90,084)	63,779	281	(8,017)
Minority interests	(2,316)	611	2,472	1,007	3,035
Income From Continuing Operations	421,263	552,574	278,503	180,957	91,443
Income (loss) from discontinued operations	(156,978)	48,123	144,150	(5,570)	(49,951)

Income before accounting changes	264,285	600,697	422,653	175,387	41,492
Cumulative effect of accounting changes					(10,144)
Net Income	$ 264,285	$ 600,697	$ 422,653	$ 175,387	$ 31,348
Basic Earnings Per Share From Continuing Operations	$ 1.60	$ 2.10	$ 1.06	$ 0.73	$ 0.43
Diluted Earnings Per Share From Continuing Operations	$ 1.56	$ 2.05	$ 1.04	$ 0.71	$ 0.42
Weighted average shares used in calculating basic earnings per share	264,068,180	263,419,344	261,519,424	248,732,744	213,638,084
Weighted average shares used in calculating diluted earnings per share	269,166,290	269,166,005	268,013,476	254,812,632	219,342,512
Dividends Declared Per Share	$ 0.24	$ 0.24	$ 0.17	$ 0.13	$ 0.11
Other Data					
Tons sold (in millions)	237.8	223.3	216.1	202.6	182.2
Net cash provided by (used in) continuing operations:					
Operating activities	$ 447,181	$ 591,412	$ 683,804	$ 454,958	$ 314,819
Investing activities	(541,730)	(2,061,159)	(516,453)	(760,880)	(308,792)
Financing activities	44,768	1,407,581	(38,876)	577,426	39,184
Adjusted EBITDA[1]	955,893	900,956	707,849	495,804	422,090
Additions to property, plant, equipment and mine development	470,434	397,497	450,348	115,164	81,893
Federal coal lease expenditures	178,193	178,193	118,364	114,653	
Acquisitions, net		1,507,775		426,571	90,000
Balance Sheet Data (at period end)					
Total assets	$ 9,668,307	$ 9,514,056	$ 6,852,006	$ 6,178,592	$ 5,280,265
Total debt	3,273,100	3,277,032	1,332,047	1,362,738	1,134,161
Total stockholders equity	2,519,671	2,338,526	2,178,467	1,724,592	1,132,057

(1) Adjusted EBITDA is defined as income from continuing operations before deducting early debt extinguishment costs, net interest expense, income taxes, minority interests, asset retirement obligation expense and depreciation, depletion and amortization. Adjusted EBITDA is used by management to measure operating performance, and management also believes it is a useful indicator of our ability to meet debt service and capital expenditure requirements. Because Adjusted EBITDA is not calculated identically by all companies, our calculation may not be comparable to similarly titled measures of other companies.

Adjusted EBITDA is calculated as follows (unaudited):

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(Dollars in thousands)				
Income from continuing operations	$ 421,263	$ 552,574	$ 278,503	$ 180,957	$ 91,443
Income tax provision (benefit)	(78,112)	(90,084)	63,779	281	(8,017)
Depreciation, depletion and amortization	361,559	294,270	253,788	211,630	180,262
Asset retirement obligation expense	25,610	15,830	20,329	15,125	13,226
Interest expense	235,236	137,668	98,066	89,052	90,754
Early debt extinguishment costs	(253)	1,396		1,751	53,513
Interest income	(7,094)	(11,309)	(9,088)	(3,999)	(2,126)
Minority interests	(2,316)	611	2,472	1,007	3,035
Adjusted EBITDA	$ 955,893	$ 900,956	$ 707,849	$ 495,804	$ 422,090

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

Overview

We are the largest private sector coal company in the world, with majority interests in 31 coal operations located throughout all major U.S. coal producing regions, except Appalachia, and international interests in Australia and Venezuela. In 2007, we sold 237.8 million tons of coal. Our U.S. sales represented 19% of all U.S. coal sales and were approximately 80% greater than the sales of our closest U.S. competitor.

United States coal demand was approximately 1.1 billion tons in 2007, based on Energy Information Administration (EIA) estimates. Coal s predominate use is for baseload electricity requirements. For the 12 months ended November 2007, coal s share of electricity generation was approximately 50%, a share that the EIA projects will grow to 55% by 2030. EIA projects an additional 130 gigawatts of new U.S. coal-fueled generation by 2030, including 9 gigawatts at coal-to-liquids plants and 45 gigawatts at integrated gasification combined-cycle plants, which represents more than 500 million tons of additional coal demand. Domestic coal consumption is expected to grow at an average annual rate of 1.8% from 2007 through 2030 when U.S. coal demand is forecasted to reach 1.7 billion tons. Coal production located west of the Mississippi River is projected to provide most of the incremental growth as Western production increases to an estimated 65% share of total production in 2030 versus 58% in 2007.

Globally, we believe that coal demand is driven by electricity generation (65%) and industrial use (31%), including steel making. The International Energy Agency (IEA) estimates coal s share of total world energy consumption is projected to increase from 25% in 2005 to 28% through 2030, and in the electric power sector, its share is estimated to rise from 43% in 2004 to 45% in 2030. More than 80% of the growth in global coal demand is expected to come from China and India. These two countries comprise approximately 45% of global coal use, which is projected by IEA to grow to 80% by 2030. China alone added an estimated 96 gigawatts of new coal-fueled generation in 2007, representing more than 300 million tons of annual coal use. Coal demand in India is forecasted to nearly triple by 2030. In total, global coal consumption is expected to grow 73%, or more than 4 billion tons by 2030.

Our primary U.S. customers are utilities, which accounted for 85% of our sales in 2007. Our international production is sold primarily into export markets. Our international activities accounted for 13% of our sales by volume in 2007. We typically sell coal to utility customers under long-term contracts (those with terms longer than one year). During 2007, approximately 94% of our sales were under long-term contracts. As of December 31, 2007, production totaled 214.1 million tons and sales totaled 237.8 million tons. As discussed more fully in Item 1A. Risk Factors, our results of operations in the near-term could be negatively impacted by poor weather conditions, unforeseen geologic conditions or equipment problems at mining locations, and by the availability of transportation for coal shipments. On a long-term basis, our results of operations could

be impacted by our ability to secure or acquire high-quality coal reserves, find replacement buyers for coal under contracts with comparable terms to existing contracts, or the passage of new or expanded regulations that could limit our ability to mine, increase our mining costs, or limit our customers ability to utilize coal as fuel for electricity generation. In the past, we have achieved production levels that are relatively consistent with our projections. However, we expect to adjust our production levels in response to changes in market demand.

We conduct business through four principal operating segments: Western U.S. Mining, Eastern U.S. Mining, Australian Mining, and Trading and Brokerage. Our Western U.S. Mining operations consist of our Powder River Basin, Southwest and Colorado operations, and our Eastern U.S. Mining operations consist of our Illinois and Indiana operations. The principal business of the Western and Eastern U.S. Mining segments is the mining, preparation and sale of steam coal, sold primarily to electric utilities.

Geologically, Western operations mine bituminous and subbituminous coal deposits and Eastern operations mine bituminous coal deposits. Our Western U.S. Mining operations are characterized by predominantly surface extraction processes, lower sulfur content and Btu of coal, and higher customer transportation costs (due to longer shipping distances). Our Eastern U.S. Mining operations are characterized by a mix of surface and underground extraction processes, higher sulfur content and Btu of coal, and lower customer transportation costs (due to shorter shipping distances).

Australian Mining operations are characterized by both surface and underground extraction processes, mining various qualities of low-sulfur, high Btu coal (metallurgical coal) as well as steam coal primarily sold to an international customer base with a small portion sold to Australian steel producers and power generators. In the second half of 2006, through two separate transactions, we acquired Excel Coal Limited (Excel), an independent coal company in Australia for a total acquisition price of US$1.51 billion, net of cash received, plus approximately $293.0 million in assumed debt. See Liquidity and Capital Resources for information on the financing of the Excel transaction. Assets acquired include three operating mines and three development-stage mines, along with up to 500 million tons of proven and probable coal reserves.

We own a 25.5% interest in Carbones del Guasare, which owns and operates the Paso Diablo Mine in Venezuela. The Paso Diablo Mine produces approximately 6 to 8 million tons of steam coal annually for export to the United States and Europe. During 2007, the Paso Diablo Mine contributed $21.2 million to segment Adjusted EBITDA in Corporate and Other Adjusted EBITDA and paid a dividend of $12.9 million. At December 31, 2007, our investment in Paso Diablo was $68.4 million.

Metallurgical coal is produced primarily from four of our Australian mines. Metallurgical coal is approximately 4% of our total sales volume, but represents a larger share of our revenue, approximately 15% in 2007.

In addition to our mining operations, which comprised 92% of revenues in 2007, we generate revenues and additional cash flows from our Trading and Brokerage operations (7% of revenues), and other activities, including transactions utilizing our vast natural resource position (selling non-core land holdings and mineral interests).

We continue to pursue the development of coal-fueled generating projects in areas of the U.S. where electricity demand is strong and where there is access to land, water, transmission lines and low-cost coal. The projects involve mine-mouth generating plants using our surface lands and coal reserves. Our ultimate role in these projects could take numerous forms, including, but not limited to, equity partner, contract miner or coal sales. We own 5.06% of the 1,600-megawatt Prairie State Energy Campus that is under construction in Washington County, Illinois. We are pursuing development of the 1,500-megawatt Thoroughbred Energy Campus in Muhlenberg County, Kentucky. The plants, assuming all necessary permits and financing are obtained and following selection of partners and sale of a majority of the output of each plant, could be operational following a four-year construction phase.

The EIA projects that the high price of oil will lead to an increase in demand for unconventional sources of transportation fuel, including Btu Conversion technologies, and that coal will increase its share as a fuel for electricity generation. We are exploring several Btu Conversion projects, which are designed to expand the

uses of coal through various technologies, and we are continuing to explore options particularly as they relate to Btu Conversion technologies such as coal-to-liquids and coal gasification.

In July 2005, our Board of Directors authorized a share repurchase program of up to 5% of the outstanding shares of our common stock. The repurchases may be made from time to time based on an evaluation of our outlook and general business conditions, as well as alternative investment and debt repayment options. In 2006, we repurchased 2.2 million of our common shares for $99.8 million under this repurchase program.

On October 31, 2007, we spun-off portions of our Eastern U.S. Mining operations business segment to form Patriot. We distributed Patriot stock to our stockholders at a ratio of one share of Patriot stock for every 10 shares of Peabody stock held on the record date of October 22, 2007. Our results for all periods presented reflect Patriot as a discontinued operation. The spin-off included eight company-operated mines, two majority-owned joint venture mines, and numerous contractor operated mines serviced by eight coal preparation facilities along with 1.2 billion tons of proven and probable coal reserves. Prior to the spin-off, we received necessary regulatory approvals including a private letter ruling on the tax-free nature of the transaction from the Internal Revenue Service.

Results of Operations

The portions of the Eastern U.S. Mining operations business segment that were included in the spin-off of Patriot have been classified as discontinued operations and are excluded from the operating results for all periods presented. See the description of the spin-off in Part I, Item 1 Discontinued Operations.

Adjusted EBITDA

The discussion of our results of operations below includes references to and analysis of our segments Adjusted EBITDA results. Adjusted EBITDA is defined as income from continuing operations before deducting early debt extinguishment costs, net interest expense, income taxes, minority interests, asset retirement obligation expense and depreciation, depletion and amortization. Adjusted EBITDA is used by management to measure our segments operating performance, and management also believes it is a useful indicator of our ability to meet debt service and capital expenditure requirements. Because Adjusted EBITDA is not calculated identically by all companies, our calculation may not be comparable to similarly titled measures of other companies. Adjusted EBITDA is reconciled to its most comparable measure, under generally accepted accounting principles, in Note 24 to our consolidated financial statements.

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

Summary

Higher average sales prices across all U.S. regions and increased volumes, primarily from Australian Mining operations, contributed to an 11.4% increase in revenues to $4.57 billion compared to 2006. Segment Adjusted EBITDA increased 3.4% to $1.06 billion primarily on higher prices in the Western U.S. and increased results from Trading and Brokerage operations. Increases in sales volumes and prices in our U.S. mining operations were partially offset by challenges experienced during the period such as ongoing shipping constraints from port congestion in Australia; geologic and equipment issues, higher commodity costs, as well as a weaker U.S. dollar against the Australian Dollar. Also, negatively impacting Australian Mining results was lower metallurgical coal prices associated with annual contracts that began in April 2007. Income from continuing operations was $421.3 million in 2007, or $1.56 per diluted share, a decrease of 23.8% from 2006 income from continuing operations of $552.6 million, or $2.05 per diluted share.

Tons Sold

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

	Year Ended December 31,		Increase	
	2007	2006	Tons	%
	(Tons in millions)			
Western U.S. Mining Operations	161.4	160.5	0.9	0.6%
Eastern U.S. Mining Operations	30.9	30.4	0.5	1.6%
Australian Mining Operations	21.4	11.0	10.4	94.5%
Trading and Brokerage Operations	24.1	21.4	2.7	12.6%
Total tons sold	237.8	223.3	14.5	6.5%

Revenues

The following table presents revenues for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2007	2006	$	%
	(Dollars in thousands)			
Western U.S. Mining Operations	$ 2,061,265	$ 1,703,445	$ 357,820	21.0%
Eastern U.S. Mining Operations	984,841	905,743	79,098	8.7%
Australian Mining Operations	1,161,093	843,194	317,899	37.7%
Trading and Brokerage Operations	320,692	652,029	(331,337)	(50.8)%
Other	46,821	3,985	42,836	1074.9%
Total revenues	$ 4,574,712	$ 4,108,396	$ 466,316	11.4%

In 2007, our total revenues were $4.57 billion, an increase of $466.3 million, or 11.4%, compared to the prior year, which resulted from sales price increases in all U.S. regions, most notably in our Powder River Basin operations and increased volumes from Australia. Volumes related to operations acquired in the October 2006 Excel acquisition accounted for 10.9 million tons of the increase to tons sold. Partially offsetting sales price and volume increases was the continued shift towards trading contracts versus brokerage contracts in our Trading and Brokerage operations. Trading and Brokerage operations sales decreased during the year as the amount of brokerage business was reduced and replacement business was in the form of traded contracts. Contracts for trading activity are recorded at net margin in other revenues, whereas contracts for brokerage activity are recorded at gross sales price to revenues and operating costs. While the shift to trading contracts reduced total sales, there was no impact to Adjusted EBITDA.

Overall, prices in our Western U.S. Mining operations increased due to a sales realization increase of approximately 29% for our premium Powder River Basin product and an average increase across all U.S. regions of 16%. In

addition, Eastern U.S. Mining revenues increased due to higher revenues from coal sold to synthetic fuel plants as those plants were idled for part of 2006. Offsetting this increase was lower average sales prices in our Australian Mining operations related to lower metallurgical contract pricing and a significant change in sales mix resulting in higher thermal export and domestic product sales. Volumes were unfavorably impacted at some of our Australian Mining operations as a result of damaged rails and further amplified port and rail congestion throughout the year, in addition to adverse weather events in the second quarter that affected production.

Segment Adjusted EBITDA

Our total segment Adjusted EBITDA was $1.06 billion for the year ended 2007, compared with $1.03 billion in the prior year. Details were as follows:

	Year Ended December 31,		Increase (Decrease) to Segment Adjusted EBITDA	
	2007	2006	$	%
	(Dollars in thousands)			
Western U.S. Mining Operations	$ 597,333	$ 473,074	$ 124,259	26.3%
Eastern U.S. Mining Operations	196,595	184,549	12,046	6.5%
Australian Mining Operations	159,473	278,411	(118,938)	(42.7)%
Trading and Brokerage Operations	110,169	92,604	17,565	19.0%
Total Segment Adjusted EBITDA	$ 1,063,570	$ 1,028,638	$ 34,932	3.4%

Adjusted EBITDA from our Western U.S. Mining operations increased $124.3 million, or 26.3%, during the year primarily related to the overall increase in average sales prices from our Powder River Basin operations. Partially offsetting higher average sales prices were higher costs associated with equipment repairs and maintenance and higher add-on taxes and royalties driven by higher sales prices compared to the prior year, mine shutdown for maintenance in our Colorado region in December, higher fuel costs and adverse weather conditions in the Powder River Basin and capital project delays in the first half of the year.

Eastern U.S. Mining operations Adjusted EBITDA increased $12.0 million, or 6.5%, compared to prior year as both volumes and prices per ton saw moderate increases. Results improved compared to prior year as benefits of higher volumes and sales prices were offset by higher costs for commodities, including fuel. The 2007 results were also positively impacted by higher revenues from coal sold to synthetic fuel facilities of $12.5 million as customers idled their synthetic fuel plants for a portion of 2006.

Our Australian Mining operations Adjusted EBITDA decreased $118.9 million, or 42.7%, compared to prior year primarily due to approximately $31 million of higher costs resulting from the weakening U.S. dollar (higher costs of approximately $112 million were offset by hedging gains of $81 million); higher congestion-related demurrage costs (approximately $50 million); lower pricing on annually repriced metallurgical coal contracts; and, rail and port congestion at Dalrymple Bay Coal Terminal and the Port of Newcastle. Dalrymple Bay Coal Terminal has been experiencing queues of over 41 vessels (approximately a 24-day load time) down from 50 vessels in the second quarter (approximately a 34-day delay). Partially offsetting these decreases were the full year contributions from our mines acquired in the Excel acquisition and a $6.3 million insurance recovery on a business interruption claim in the first half of 2007. Our Australian mines acquired in 2006 experienced shipping difficulties and damaged rail lines resulting from a storm late in the second quarter. The Port of Newcastle was closed for several days in June due to a storm, with up to 79 vessels in the queue (a 35-40 day wait). Queues at Newcastle have recently been reduced to 31 vessels (11-day wait).

Trading and Brokerage operations Adjusted EBITDA increased $17.6 million from the prior year, as 2007 results reflected higher international trading gains, resulting from higher volumes and pricing due to expanded global trading activities, strong supply/demand fundamentals and tightened seaborne market conditions.

Income From Continuing Operations Before Income Taxes and Minority Interests

The following table presents income before income taxes and minority interests for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase (Decrease) to Income	
	2007	2006	$	%
	(Dollars in thousands)			
Total Segment Adjusted EBITDA	$ 1,063,570	$ 1,028,638	$ 34,932	3.4%
Corporate and Other Adjusted EBITDA	(107,677)	(127,682)	20,005	15.7%
Depreciation, depletion and amortization	(361,559)	(294,270)	(67,289)	(22.9)%
Asset retirement obligation expense	(25,610)	(15,830)	(9,780)	(61.8)%
Interest expense and early debt extinguishment costs	(234,983)	(139,064)	(95,919)	(69.0)%
Interest income	7,094	11,309	(4,215)	(37.3)%
Income from continuing operations before income taxes and minority interests	$ 340,835	$ 463,101	$ (122,266)	(26.4)%

Income from continuing operations before income taxes and minority interests of $340.8 million for 2007 is $122.3 million, or 26.4%, lower than 2006 primarily due to higher interest expense and higher depreciation, depletion and amortization related to the acquisition of Excel in late 2006.

Corporate and Other Adjusted EBITDA results include selling and administrative expenses, equity income from our joint venture, net gains on asset disposals or exchanges, costs associated with past mining obligations and revenues and expenses related to our other commercial activities such as coalbed methane, generation development, Btu Conversion and resource management. The $20.0 million improvement in Corporate and Other Adjusted EBITDA (net expense) in 2007 compared to 2006 includes the following:

Higher gains on asset disposals and exchanges of $35.2 million. The 2007 activity included a gain of $26.4 million on the sale of approximately 172 million tons of coal reserves to the Prairie State equity partners. Our 2007 activity also included a gain of $50.5 million on the exchange of our coalbed methane and oil and gas rights in the Illinois Basin, West Virginia, New Mexico and the Powder River Basin for high-Btu coal reserves located in West Virginia and Kentucky and cash proceeds. In comparison, the 2006 activity included a $39.2 million gain on an exchange with the Bureau of Land Management of approximately 63 million tons of leased coal reserves at our Caballo mining operation for approximately 46 million tons of coal reserves contiguous with our North Antelope Rochelle mining operation and other gains on asset disposals totaling $14.3 million;

Higher past mining obligation expenses of $15.5 million resulting from increased retiree healthcare costs due to higher than anticipated healthcare utilization by retirees, particularly related to prescription drugs;

Higher selling and administrative expenses of $19.1 million during the year primarily resulting from the implementation of a new enterprise resource planning system and other corporate development initiatives; and

Lower equity income of $6.8 million from our 25.5% interest in Carbones del Guasare (owner and operator of the Paso Diablo Mine in Venezuela), which primarily resulted from trucking issues experienced earlier in the year, a temporary shortage of explosives, and delays in receiving equipment, which impacted operations.

Depreciation, depletion and amortization increased $67.3 million primarily related to the addition of the Australian operations acquired in late 2006.

Interest expense and early debt extinguishment costs increased $95.9 million primarily due to approximately $1.8 billion in new debt issued or assumed as part of the Excel acquisition in the second half of 2006.

Net Income

	Year Ended December 31,		Increase (Decrease) to Income	
	2007	2006	$	%
	(Dollars in thousands)			
Income from continuing operations before income taxes and minority interests	$ 340,835	$ 463,101	$ (122,266)	(26.4)%
Income tax benefit	78,112	90,084	(11,972)	(13.3)%
Minority interests	2,316	(611)	2,927	479.1%
Income from continuing operations	421,263	552,574	(131,311)	(23.8)%
Income (loss) from discontinued operations	(156,978)	48,123	(205,101)	(426.2)%
Net income	$ 264,285	$ 600,697	$ (336,412)	(56.0)%

Income from continuing operations decreased $131.3 million in 2007 compared to prior year due to the decrease in income from continuing operations before income taxes and minority interests discussed above and a lower income tax benefit compared to 2006. The decrease in the income tax benefit for the year ended 2007 related primarily to a $56.0 million foreign currency impact on deferred taxes as a result of increases in Australian dollar/U.S. dollar exchange rates and $33.2 million lower tax reserves than in the prior year, partially offset by lower pre-tax income, a $10.3 million increase in released valuation allowances, and $24.3 million of additional tax credits. Minority interests increased primarily from the absorption of losses in excess of the minority interest capital contribution at one of our mines, partially offset by lower earnings allocable to partners.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Summary

Higher average sales prices and increased volumes in the Eastern U.S., Powder River Basin and Australian Mining operations, including the October 2006 acquisition of three mines in Australia, contributed to a 12.1% increase in revenues to $4.11 billion compared to 2005. Segment Adjusted EBITDA increased 17.8% to $1.03 billion primarily on growth in international volumes and higher sales prices from our Australian Mining operations and increased contributions from Trading and Brokerage operations. Increases in sales volumes and prices in our U.S. mining operations were partially offset by operational challenges experienced during the period such as ongoing shipping constraints from rail performance in the Powder River Basin and port congestion in Australia; geologic and equipment issues as well as mine closures in our Western U.S. Mining operations in late 2005. Net income was $600.7 million in 2006, or $2.23 per diluted share, an increase of 42.1% over 2005 net income of $422.7 million, or $1.58 per diluted share.

Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2006 and 2005:

	Year Ended December 31,		Increase (Decrease)	
	2006	2005	Tons	%
	(Tons in millions)			
Western U.S. Mining Operations	160.5	154.3	6.2	4.0%
Eastern U.S. Mining Operations	30.4	28.7	1.7	5.9%
Australian Mining Operations	11.0	8.3	2.7	32.5%
Trading and Brokerage Operations	21.4	24.8	(3.4)	(13.7)%
Total tons sold	223.3	216.1	7.2	3.3%

Revenues

The table below presents revenues for the years ended December 31, 2006 and 2005:

	Year Ended December 31,		Increase (Decrease)	
	2006	2005	$	%
	(Dollars in thousands)			
Western U.S. Mining Operations	$ 1,703,445	$ 1,611,587	$ 91,858	5.7%
Eastern U.S. Mining Operations	905,743	760,404	145,339	19.1%
Australian Mining Operations	843,194	598,085	245,109	41.0%
Trading and Brokerage Operations	652,029	679,176	(27,147)	(4.0)%
Other	3,985	16,924	(12,939)	(76.5)%
Total revenues	$ 4,108,396	$ 3,666,176	$ 442,220	12.1%

In 2006, our total revenues were $4.11 billion, an increase of $442.2 million, or 12.1%, compared to prior year, which resulted from sales price increases in all regions, particularly in our Eastern and Australian operations and demand-driven sales volume increases in the Powder River Basin, Midwest and Australian operations. Volumes related to the October 2006 Excel acquisition accounted for 2.1 million tons of the increase to tons sold and approximately 43% of the increase to sales in Australia. Partially offsetting sales price increases were lower western regional sales due to the late 2005 mine closures in the Western U.S. Mining operations and lower brokerage volumes.

Overall, prices and volumes in our Western U.S. Mining operations increased, mainly reflecting increases to sales prices of over $0.70 per ton and volumes of 12.7 million tons in the Powder River Basin. These increases at our Powder River Basin operations resulted from strong demand for the mines low-sulfur products and improved rail conditions compared to 2005, when the region was dealing with major railroad maintenance. Despite rail performance improvements relative to 2005, constrained rail capacity continued to limit growth in the region in 2006.

Also, affecting Western U.S. Mining revenues was lower production due to the cessation of mining operations at our Seneca and Black Mesa mines in late 2005 and unfavorable geologic conditions and equipment issues at our Twentymile Mine.

Per ton sales prices in our Eastern U.S. Mining operations increased and sales volumes increased due primarily to our Gateway mine, which began operation in late 2005. Partially offset by the overall increase in 2006 total revenues was the customer idling of synfuel plants during 2006.

Revenues from our Australian Mining operations were $245.1 million, or 41.0%, higher than in 2005, primarily due to higher international metallurgical coal prices, higher production at our underground mine following installation of a new longwall in the second quarter of 2006 and additional volumes from our newly acquired mines ($105.1 million). A higher per ton sales price reflected higher contract prices in 2006 for metallurgical coal as well as the slower realization of metallurgical coal price increases in 2005 when we operated under some lower priced carry-over contracts from 2004 through most of the first nine months of 2005.

Brokerage operations revenues decreased $27.1 million in 2006 compared to 2005 due to lower sales volumes, partially offset by higher sales prices and proceeds of $28.2 million from settlement of commitments by a third-party coal producer following a brokerage contract restructuring.

Segment Adjusted EBITDA

Our total segment Adjusted EBITDA was $1.03 billion for the year ended 2006 compared with $873.5 million in 2005. Details were as follows:

Segment Adjusted EBITDA

	Year Ended December 31,		Increase to Segment Adjusted EBITDA	
	2006	2005	$	%
	(Dollars in thousands)			
Western U.S. Mining Operations	$ 473,074	$ 459,039	$ 14,035	3.1%
Eastern U.S. Mining Operations	184,549	168,793	15,756	9.3%
Australian Mining Operations	278,411	202,582	75,829	37.4%
Trading and Brokerage Operations	92,604	43,058	49,546	115.1%
Total Segment Adjusted EBITDA	$ 1,028,638	$ 873,472	$ 155,166	17.8%

Adjusted EBITDA from our Western U.S. Mining operations increased $14.0 million, or 3.1%, during 2006 primarily reflecting an increase in sales volumes of 12.7 million tons at our Powder River Basin operations, which resulted from continued strong demand and improved rail performance relative to 2005. Western U.S. Mining operations sales price per ton increased moderately due to mix changes resulting from ceasing operations at our Black Mesa and Seneca mines. Western U.S. Mining operations cost increases were driven by higher fuel costs, an increase in revenue-based royalties and production taxes, and the timing of major repairs. In addition, we experienced unfavorable geologic conditions and equipment issues related to the new longwall system at our Twentymile Mine; however, a recovery of certain costs associated with the equipment difficulties lessened the impact of these issues on our 2006 results. The Western U.S. Mining operations were also negatively impacted in 2006 by the cessation of operations at the Black Mesa mine in late 2005.

Eastern U.S. Mining operations Adjusted EBITDA increased $15.8 million, or 9.3%, compared to 2005 primarily due to higher volumes and sales prices, partially offset by higher costs per ton due to fuel costs, revenue-based royalties and production taxes as well as higher costs associated with equipment and geologic issues. The 2006 results were also negatively impacted by lower revenues from synthetic fuel facilities of $10.1 million as customers idled their synthetic fuel plants.

Our Australian Mining operations Adjusted EBITDA increased $75.8 million, or 37.4%, compared to 2005 primarily due to increased sales volumes following increased production from the second quarter installation of a new longwall system at our underground mine, higher metallurgical coal sales prices, and a $19.7 million contribution from our newly acquired mines.

Trading and Brokerage operations Adjusted EBITDA increased $49.5 million from 2005, as 2006 results included proceeds from restructuring the brokerage contract mentioned above, improved brokerage margins and contributions from the newly established international trading operation, partially offset by lower U.S. trading results.

Income From Continuing Operations Before Income Taxes and Minority Interests

	Year Ended December 31,		Increase (Decrease) to Income	
	2006	2005	$	%
	(Dollars in thousands)			
Total Segment Adjusted EBITDA	$ 1,028,638	$ 873,472	$ 155,166	17.8%
Corporate and Other Adjusted EBITDA	(127,682)	(165,623)	37,941	22.9%
Depreciation, depletion and amortization	(294,270)	(253,788)	(40,482)	(16.0)%
Asset retirement obligation expense	(15,830)	(20,329)	4,499	22.1%
Interest expense and early debt extinguishment costs	(139,064)	(98,066)	(40,998)	(41.8)%
Interest income	11,309	9,088	2,221	24.4%
Income from continuing operations before income taxes and minority interests	$ 463,101	$ 344,754	$ 118,347	34.3%

Income from continuing operations before income taxes and minority interests of $463.1 million for 2006 is $118.3 million, or 34.3%, higher than 2005 primarily due to improved segment Adjusted EBITDA as discussed above.

Corporate and Other Adjusted EBITDA results include selling and administrative expenses, equity income from our joint ventures, net gains on asset disposals or exchanges, costs associated with past mining obligations and revenues and expenses related to our other commercial activities such as coalbed methane, generation development, Btu Conversion and resource management. The $37.9 million improvement in Corporate and Other Adjusted EBITDA (net expense) in 2006 compared to 2005 includes the following:

Higher gains on asset disposals and exchanges of $9.1 million. The 2006 activity included a $39.2 million gain on an exchange with the Bureau of Land Management of approximately 63 million tons of leased coal reserves at our Caballo mining operation for approximately 46 million tons of coal reserves contiguous with our North Antelope Rochelle mining operation and other gains on asset disposals totaling $14.3 million. In comparison, activity in 2005 included a $31.1 million gain from the sale of our remaining 0.838 million units of Penn Virginia Resource Partners, L.P., a $12.5 million gain from the sale of non-strategic coal reserves and properties, and other gains on asset disposals of $0.8 million;

Higher equity income of $8.0 million from our 25.5% interest in Carbones del Guasare, which owns and operates the Paso Diablo Mine in Venezuela;

Lower selling and administrative expenses of $4.6 million primarily associated with lower performance-based incentive costs, partially offset by increases to share-based compensation expense as a result of the new requirement to expense stock options, costs to support corporate and international growth initiatives and costs for the development and installation of a new enterprise resource planning system. The lower costs associated with the performance-based incentive plan related to a long-term, executive incentive plan that is driven by shareholder return and reflected lower stock price appreciation in 2006 than in 2005; and

Lower net expenses of $4.7 million related to the development of the Prairie State Energy Campus due to a higher rate of cost reimbursement from the partners in 2006.

Depreciation, depletion and amortization increased $40.5 million in 2006 due to higher production volume, acquisitions and the impact of escalating capital costs and new capital, including two new longwall installations and new mine development. Also, 2005 depreciation, depletion and amortization was net of amortization of acquired contract liabilities.

Interest expense and early debt extinguishment costs increased $41.0 million primarily due to approximately $1.8 billion of debt issued or assumed in the second half of 2006 as part of the Excel acquisition. See Liquidity and Capital Resources for more details of the debt issued.

Net Income

	Year Ended December 31,		Increase (Decrease) to Income	
	2006	2005	$	%
	(Dollars in thousands)			
Income from continuing operations before income taxes and minority interests	$ 463,101	$ 344,754	$ 118,347	34.3%
Income tax benefit (provision)	90,084	(63,779)	153,863	241.2%
Minority interests	(611)	(2,472)	1,861	75.3%
Income from continuing operations	552,574	278,503	274,071	98.4%
Income from discontinued operations	48,123	144,150	(96,027)	(66.6)%
Net income	$ 600,697	$ 422,653	$ 178,044	42.1%

Income from continuing operations increased $274.1 million in 2006 compared to 2005 due to the increase in income from continuing operations before income taxes and minority interests discussed above and an income tax benefit compared to an income tax provision in 2005. The income tax benefit for the year ended 2006 related primarily to a reduction in tax reserves no longer required due to the finalization of various federal and state returns and expiration of applicable statute of limitations, and a reduction in a portion of the valuation allowance related to net operating loss (NOL) carry-forwards. The reduction to the valuation allowance resulted from an increase to estimated future taxable income primarily resulting from long-term contracts signed in late 2006 which increased our ability to realize these benefits in the future. Minority interests increased primarily as a result of acquiring an additional interest in a joint venture near the end of the first quarter of 2006.

Outlook

Events Impacting Near-Term Operations

Global coal markets continued to grow, driven by increased demand from growing and developing economies. The U.S. economy grew 2.2% for 2007 as reported by the U.S. Commerce Department, while China s economy grew 11.4% in 2007 as published by the National Bureau of Statistics of China.

Growing constraints of global coal supplies ignited U.S. coal export interests beginning in the third quarter of 2007. By the start of 2008, global supply challenges became even greater. Flooding in Queensland, Australia in early 2008 is estimated to reduce seaborne coal supplies by more than 10 million metric tons; China issued a temporary moratorium on 2008 coal exports to secure supply for domestic needs, and South Africa temporarily shutdown coal production destined for export markets to conserve energy while reestablishing sufficient domestic coal supply. As a result, U.S. coal products are realizing expanded market reach resulting in higher published prices for all products. We expect to capitalize on the strong global markets primarily through production and sales of metallurgical and thermal coal from our Australian operations as well as through our U.S. and international coal trading activities.

In Australia, we anticipate selling 23 to 25 million tons in 2008, as much as 17% higher than 2007 s level. Of our anticipated shipments, we have nine to 10 million tons of coal production available to be priced in 2008, approximately two-thirds of which is metallurgical coal. Our 2008 results will be affected by the final Australian coal

price settlements. Our two primary shipping points, Dalrymple Bay Coal Terminal and Port of Newcastle, continue to experience lengthy vessel queues, extreme weather conditions impacting operations and the coal logistics chain, and transportation challenges, which could result in delayed shipments and demurrage charges.

In the U.S., we anticipate higher volumes in 2008 versus 2007 from all the coal basins where we operate. Approximately 97% of our higher 2008 volumes are committed to existing customer contracts. In addition, the higher 2008 volume includes the mid-year startup of a new mine in the Southwestern U.S. Our 2008 results will be impacted to the extent we complete ramp-up activities on time and at expected capacity. Although we

currently expect to increase our shipment levels, our ability to reach targeted volumes is dependent upon the performance of the rail carriers.

We expect strong improvements in U.S. and Australia operating results from higher prices and increased volumes, partly offset by some of the factors discussed above and escalation of key supply costs including approximately $150 million in higher energy-related expenses and the effects of exchange rates.

Long-term Outlook

Our outlook for the coal markets remains positive. We believe strong coal markets will continue worldwide, as long as growth continues in the U.S., Asia and other industrialized economies that are increasing coal demand for electricity generation and steelmaking. More than 100 gigawatts of new coal-fueled electricity generating capacity is scheduled to come on line around the world between 2008 and 2010, and the EIA projects an additional 130 gigawatts of new U.S. coal-fueled generation by 2030, including 9 gigawatts at coal-to-liquids plants and 45 gigawatts at integrated gasification combined-cycle plants, which represents more than 500 million tons of additional coal demand.

Coal-to-gas (CTG) and coal-to-liquids (CTL) plants represent a significant avenue for long-term industry growth. The EIA continues to project an increase in demand for unconventional sources of transportation fuel, including CTL, and in the U.S. CTL technologies are receiving U.S. support from both political parties. China and India are developing CTG and CTL facilities.

Demand for Powder River Basin coal remains strong, particularly for our ultra-low sulfur products. The Powder River Basin represents more than half of our production. We control approximately 3.3 billion tons of proven and probable reserves in the Southern Powder River Basin, and we sold 139.8 million tons of coal from this region during 2007.

We are targeting 2008 production of 220 to 240 million tons and total sales volume of 240 to 260 million tons, both of which include 23 to 25 million tons from Australia. As of December 31, 2007, our unpriced volumes for 2008 planned production included nine to 10 million Australian tons, two-thirds of which is metallurgical coal, and five to seven million U.S. tons. Unpriced volumes for 2009 include 17 to 20 million Australian tons, approximately half of which is metallurgical coal, and 80 to 90 million U.S. tons.

Management plans to aggressively control costs and operating performance to mitigate external cost pressures, geologic conditions and potentially adverse port and rail performance. We are experiencing increases in operating costs related to fuel, explosives, steel, tires, contract mining and healthcare, and have taken measures to mitigate the increases in these costs, including a company-wide initiative to instill best practices at all operations. In addition, historically low long-term interest rates also have a negative impact on expenses related to our actuarially determined, employee-related liabilities. We may also encounter poor geologic conditions, lower third-party contract miner or brokerage source performance or unforeseen equipment problems that limit our ability to produce at forecasted levels. To the extent upward pressure on costs exceeds our ability to realize sales increases, or if we experience unanticipated operating or transportation difficulties, our operating margins would be negatively impacted. See Cautionary Notice Regarding Forward-Looking Statements and Item 1A. Risk Factors for additional considerations regarding our outlook.

Global climate change continues to attract considerable public and scientific attention. Enactment of laws and passage of regulations regarding greenhouse gas emissions by the United States or some of its states or by other countries, or other actions to limit carbon dioxide emissions, could result in electric generators switching from coal to other fuel sources. We continue to support clean coal technology development and voluntary initiatives addressing global climate change through our participation as a founding member of the FutureGen Alliance, through our commitment to the Australian COAL21 Fund, and through our participation in the Power Systems Development Facility, the

PowerTree Carbon Company LLC, and the Asia-Pacific Partnership for Clean Development and Climate. In addition, we are the only non-Chinese equity partner in GreenGen, the first near-zero emissions coal-fueled power plant with carbon capture and storage (CCS) which is under development in China.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Generally accepted accounting principles require that we make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. On an on-going basis, we evaluate our estimates. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

Employee-Related Liabilities

We have significant long-term liabilities for our employees postretirement benefit costs and defined benefit pension plans. Detailed information related to these liabilities is included in Notes 15 and 16 to our consolidated financial statements. The adoption of SFAS No. 158 on December 31, 2006 resulted in each of these liabilities recorded on the consolidated balance sheet as of December 31, 2006 being equal to the actuarially-determined funded status of the plans. Liabilities for postretirement benefit costs and workers compensation obligations are not funded. Our pension obligations are funded in accordance with the provisions of federal law. Expense for the year ended December 31, 2007 for the pension and postretirement liabilities totaled $102.2 million, while payments were $71.6 million.

Each of these liabilities are actuarially determined and we use various actuarial assumptions, including the discount rate and future cost trends, to estimate the costs and obligations for these items. Our discount rate is determined by utilizing a hypothetical bond portfolio model which approximates the future cash flows necessary to service our liabilities.

We make assumptions related to future trends for medical care costs in the estimates of retiree health care and work-related injuries and illnesses obligations. Our medical trend assumption is developed by annually examining the historical trend of our cost per claim data. In addition, we make assumptions related to future compensation increases and rates of return on plan assets in the estimates of pension obligations.

If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could differ materially from our current estimates. Moreover, regulatory changes could increase our obligation to satisfy these or additional obligations. Our most significant employee liability is postretirement health care, and assumed discount rates and health care cost trend rates have a significant effect on the expense and liability amounts reported for health care plans. Below we have provided two separate sensitivity analyses to demonstrate the significance of these assumptions in relation to reported amounts.

Health care cost trend rate:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in thousands)	
Effect on total service and interest cost components[1]	$ 11,202	$ (9,580)
Effect on total postretirement benefit obligation[1]	$ 81,535	$ (70,842)

Discount rate:

	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in thousands)	
Effect on total service and interest cost components[1]	$ 1,076	$ (1,913)
Effect on total postretirement benefit obligation[1]	$ (35,166)	$ 41,399
Total		

(1) In addition to the effect on total service and interest cost components of expense, changes in trend and discount rates would also increase or decrease the actuarial gain or loss amortization expense component. The gain or loss amortization would approximate the increase or decrease in the obligation divided by 8.92 years at December 31, 2007.

Asset Retirement Obligations

Our asset retirement obligations primarily consist of spending estimates for surface land reclamation and support facilities at both surface and underground mines in accordance with federal and state reclamation laws as defined by each mining permit. Asset retirement obligations are determined for each mine using various estimates and assumptions including, among other items, estimates of disturbed acreage as determined from engineering data, estimates of future costs to reclaim the disturbed acreage, the timing of these cash flows, and a credit-adjusted, risk-free rate. As changes in estimates occur (such as mine plan revisions, changes in estimated costs, or changes in timing of the reclamation activities), the obligation and asset are revised to reflect the new estimate after applying the appropriate credit-adjusted, risk-free rate. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could be materially different than currently estimated. Moreover, regulatory changes could increase our obligation to perform reclamation and mine closing activities. Asset retirement obligation expense for the year ended December 31, 2007, was $25.6 million, and payments totaled $10.2 million. See detailed information regarding our asset retirement obligations in Note 14 to our consolidated financial statements.

Income Taxes

We account for income taxes in accordance with SFAS No. 109, Accounting for Income Taxes (SFAS No. 109), which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. 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 our annual evaluation of the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in our annual evaluation of our valuation allowance, we may record a change in valuation allowance through income tax expense in the period such determination is made.

We establish reserves for tax contingencies when, despite the belief that our tax return positions are fully supported, certain positions are likely to be challenged and may not be fully sustained. The tax contingency reserves are analyzed on a quarterly basis and adjusted based upon changes in facts and circumstances, such as the progress of federal and state audits, case law and emerging legislation. Our effective tax rate includes the impact of tax contingency reserves

and changes to the reserves, including related interest. We establish the reserves based upon management s assessment of exposure associated with permanent tax differences (i.e. tax depletion expense, etc.) and certain tax sharing agreements. We are subject to federal audits for several open years due to our previous inclusion in multiple consolidated groups and the various parties involved in finalizing those years. Additional details regarding the effect of income taxes on our consolidated financial statements is available in Note 12.

Interpretation No. 48 Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN No. 48) prescribes a recognition threshold and measurement attribute for the

financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. We adopted this interpretation effective January 1, 2007.

Revenue Recognition

In general, we recognize revenues when they are realizable and earned. We generated 95% of our revenue in 2007 from the sale of coal to our customers. Revenue from coal sales is realized and earned when risk of loss passes to the customer. Coal sales are made to our customers under the terms of coal supply agreements, most of which are long-term (greater than one year). Under the typical terms of these coal supply agreements, title and risk of loss transfer to the customer at the mine or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s) that delivers coal to its destination.

With respect to other revenues, other operating income, or gains on asset sales 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.

Trading Activities

We engage in the buying and selling of coal, freight and emissions allowances, both in over-the-counter markets and on exchanges. Our coal trading contracts are accounted for on a fair value basis under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. To establish fair values for our trading contracts, we use bid/ask price quotations obtained from multiple, independent third-party brokers to value coal, freight and emission allowance positions from the over-the-counter market. Prices from these sources are then averaged to obtain trading position values. We could experience difficulty in valuing our market positions if the number of third-party brokers should decrease or market liquidity is reduced. Published settlement prices are used to value our exchange-based positions.

As of December 31, 2007, 97% of the contracts in our trading portfolio were valued utilizing prices from over-the-counter market sources, adjusted for coal quality and traded transportation differentials. As of December 31, 2007, 58% of the estimated future value of our trading portfolio was scheduled to be realized by the end of 2008 and 99% within 24 months. See Note 6 to our consolidated financial statements for additional details regarding assets and liabilities from our coal trading activities.

Exploration and Drilling Costs

Exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves.

Advance Stripping Costs

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

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

Business Combinations

We account for our business acquisitions under the purchase method of accounting consistent with the requirements of SFAS No. 141, Business Combinations. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management s judgment, and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates, asset lives, and market multiples, among other items.

Share-Based Compensation

We account for share-based compensation in accordance with the fair value recognition provisions of SFAS No. 123 (Revised 2004), Share-Based Payment (SFAS 123(R)), which we adopted using the modified prospective option on January 1, 2006. Under SFAS No. 123(R), share-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, nonqualified stock options, performance units, and an employee stock purchase plan as part of our share-based compensation program. Determining fair value requires us to make a number of assumptions, including items such as expected term, risk-free rate and expected volatility. The assumptions used in calculating the fair value of share-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.

Liquidity and Capital Resources

Our primary sources of cash include sales of our coal production to customers, cash generated from our trading and brokerage activities, sales of non-core assets and financing transactions, including sales of our accounts receivable through our securitization program. Our primary uses of cash include our cash costs of coal production, capital expenditures, interest costs and costs related to past mining obligations as well as planned acquisitions. Our ability to pay dividends, service our debt (interest and principal) and acquire new productive assets or businesses is dependent upon our ability to continue to generate cash from the primary sources noted above in excess of the primary uses. Future dividends, among other things, are subject to limitations imposed by our Senior Notes and Debenture covenants. We expect to fund all of our capital expenditure requirements with cash generated from operations.

Net cash provided by operating activities from continuing operations was $447.2 million for the year ended December 31, 2007, a decrease of $144.2 million compared to $591.4 million provided by operating activities from continuing operations in the prior year. The decrease was primarily related to lower profitability from our operations. Net cash used in operating activities of discontinued operations of $130.8 million was primarily used to fund the region s net operating loss and for cash costs of the spin-off.

Net cash used in investing activities from continuing operations was $541.7 million for the year ended December 31, 2007 compared to $2.06 billion used in the prior year. The decrease was primarily related to the acquisition of Excel of $1.51 billion, net of cash acquired, in 2006 and higher proceeds of $90.2 million from disposals of assets in 2007. Partially offsetting these items was higher capital spending of $72.9 million. Capital expenditures in 2007 included mine development at our recently acquired Australian mines, the completion of an in pit conveyor system, and coal blending and loadout facility at one of our Western U.S. mines and the purchase of coal reserves and surface lands in the Illinois Basin. Net cash used in investing activities of discontinued operations was $33.6 million and was used for pre-spin capital costs for Patriot.

Net cash provided by financing activities from continuing operations was $44.8 million during the year ended December 31, 2007, compared to $1.41 billion provided in 2006. During 2007, we repaid $37.9 million of our Term Loan and purchased in the open market $13.8 million face value of our 5.875% Senior Notes due 2016. We also made the final principal payment of $59.5 million on our 5% Subordinated Note. Our Revolving Credit Facility balance increased to $97.7 million as it was utilized to fund cash contributions to

Patriot at the spin-off. In 2006, we issued net borrowings of $1.74 billion, which we utilized to fund the $1.51 billion Excel acquisition, the repayment of Excel s bank facility and a portion of its outstanding bonds, and other corporate purposes. The net issuance of debt related to the Excel acquisition was partially offset in 2006 by repurchases of $7.7 million of our 5.875% Senior Notes in the open market, scheduled debt repayments of $11.1 million on our 5% Subordinated Note and other notes payable, and $99.8 million for the repurchase of common stock. Net cash used in financing activities of discontinued operations of $67.0 million was primarily cash provided to Patriot at spin-off to fund their working capital needs.

Our total indebtedness as of December 31, 2007 and 2006 consisted of the following:

	December 31,	
	2007	2006
	(Dollars in thousands)	
Term Loan under Senior Unsecured Credit Facility	$ 509,084	$ 547,000
Revolving Credit Facility	97,700	
Convertible Junior Subordinated Debentures due 2066	732,500	732,500
7.375% Senior Notes due 2016	650,000	650,000
6.875% Senior Notes due 2013	650,000	650,000
7.875% Senior Notes due 2026	246,965	246,897
5.875% Senior Notes due 2016	218,090	231,845
5.0% Subordinated Note		59,504
6.84% Series C Bonds due 2016	43,000	43,000
6.34% Series B Bonds due 2014	21,000	21,000
6.84% Series A Bonds due 2014	10,000	10,000
Capital lease obligations	92,186	96,869
Fair value of interest rate swaps	1,604	(13,784)
Other	971	2,201
Total	$ 3,273,100	$ 3,277,032

Senior Unsecured Credit Facility

In September 2006, we entered into a Third Amended and Restated Credit Agreement, which established a $2.75 billion Senior Unsecured Credit Facility and which amended and restated in full our then existing $1.35 billion Senior Secured Credit Facility. The Senior Unsecured Credit Facility provides a $1.8 billion Revolving Credit Facility and a $950.0 million Term Loan Facility. The Revolving Credit Facility is intended to accommodate working capital needs, letters of credit, the funding of capital expenditures and other general corporate purposes. The Revolving Credit Facility also includes a $50.0 million sub-facility available for same-day swingline loan borrowings.

The Term Loan Facility, which was fully drawn in October 2006 in connection with the Excel acquisition was paid down in December 2006 ($403.0 million), from a portion of the net proceeds from the Debentures. In conjunction with the establishment of the Senior Unsecured Credit Facility, we incurred $8.6 million in financing costs, of which $5.6 million related to the Revolving Credit Facility and $3.0 million related to the Term Loan Facility. These debt issuance costs will be amortized to interest expense over five years, the term of the Senior Unsecured Credit Facility.

Loans under the facility are available in U.S. dollars, with a sub-facility under the Revolving Credit Facility available in Australian dollars, pounds sterling and Euros. Letters of credit under the Revolving Credit Facility are available to us in U.S. dollars with a sub-facility available in Australian dollars, pounds sterling and Euros. The interest rate payable on the Revolving Credit Facility and the Term Loan Facility under the Senior Unsecured Credit Facility is based on a pricing grid tied to our leverage ratio, as defined in the Third

Amended and Restated Credit Agreement. Currently, the interest rate payable on the Revolving Credit Facility and the Term Loan Facility is LIBOR plus 0.75%, which at December 31, 2007 was 5.4%.

Under the Senior Unsecured Credit Facility, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio, as defined in the Third Amended and Restated Credit Agreement. The financial covenants also place limitations on our investments in joint ventures, unrestricted subsidiaries, indebtedness of non-loan parties, and the imposition of liens on our assets. The new facility is less restrictive with respect to limitations on our dividend payments, capital expenditures, asset sales or stock repurchases. The Senior Unsecured Credit Facility matures on September 15, 2011.

As of December 31, 2007, we had $97.7 million borrowings and $413.5 million letters of credit outstanding under our Revolving Credit Facility. Our Revolving Credit Facility is primarily used for standby letters of credit and short-term working capital needs. The remaining available borrowing capacity ($1.29 billion as of December 31, 2007) can be used to fund strategic acquisitions or meet other financing needs, including additional standby letters of credit. We were in compliance with all of the covenants of the Senior Unsecured Credit Facility, the 6.875% Senior Notes, the 5.875% Senior Notes, the 7.375% Senior Notes, the 7.875% Senior Notes and the Convertible Junior Subordinated Debentures as of December 31, 2007.

Convertible Junior Subordinated Debentures

On December 20, 2006, we issued $732.5 million aggregate principal amount of 4.75% Convertible Junior Subordinated Debentures due 2066 (the Debentures). Net proceeds from the offering, after deducting underwriting discounts and offering expenses, were $715.0 million and were used to repay indebtedness under our Senior Unsecured Credit Facility. The Debentures pay interest semiannually at a rate of 4.75% per year. We may elect to, and if and to the extent that a mandatory trigger event (as defined in the indenture governing the Debentures) has occurred and is continuing will be required to, defer interest payments on the Debentures. After five years of deferral at our option, or upon the occurrence of a mandatory trigger event, we generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay deferred interest, subject to certain limitations. In no event may we defer payments of interest on the Debentures for more than 10 years.

The Debentures are convertible at any time on or prior to December 15, 2036 if any of the following conditions occur: (i) our closing common stock price exceeds 140% of the then applicable conversion price for the Debentures (currently $81.83 per share) for at least 20 of the final 30 trading days in any quarter; (ii) a notice of redemption is issued with respect to the Debentures; (iii) a change of control, as defined in the indenture governing the Debentures; (iv) satisfaction of certain trading price conditions; and (v) other specified corporate transactions described in the indenture governing the Debentures. In addition, the Debentures are convertible at any time after December 15, 2036 to December 15, 2041, the scheduled maturity date. In the case of conversion following a notice of redemption or upon a non-stock change of control, as defined in the indenture governing the Debentures, holders may convert their Debentures into cash in the amount of the principal amount of their Debentures and shares of our common stock for any conversion value in excess of the principal amount. In all other conversion circumstances, holders will receive perpetual preferred stock (see Note 17 to our consolidated financial statements) with a liquidation preference equal to the principal amount of their Debentures, and any conversion value in excess of the principal amount will be settled with our common stock. As a result of the Patriot spin-off, the conversion rate was adjusted to 17.1078 shares of common stock per $1,000 principal amount of Debentures effective November 23, 2007. This adjusted conversion rate represents a conversion price of approximately $58.45.

The Debentures are unsecured obligations, ranking junior to all existing and future senior and subordinated debt (excluding trade accounts payable or accrued liabilities arising in the ordinary course of business) except for any future debt that ranks equal to or junior to the Debentures. The Debentures will rank equal in right of payment with

our obligations to trade creditors. Substantially, all of our existing indebtedness is senior to the Debentures. In addition, the Debentures will be effectively subordinated to all indebtedness of

our subsidiaries. The indenture governing the Debentures places no limitation on the amount of additional indebtedness that we or any of our subsidiaries may incur (see Note 13 to our consolidated financial statements for additional information on the Debentures).

7.375% Senior Notes Due November 2016 and 7.875% Senior Notes Due November 2026

On October 12, 2006, we completed a $650.0 million offering of 7.375% 10-year Senior Notes due 2016 and $250 million of 7.875% 20-year Senior Notes due 2026. The notes are general unsecured obligations and rank senior in right of payment to any subordinated indebtedness; equally in right of payment with any senior indebtedness; effectively junior in right of payment to our existing and future secured indebtedness, to the extent of the value of the collateral securing that indebtedness; and effectively junior to all the indebtedness and other liabilities of our subsidiaries that do not guarantee the notes. Interest payments are scheduled to occur on May 1 and November 1 of each year, and commenced on May 1, 2007.

The notes are guaranteed by our Subsidiary Guarantors, as defined in the note indenture. The note indenture contains covenants that, among other things, limit our ability to create liens and enter into sale and lease-back transactions. The notes are redeemable at a redemption price equal to 100% of the principal amount of the notes being redeemed plus a make-whole premium, if applicable, and any accrued unpaid interest to the redemption date. Net proceeds from the offering, after deducting underwriting discounts and expenses, were $886.1 million.

6.875% Senior Notes Due March 2013

On March 21, 2003, we issued $650.0 million of 6.875% Senior Notes due March 2013. The notes are senior unsecured obligations and rank equally with all of our other senior unsecured indebtedness. Interest payments are scheduled to occur on March 15 and September 15 of each year. The notes are guaranteed by our Subsidiary Guarantors as defined in the note indenture. The note indenture contains covenants which, among other things, limit our ability to incur additional indebtedness and issue preferred stock, pay dividends or make other distributions, make other restricted payments and investments, create liens, sell assets and merge or consolidate with other entities. The notes are redeemable prior to March 15, 2008, at a redemption price equal to 100% of the principal amount plus a make-whole premium (as defined in the indenture) and on or after March 15, 2008, at fixed redemption prices as set forth in the indenture.

5.875% Senior Notes Due March 2016

On March 23, 2004, we completed an offering of $250.0 million of 5.875% Senior Notes due March 2016. The notes are senior unsecured obligations and rank equally with all of our other senior unsecured indebtedness. Interest payments are scheduled to occur on April 15 and October 15 of each year, and commenced on April 15, 2004. The notes are guaranteed by our Subsidiary Guarantors as defined in the note indenture. The note indenture contains covenants which, among other things, limit our ability to incur additional indebtedness and issue preferred stock, pay dividends or make other distributions, make other restricted payments and investments, create liens, sell assets and merge or consolidate with other entities. The notes are redeemable prior to April 15, 2009, at a redemption price equal to 100% of the principal amount plus a make-whole premium (as defined in the indenture) and on or after April 15, 2009, at fixed redemption prices as set forth in the indenture. Net proceeds from the offering, after deducting underwriting discounts and expenses, were $244.7 million.

Series Bonds

As of December 31, 2007, we had $74.0 million in Series Bonds outstanding, which were assumed as part of the Excel acquisition. The 6.84% Series A Bonds have a balloon maturity in December 2014. The 6.34% Series B Bonds

mature in December 2014 and are payable in installments beginning December 2008. The 6.84% Series C Bonds mature in December 2016 and are payable in installments beginning December 2012. Interest payments are scheduled to occur in June and December of each year.

Interest Rate Swaps

As of December 31, 2007, we had entered into a series of fixed-to-floating interest rate swaps with a notional principal amount of $120.0 million. Under the terms of these swaps we receive a fixed rate of 6.875% and pay a weighted average floating rate of LIBOR plus 2.0%, which resets each March 15, June 15, September 15 and December 15. The swaps have been designated as a hedge of the changes in the fair value of the 6.875% Senior Notes due 2013.

We have also entered into another series of fixed-to-floating interest rate swaps with a notional principal amount of $100.0 million. Under the terms of these swaps we receive a fixed rate of 5.875% and pay a weighted average floating rate of LIBOR plus 0.25%, which resets each April 15 and October 15. This series of swaps has been designated as a hedge of the changes in the fair value of the 5.875% Senior Notes due 2016.

In conjunction with the Term Loan Facility, we have a floating-to-fixed interest rate swap in place for a notional principal amount of $120.0 million. Under the terms of this swap we receive a floating rate of LIBOR plus 1.0% and pay a fixed rate of 6.25%. This interest rate swap was designated as a hedge of the variable interest payments on the Term Loan under the Senior Unsecured Credit Facility.

Because the critical terms of the swaps and the respective debt instruments they hedge coincide, there was no hedge ineffectiveness recognized in the consolidated statements of operations during the years ended December 31, 2007 and 2006. At December 31, 2007 and 2006 there was an unrealized loss related to the cash flow hedge of $6.8 million and $2.5 million, respectively. At December 31, 2007, there was a net unrealized gain on the fair value hedges of $1.6 million. At December 31, 2006, the net unrealized loss on the fair value hedges was $13.8 million. The fair value hedge is reflected as an adjustment to the carrying value of the Senior Notes (see table above).

Third-party Security Ratings

The ratings for our Senior Unsecured Credit Facility and our Senior Unsecured Notes are as follows: Moody s has issued a Ba1 rating, Standard & Poor s a BB rating and Fitch has issued a BB+ rating. The ratings on our Convertible Junior Subordinated Debentures are as follows: Moody s has issued a Ba3 rating, Standard & Poor s a B rating and Fitch has issued a BB- rating. These security ratings reflected the views of the rating agency only. An explanation of the significance of these ratings may be obtained from the rating agency. Such ratings are not a recommendation to buy, sell or hold securities, but rather an indication of creditworthiness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Shelf Registration Statement

On July 28, 2006, we filed an automatic shelf registration statement on Form S-3 as a well-known seasoned issuer with the SEC. The registration was for an indeterminate number of securities and is effective for three years, at which time we can file an automatic shelf registration statement that would become immediately effective for another three-year term. Under this universal shelf registration statement, we have the capacity to offer and sell from time to time securities, including common stock, preferred stock, debt securities, warrants and units. The Debentures, 7.375% Senior Notes due 2016 and 7.875% Senior Notes due 2026 were issued pursuant to the shelf registration statement.

Excel Transaction

In October 2006, we acquired Excel Coal Limited (Excel) for US$1.54 billion in cash plus assumed debt of US$293.0 million, less US$30.0 million of cash acquired in the transaction. This acquisition was financed with

borrowings under our Senior Unsecured Credit Facility and Senior Notes due 2016 and 2026 (see Note 13 of our consolidated financial statements for additional information on the financing of the Excel acquisition). The Excel acquisition included three operating mines and three development-stage mines (all of which are

operating as of December 31, 2007), with up to 500 million tons of proven and probable coal reserves. The results of operations of Excel are included in our Australian Mining Operations segment from October 2006. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, Business Combinations (see Note 5 of our consolidated financial statements for additional information on the Excel acquisition).

Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2007:

		Payments Due By Year			
	Total	Less than 1 Year	2-3 Years	4-5 Years	More than 5 Years
	(Dollars in thousands)				
Long-term debt obligations (principal and interest)	$ 5,781,312	$ 344,324	$ 471,852	$ 825,632	$ 4,139,504
Capital lease obligations (principal and interest)	116,861	17,349	34,258	30,234	35,020
Operating lease obligations	359,045	85,356	120,218	71,759	81,712
Unconditional purchase obligations[1]	168,923	168,923			
Coal reserve lease and royalty obligations	383,416	187,946	139,564	12,777	43,129
Other long-term liabilities[2]	1,302,039	112,418	215,443	210,275	763,903
Total contractual cash obligations	$ 8,111,596	$ 916,316	$ 981,335	$ 1,150,677	$ 5,063,268

(1) We have purchase agreements with approved vendors for most types of operating expenses. However, our specific open purchase orders (which have not been recognized as a liability) under these purchase agreements, combined with any other open purchase orders, are not material. The commitments in the table above relate to significant capital purchases.

(2) Represents long-term liabilities relating to our postretirement benefit plans, work-related injuries and illnesses, defined benefit pension plans and mine reclamation and end of mine closure costs.

As of December 31, 2007, we had $67.8 million of purchase obligations for capital expenditures and $301.6 million of obligations related to federal coal reserve lease payments due over the next three years. Total capital expenditures for 2008 are expected to range from $350 million to $400 million, excluding federal coal reserve lease payments, and relate to replacement, improvement, or expansion of existing mines, particularly in Australia, the El Segundo mine development in New Mexico, and growth initiatives such as increasing capacity in the Powder River Basin. Capital expenditures were funded primarily through operating cash flow.

Our subsidiary, Peabody Pacific, has committed to pay up to a maximum of A$0.20/tonne (approximately US$0.15/tonne) of coal sales for a period of five years to the Australian COAL21 Fund. The COAL21 Fund is a voluntary coal industry fund to support clean coal technology demonstration projects and research in Australia. All major coal companies in Australia have committed to this fund. The commitment to pay started on April 1, 2007 with

a levy of A$0.10/tonne of coal sales. This levy rose to A$0.20/tonne on July 1, 2007.

We do not expect any of the $152.6 million of gross unrecognized tax benefits reported in our consolidated financial statements to require cash settlement within the next year. Beyond that, we are unable to make reasonably reliable estimates of periodic cash settlements with respect to such unrecognized tax benefits.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include guarantees, indemnifications, financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds and our accounts receivable securitization. Liabilities related to these arrangements are not 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.

We use a combination of surety bonds, corporate guarantees (i.e. self bonds) and letters of credit to secure our financial obligations for reclamation, workers compensation, postretirement benefits and coal lease obligations as follows as of December 31, 2007:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Retiree Healthcare Obligations	Other[1]	Total
	(Dollars in millions)					
Self Bonding	$ 640.6	$	$	$	$	$ 640.6
Surety Bonds	418.3	73.0	31.2		16.7	539.2
Letters of Credit	1.6		102.7	41.4	267.9	413.6
	$ 1,060.5	$ 73.0	$ 133.9	$ 41.4	$ 284.6	$ 1,593.4

(1) Includes financial guarantees primarily related to joint venture debt, the PBGC and collateral for surety companies.

As part of arrangements through which we obtain exclusive sales representation agreements with small coal mining companies (the Counterparties), we issued financial guarantees on behalf of the Counterparties. These guarantees facilitate the Counterparties efforts to obtain bonding or financing. In 2007, we purchased approximately 345 million tons of coal reserves and surface lands in the Illinois Basin. In conjunction with this purchase, we agreed to provide up to $64.8 million of reclamation and bonding commitments to a third-party coal company. We have recognized the full amount of these commitments as a liability as of December 31, 2007. The non-cash portion of this transaction was excluded from the investing section of the statement of cash flows.

In the event of default, the terms of our guarantees provide for multiple recourse options, including the ability to assume the loans and procure title and use of the equipment purchased through the loans. If default occurs, we have the ability and intent to exercise our recourse options, so the liability associated with the guarantee has been valued at zero. The aggregate amount guaranteed for all such Counterparties was $8.8 million at December 31, 2007. See Note 20 to our consolidated financial statements included in this report for a discussion of our guarantees.

As part of the Patriot spin-off, we agreed to maintain in force several letters of credit that secured Patriot obligations for certain employee benefits and workers compensation obligations. These letters of credit are to be released upon Patriot satisfying the beneficiaries with alternate letters of credit or insurance, which is expected to occur in 2008. If Patriot is unable to satisfy the primary beneficiaries by June 30, 2011, they are then required to provide directly to us a letter of credit in the amount of the remaining obligation. As of December 31, 2007, the amount of letters of credit securing Patriot obligations was $136.8 million.

Under our accounts receivable securitization program, undivided interests in a pool of eligible trade receivables contributed to our wholly-owned, bankruptcy-remote subsidiary are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit (Conduit). Purchases by the Conduit are financed with the sale of highly rated commercial paper. We utilize proceeds from the sale of our accounts receivable as an alternative to other forms of debt, effectively reducing our overall borrowing costs. The funding cost of the securitization program was $11.2 million and $1.9 million for the years ended December 31, 2007 and 2006, respectively. The securitization program is scheduled to expire in September 2009. The securitization transactions have been recorded as sales, with those accounts receivable sold to the Conduit removed from the

consolidated balance sheets. The amount of undivided interests in accounts receivable sold to the Conduit was $275.0 million and $219.2 million as of December 31, 2007 and 2006, respectively (see Note 7 to our consolidated financial statements for additional information on accounts receivable securitization).

The following is a summary of specified types of commercial commitments available to us as of December 31, 2007:

		Expiration Per Year			
	Total Amounts Committed	Within 1 Year	2-3 Years	4-5 Years	Over 5 Years
		(Dollars in thousands)			
Lines of credit and/or standby letters of credit	$ 1,800,000	$	$	$ 1,800,000	$

Newly Adopted Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN No. 48). This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

We adopted the provisions of FIN No. 48 on January 1, 2007, and as a result, reported $135.0 million of net unrecognized tax benefits ($144.0 million gross) in our consolidated financial statements. Due to the valuation allowance recorded against our deferred tax asset for NOL carryforwards as of January 1, 2007, none of the $135.0 million required an adjustment to retained earnings upon adoption.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS No. 158). For fiscal years ending after December 15, 2006, SFAS No. 158 required recognition of the funded status of pension and other postretirement benefit plans (an asset for overfunded status or a liability for underfunded status) in a company s balance sheet. In addition, the standard required recognition of actuarial gains and losses, prior service cost, and any remaining transition amounts from the initial application of SFAS No. 87, Employers Accounting for Pensions (SFAS No. 87) and SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions (SFAS No. 106) when determining a plan s funded status, with a corresponding charge to accumulated other comprehensive income (loss).

We adopted SFAS No. 158 on December 31, 2006, and as a result, recorded a noncurrent liability of $376.1 million, which reflected the total underfunded status of the pension, retiree healthcare and workers compensation plans. The funded status of each plan was measured as the difference between the fair value of the assets and the projected benefit obligation (the funded status). SFAS No. 158 did not impact net income.

Accounting Pronouncements Not Yet Implemented

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements, and therefore does not require any new fair value

measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 (January 1, 2008 for the Company). In February 2008, the FASB amended SFAS No. 157 to exclude leasing transactions and to delay the effective date by one year for nonfinancial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. We are in the process of determining the effect, if any, the adoption of SFAS No. 157 will have on our financial statements.

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 all entities with an option to report selected financial assets and liabilities at fair value. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007 (January 1, 2008 for the Company). We are in the process of determining the effect, if any, the adoption of SFAS No. 159 will have on our financial statements.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 establishes accounting and reporting standards for (1) noncontrolling interests in partially owned consolidated subsidiaries and (2) the loss of control of subsidiaries. SFAS No. 160 requires noncontrolling interests (minority interests) to be reported as a separate component of equity. The amount of net income attributable to the noncontrolling interest will be included in consolidated net income on the face of the income statement. In addition, this statement requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. Such gain or loss will be measured using the fair value of the noncontrolling equity investment on the deconsolidation date. SFAS No. 160 also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 (January 1, 2009 for the Company). Early adoption is not allowed. We are in the process of determining the effect the adoption of SFAS No. 160 will have on our financial statements.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which replaces SFAS No. 141. SFAS No. 141(R) significantly changes the principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. This statement also provides guidance for the recognition and measurement of goodwill acquired in a business combination and for determination of required disclosures that will enable users of the financial statements to evaluate the nature and financial effects of the business combination. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 (January 1, 2009 for the Company). We are in the process of determining the effect, if any, the adoption of SFAS No. 141(R) will have on our financial statements.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk.***

The potential for changes in the market value of our coal, freight and emissions allowance trading, fuel, explosives, interest rate and currency portfolios is referred to as market risk. Market risk related to our coal, freight and emissions allowance trading portfolio is evaluated using a value at risk analysis (described below). Value at risk analysis is not used to evaluate our non-trading fuel, explosives, interest rate and currency portfolios. A description of each market risk category is set forth below. We attempt to manage market risks through diversification, controlling position sizes and executing hedging strategies. Due to lack of quoted market prices and the long-term, illiquid nature of the positions, we have not quantified market risk related to our non-trading, long-term coal supply agreement portfolio.

Coal Trading Activities and Related Commodity Price Risk

We engage in over-the-counter, exchange-based and direct trading of coal, freight and emission allowances (collectively coal trading). These activities give rise to commodity price risk, which represents the potential loss that can be caused by an adverse change in the market value of a particular commitment. We actively measure, monitor and adjust traded position levels to remain within risk limits prescribed by management. For example, we have policies in place that limit the amount of total exposure, in value at risk terms, that we may assume at any point in time.

We account for coal trading using the fair value method, which requires us to reflect financial instruments with third parties, such as forwards, options and swaps, at market value in our consolidated financial statements. Our trading

portfolio included forwards and swaps as of December 31, 2007 and 2006.

We perform a value at risk analysis on our coal trading portfolio. The use of value at risk allows us to quantify in dollars, on a daily basis, the price risk inherent in our trading portfolio. Value at risk represents the

potential loss in value of our mark-to-market portfolio due to adverse market movements over a defined time horizon (liquidation period) within a specified confidence level. Our value at risk model is based on the industry standard variance/co-variance approach. This captures our exposure related to both swaps and forward positions. Our value at risk model assumes 5 and 15 day holding periods, as applicable, and a 95% one-tailed confidence interval. This means that there is a one in 20 statistical chance that the portfolio would lose more than the value at risk estimates during the liquidation period.

The use of value at risk allows management to aggregate pricing risks across products in the portfolio, compare risk on a consistent basis and identify the drivers of risk. Due to the subjectivity in the choice of the liquidation period, reliance on historical data to calibrate the models and the inherent limitations in the value at risk methodology, we perform regular stress and scenario analysis to estimate the impacts of market changes on the value of the portfolio. Additionally, back-testing is regularly performed to monitor the effectiveness of our value at risk measure. The results of these analyses are used to supplement the value at risk methodology and identify additional market-related risks.

We use historical data to estimate our value at risk and to better reflect current asset and liability volatilities. Given our reliance on historical data, value at risk is effective in estimating risk exposures in markets in which there are not sudden fundamental changes or shifts in market conditions. An inherent limitation of value at risk is that past changes in market risk factors may not produce accurate predictions of future market risk. Value at risk should be evaluated in light of this limitation.

During the year ended December 31, 2007, the combined actual low, high, and average values at risk for our coal trading portfolio were $1.2 million, $13.7 million, and $6.8 million, respectively. Our value at risk increased over the prior year due to greater price volatility in the coal markets, particularly in the international markets into which we have recently expanded. As of December 31, 2007, the timing of the estimated future realization of the value of our trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio
2008	58%
2009	41%
2010	0%
2011	1%
	100%

We also monitor other types of risk associated with our coal trading activities, including credit, market liquidity and counterparty nonperformance.

Credit Risk

Our concentration of credit risk is substantially with energy producers and marketers and electric utilities. Our policy is to independently evaluate each customer s creditworthiness prior to entering into transactions and to constantly monitor the credit extended. If we engage in a transaction with a counterparty that does not meet our credit standards, we will protect our position by requiring the counterparty to provide appropriate credit enhancement. In general, increases in coal price volatility and our own trading activity resulted in greater exposure to our coal-trading counterparties during the year. When appropriate (as determined by our credit management function), we have taken

steps to reduce our credit exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk of failure to perform under their contractual obligations. These steps include obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for our benefit to serve as collateral in the event of a failure to pay. To reduce our credit exposure related to trading and brokerage activities, we seek to enter into netting agreements with counterparties that permit us to offset receivables and payables with such counterparties. Counterparty risk with respect to interest rate swap and foreign currency forwards and options transactions is not considered to be significant based upon the creditworthiness of the participating financial institutions.

Foreign Currency Risk

We utilize currency forwards to hedge currency risk associated with anticipated Australian dollar expenditures. Our currency hedging program for 2008 targets hedging at least approximately 70% of our anticipated, non-capital Australian dollar-denominated expenditures. As of December 31, 2007, we had in place forward contracts designated as cash flow hedges with notional amounts outstanding totaling A$2.03 billion of which A$1.08 billion, A$556.7 million, and A$388.8 million will expire in 2008, 2009, and 2010, respectively. The accounting for these derivatives is discussed in Note 3 to our consolidated financial statements. Assuming we had no hedges in place, our exposure in Operating costs and expenses due to a $0.01 change in the Australian dollar/U.S. dollar exchange rate is approximately $12 million for 2008. However, taking into consideration hedges currently in place, our net exposure to the same rate change is approximately $1.6 million in 2008.

Interest Rate Risk

Our objectives in managing exposure to interest rate changes are to limit the impact of interest rate changes on earnings and cash flows and to lower overall borrowing costs. To achieve these objectives, we manage fixed-rate debt as a percent of net debt through the use of various hedging instruments, which are discussed in detail in Note 13 to our consolidated financial statements. As of December 31, 2007, after taking into consideration the effects of interest rate swaps, we had $2.57 billion of fixed-rate borrowings and $707.2 million of variable-rate borrowings outstanding. A one percentage point increase in interest rates would result in an annualized increase to interest expense of $7.1 million on our variable-rate borrowings. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a $0.3 million decrease in the estimated fair value of these borrowings.

Other Non-trading Activities

We manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements, rather than through the use of derivative instruments. We sold 94% and 90% of our sales volume under long-term coal supply agreements during 2007 and 2006, respectively. As of December 31, 2007, we had 5 to 10 million tons of expected U.S. production unpriced for 2008. We had 9 to 10 million tons remaining to be priced for 2008 in Australia at December 31, 2007. We have approximately 80 to 90 million tons of expected U.S. production unpriced for 2009, with an additional 17 to 20 million tons of expected Australia coal production unpriced for 2009.

Some of the products used in our mining activities, such as diesel fuel and explosives, are subject to commodity price risk. To manage this risk, we use a combination of forward contracts with our suppliers and financial derivative contracts, primarily swap contracts with financial institutions. As of December 31, 2007, we had derivative contracts outstanding that are designated as cash flow hedges of anticipated purchases of fuel and explosives.

Notional amounts outstanding under fuel-related, derivative swap contracts were 114.8 million gallons of crude oil scheduled to expire through 2010. We expect to consume 125 to 130 million gallons of fuel next year. A one dollar per barrel change in the price of crude oil would increase or decrease our annual fuel costs (ignoring the effects of hedging) by approximately $2.4 million.

Notional amounts outstanding under explosives-related swap contracts, scheduled to expire through 2010, were 5.7 mmbtu of natural gas. We expect to consume 315,000 to 325,000 tons of explosives per year. Through our natural gas hedge contracts, we have fixed prices for approximately 49% of our anticipated explosives requirements for 2008. Based on our expected usage, a change in natural gas prices of ten cents per mmbtu (ignoring the effects of hedging) would result in an increase or decrease in our operating costs of approximately $0.6 million per year.

Item 8. ***Financial Statements and Supplementary Data.***

See Part IV, Item 15 of this report for information required by this Item.

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

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Annual Report on Form 10-K, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures, as defined in Rule 13a-15 under the Securities Act of 1934, were effective.

Changes in Internal Control Over Financial Reporting

We periodically review our internal control over financial reporting as part of our efforts to ensure compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. In addition, we routinely review our system of internal control over financial reporting to identify potential changes to our processes and systems that may improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new systems, consolidating the activities of acquired business units, migrating certain processes to our shared services organizations, formalizing and refining policies and procedures, improving segregation of duties, and adding additional monitoring controls. In addition, when we acquire new businesses, we incorporate our controls and procedures into the acquired business as part of our integration activities. There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 U.S. generally accepted accounting principles.

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.

Management conducted an assessment of the effectiveness of our internal control over financial reporting using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Based on this assessment, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2007.

Our Independent Registered Public Accounting Firm, Ernst & Young LLP, has audited our internal control over financial reporting, as stated in their unqualified opinion report included herein.

/s/ GREGORY H. BOYCE /s/ RICHARD A. NAVARRE

Gregory H. Boyce
Chairman and Chief Executive Officer

Richard A. NavarrePresident, Chief Commercial Officer and
Chief Financial Officer

February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited Peabody Energy Corporation s (the Company s) internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Peabody Energy Corporation 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 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

In our opinion, Peabody Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007 based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Peabody Energy Corporation as of December 31, 2007 and 2006, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007, and our report dated February 27, 2008, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri

February 27, 2008

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

The information required by Item 401 of Regulation S-K is included under the caption Election of Directors in our 2008 Proxy Statement and in Part I of this report under the caption Executive Officers of the Company. The information required by Items 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions Ownership of Company Securities Section 16(a) Beneficial Ownership Reporting Compliance, Corporate Governance Matters and Information Regarding Board of Directors and Committees in our 2008 Proxy Statement. Such information is incorporated herein by reference.

Item 11. ***Executive Compensation.***

The information required by Items 402 and 407 (e)(4) and (e)(5) of Regulation S-K is included under the captions Executive Compensation, Compensation Committee Interlocks and Insider Participation and Report of the Compensation Committee in our 2008 Proxy Statement and is incorporated herein by reference.

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

The information required by Item 403 of Regulation S-K is included under the caption Ownership of Company Securities in our 2008 Proxy Statement and is incorporated herein by reference.

Equity Compensation Plan Information

As required by Item 201(d) of Regulation S-K, the following table provides information regarding our equity compensation plans as of December 31, 2007:

Plan Category	(a) Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	6,424,945	$ 9.32	13,554,993
Equity compensation plans not approved by security holders			

Total	6,424,945	$	9.32	13,554,993

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

The information required by Items 404 and 407(a) of Regulation S-K is included under the captions Certain Transactions and Relationships and Information Regarding Board of Directors and Committees in our 2008 Proxy Statement and is incorporated herein by reference.

Item 14. ***Principal Accounting Fees and Services.***

The information required by Item 9(e) of Schedule 14A is included under the caption Appointment of Independent Registered Public Accounting Firm and Fees in our 2008 Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules.***

(a) Documents Filed as Part of the Report

(1) Financial Statements.

The following consolidated financial statements of Peabody Energy Corporation are included herein on the pages indicated:

	Page
Report of Independent Registered Public Accounting Firm	F-1
Consolidated Statements of Operations - Years Ended December 31, 2007, 2006 and 2005	F-2
Consolidated Balance Sheets December 31, 2007 and December 31, 2006	F-3
Consolidated Statements of Cash Flows Years Ended December 31, 2007, 2006 and 2005	F-4
Consolidated Statements of Changes in Stockholders Equity - Years Ended December 31, 2007, 2006 and 2005	F-5
Notes to Consolidated Financial Statements	F-6

(2) Financial Statement Schedule.

The following financial statement schedule of Peabody Energy Corporation and the report thereon of the independent registered public accounting firm are at the pages indicated:

	Page
Report of Independent Registered Public Accounting Firm on Financial Statement Schedule	F-67
Valuation and Qualifying Accounts	F-68

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable and, therefore, have been omitted.

(3) Exhibits.

See Exhibit Index hereto.

Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the company and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the company and its subsidiaries on a consolidated basis. A copy of such instrument will be furnished to the Commission upon request.

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.

PEABODY ENERGY CORPORATION

/s/ GREGORY H. BOYCE

Gregory H. Boyce
Chairman and Chief Executive Officer

Date: February 27, 2008

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

Signature	Title	Date
/s/ GREGORY H. BOYCE Gregory H. Boyce	Chairman and Chief Executive Officer, Director (principal executive officer)	February 27, 2008
/s/ RICHARD A. NAVARRE Richard A. Navarre	President, Chief Commercial Officer and Chief Financial Officer (principal financial and accounting officer)	February 27, 2008
/s/ WILLIAM A. COLEY William A. Coley	Director	February 27, 2008
/s/ HENRY GIVENS, JR., PhD Henry Givens, Jr., PhD	Director	February 27, 2008
/s/ WILLIAM E. JAMES William E. James	Director	February 27, 2008
/s/ ROBERT B. KARN III Robert B. Karn III	Director	February 27, 2008
/s/ HENRY E. LENTZ Henry E. Lentz	Director	February 27, 2008
/s/ WILLIAM C. RUSNACK	Director	February 27, 2008

William C. Rusnack

/s/ JAMES R. SCHLESINGER, PhD	Director	February 27, 2008

James R. Schlesinger, PhD

Signature	Title	Date
/s/ BLANCHE M. TOUHILL, PhD	Director	February 27, 2008
Blanche M. Touhill, PhD		
/s/ JOHN F. TURNER	Director	February 27, 2008
John F. Turner		
/s/ SANDRA VAN TREASE	Director	February 27, 2008
Sandra Van Trease		
/s/ ALAN H. WASHKOWITZ	Director	February 27, 2008
Alan H. Washkowitz		

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited the accompanying consolidated balance sheets of Peabody Energy Corporation (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Peabody Energy Corporation at December 31, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, on January 1, 2007, the Company changed its method of accounting for uncertain tax positions, on January 1, 2006, the Company changed its method of accounting for stripping costs and share-based payments, and on December 31, 2006, the Company changed its method of accounting for defined pension benefit and other postretirement plans.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Peabody Energy Corporation s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 27, 2008, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 27, 2008

PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	**2006**	**2005**
	(Dollars in thousands, except share and per share data)		
Revenues			
Sales	$ 4,364,708	$ 4,002,403	$ 3,584,422
Other revenues	210,004	105,993	81,754
Total revenues	4,574,712	4,108,396	3,666,176
Costs and Expenses			
Operating costs and expenses	3,574,818	3,155,732	2,885,320
Depreciation, depletion and amortization	361,559	294,270	253,788
Asset retirement obligation expense	25,610	15,830	20,329
Selling and administrative expenses	147,146	128,031	132,679
Other operating income:			
Net gain on disposal or exchange of assets	(88,684)	(53,532)	(44,445)
Income from equity affiliates	(14,461)	(22,791)	(15,227)
Operating Profit	568,724	590,856	433,732
Interest expense	235,236	137,668	98,066
Early debt extinguishment costs	(253)	1,396	
Interest income	(7,094)	(11,309)	(9,088)
Income From Continuing Operations Before Income Taxes and Minority Interests	340,835	463,101	344,754
Income tax provision (benefit)	(78,112)	(90,084)	63,779
Minority interests	(2,316)	611	2,472
Income From Continuing Operations	421,263	552,574	278,503
Income (loss) from discontinued operations	(156,978)	48,123	144,150
Net Income	$ 264,285	$ 600,697	$ 422,653
Basic Earnings Per Share			
Income from continuing operations	$ 1.60	$ 2.10	$ 1.06
Income (loss) from discontinued operations	(0.60)	0.18	0.55
Net income	$ 1.00	$ 2.28	$ 1.61
Weighted Average Shares Outstanding Basic	264,068,180	263,419,344	261,519,424
Diluted Earnings Per Share			
Income from continuing operations	$ 1.56	$ 2.05	$ 1.04

Income (loss) from discontinued operations	(0.58)	0.18	0.54
Net income	$ 0.98	$ 2.23	$ 1.58
Weighted Average Shares Outstanding Diluted	269,166,290	269,166,005	268,013,476
Dividends Declared Per Share	$ 0.24	$ 0.24	$ 0.17

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	2006
	(Dollars in thousands, except share and per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 45,279	$ 326,511
Accounts receivable, net of allowance for doubtful accounts of $11,888 and $10,893 at December 31, 2007 and 2006, respectively	257,950	320,822
Inventories	268,862	202,909
Assets from coal trading activities	966,548	150,373
Deferred income taxes	98,633	77,562
Other current assets	215,928	109,859
Current assets of discontinued operations	74,093	108,522
Total current assets	1,927,293	1,296,558
Property, plant, equipment and mine development		
Land and coal interests	7,198,090	6,498,816
Buildings and improvements	700,509	622,059
Machinery and equipment	1,267,328	1,139,072
Less accumulated depreciation, depletion and amortization	(1,833,527)	(1,551,117)
Property, plant, equipment and mine development, net	7,332,400	6,708,830
Goodwill		240,667
Investments and other assets	408,614	304,518
Noncurrent assets of discontinued operations		963,483
Total assets	$ 9,668,307	$ 9,514,056
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 134,373	$ 95,757
Liabilities from coal trading activities	918,596	126,731
Accounts payable and accrued expenses	953,661	944,151
Current liabilities of discontinued operations	180,356	160,730
Total current liabilities	2,186,986	1,327,369
Long-term debt, less current maturities	3,138,727	3,181,275
Deferred income taxes	315,604	412,886
Asset retirement obligations	369,547	283,328
Accrued postretirement benefit costs	785,708	809,013
Other noncurrent liabilities	318,127	351,166

Noncurrent liabilities of discontinued operations	33,236	777,156
Total liabilities	7,147,935	7,142,193
Minority interests, including $16,153 of discontinued operations at December 31, 2006	701	33,337
Stockholders equity		
Preferred Stock $0.01 per share par value; 10,000,000 shares authorized, no shares issued or outstanding as of December 31, 2007 or 2006		
Series A Junior Participating Preferred Stock 1,500,000 shares authorized, no shares issued or outstanding as of December 31, 2007 or 2006		
Perpetual Preferred Stock 750,000 shares authorized, no shares issued or outstanding as of December 31, 2007 or 2006		
Series Common Stock $0.01 per share par value; 40,000,000 shares authorized, no shares issued or outstanding as of December 31, 2007 or 2006		
Common Stock $0.01 per share par value; 800,000,000 shares authorized, 272,911,564 shares issued and 270,066,621 shares outstanding as of December 31, 2007 and 800,000,000 shares authorized, 266,554,157 shares issued and 263,846,839 shares outstanding as of December 31, 2006	2,729	2,666
Additional paid-in capital	1,750,627	1,572,614
Retained earnings	941,424	1,115,994
Accumulated other comprehensive loss	(67,066)	(249,058)
Treasury shares, at cost: 2,844,943 shares as of December 31, 2007 and 2,707,318 shares as of December 31, 2006	(108,043)	(103,690)
Total stockholders equity	2,519,671	2,338,526
Total liabilities and stockholders equity	$ 9,668,307	$ 9,514,056

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2007	**2006**	**2005**
	(Dollars in thousands)		
Cash Flows From Operating Activities			
Net income	$ 264,285	$ 600,697	$ 422,653
(Income) loss from discontinued operations	156,978	(48,123)	(144,150)
Income from continuing operations	421,263	552,574	278,503
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	361,559	294,270	253,788
Deferred income taxes	(201,444)	(195,546)	10,436
Amortization of debt discount and debt issuance costs	7,185	7,410	6,938
Net gain on disposal or exchange of assets	(88,684)	(53,532)	(44,445)
Income from equity affiliates	(14,461)	(22,791)	(15,227)
Dividends received from equity affiliates	12,927	18,128	
Changes in current assets and liabilities, net of acquisitions:			
Accounts receivable, including securitization	64,871	(111,242)	(32,601)
Inventories	(63,440)	(30,210)	(62,628)
Net assets from coal trading activities	(77,631)	(9,419)	11,377
Other current assets	(56,459)	(20,339)	(12,016)
Accounts payable and accrued expenses	56,872	104,192	182,877
Asset retirement obligations	15,143	(3,058)	12,484
Workers compensation obligations	2,742	(86)	6,345
Accrued postretirement benefit costs	13,122	59,062	57,814
Distributions to minority interests	(2,975)	(4,545)	(2,498)
Contributions to pension plans	(5,322)	(6,146)	(7,162)
Other, net	1,913	12,690	39,819
Net cash provided by continuing operations	447,181	591,412	683,804
Net cash provided by (used in) discontinued operations	(130,816)	(8,150)	41,457
Net cash provided by operating activities	316,365	583,262	725,261
Cash Flows From Investing Activities			
Acquisition of Excel Coal, net of cash acquired		(1,507,775)	
Additions to property, plant, equipment and mine development	(470,434)	(397,497)	(450,348)
Federal coal lease expenditures	(178,193)	(178,193)	(118,364)
Proceeds from disposal of assets, net of notes receivable	119,586	29,411	62,731
Additions to advance mining royalties	(8,123)	(4,956)	(8,472)
Investments in joint ventures	(4,566)	(2,149)	(2,000)
Net cash used in continuing operations	(541,730)	(2,061,159)	(516,453)

Net cash used in discontinued operations	(33,602)	(82,659)	(67,749)
Net cash used in investing activities	(575,332)	(2,143,818)	(584,202)
Cash Flows From Financing Activities			
Change in revolving line of credit	97,700		
Proceeds from long-term debt		2,604,087	11,734
Payments of long-term debt	(117,817)	(1,045,973)	(20,198)
Common stock repurchase		(99,774)	
Dividends paid	(63,658)	(63,456)	(44,535)
Payment of debt issuance costs	(774)	(40,611)	
Excess tax benefit related to stock options exercised	96,743	33,173	
Proceeds from stock options exercised	26,197	15,617	22,573
Issuance of notes payable			(11,459)
Proceeds from employee stock purchases	6,377	4,518	3,009
Net cash provided by (used in) continuing operations	44,768	1,407,581	(38,876)
Net cash provided by (used in) discontinued operations	(67,033)	(23,792)	11,459
Net cash provided by (used in) financing activities	(22,265)	1,383,789	(27,417)
Net increase (decrease) in cash and cash equivalents	(281,232)	(176,767)	113,642
Cash and cash equivalents at beginning of year	326,511	503,278	389,636
Cash and cash equivalents at end of year	$ 45,279	$ 326,511	$ 503,278

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

	Common Stock	Additional Paid-In Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Treasury Stock	Total Stockholders Equity
			(Dollars in thousands)			
December 31, 2004	$ 2,596	$ 1,435,562	$ (60,618)	$ 350,968	$ (3,916)	$ 1,724,592
Comprehensive income:						
Net income				422,653		422,653
Increase in fair value of cash flow hedges (net of $7,613 tax provision)			11,421			11,421
Minimum pension liability adjustment (net of $1,601 tax provision)			2,402			2,402
Comprehensive income						436,476
Dividends paid				(44,535)		(44,535)
Stock options exercised	36	22,627				22,663
Income tax benefits from stock options exercised		30,437				30,437
Employee stock purchases	2	3,007				3,009
Employee stock grants	4	(4)				
Share-based compensation		5,825				5,825
December 31, 2005	$ 2,638	$ 1,497,454	$ (46,795)	$ 729,086	$ (3,916)	$ 2,178,467
Comprehensive income:						
Net income				600,697		600,697
Increase in fair value of cash flow hedges (net of $16,230 tax provision)			24,347			24,347
Minimum pension liability adjustment (net of $16,842 tax provision)			22,377			22,377
Comprehensive income						647,421
Postretirement plans and workers compensation obligations (net of $149,499 tax benefit):						
Accumulated actuarial loss, net of tax			(241,954)			
Prior service cost, net of tax			(7,033)			

			(248,987)			(248,987)
Dividends paid				(63,456)		(63,456)
Stock options exercised	20	15,600				15,620
Share-based compensation		21,877				21,877
Income tax benefits from stock options exercised		33,173				33,173
Employee stock purchases	2	4,516				4,518
Employee stock grants	6	(6)				
Advance stripping adjustment (net of $95,189 tax benefit)				(150,333)		(150,333)
Shares repurchased					(99,774)	(99,774)
December 31, 2006	$ 2,666	$ 1,572,614	$ (249,058)	$ 1,115,994	$ (103,690)	$ 2,338,526
Comprehensive income:						
Net income				264,285		264,285
Increase in fair value of cash flow hedges (net of $14,530 tax provision)			21,796			21,796
Postretirement plans and workers compensation obligations (net of $50,232 tax provision):			87,211			87,211
Comprehensive income						373,292
Dividends paid				(63,658)		(63,658)
Patriot Coal Corp. spin-off			72,985	(375,197)		(302,212)
Stock options exercised	54	26,143				26,197
Income tax benefits from stock options exercised		96,743				96,743
Employee stock purchases	2	6,375				6,377
Employee stock grants	7	(7)				
Share-based compensation		48,759				48,759
Shares relinquished					(4,353)	(4,353)
December 31, 2007	$ 2,729	$ 1,750,627	$ (67,066)	$ 941,424	$ (108,043)	$ 2,519,671

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of Peabody Energy Corporation (the Company) and its affiliates. All intercompany transactions, profits and balances have been eliminated in consolidation.

Description of Business

The Company is engaged in the mining of steam coal for sale primarily to electric utilities and metallurgical coal for sale to industrial customers. The Company s mining operations are located in the United States and Australia, and include an equity interest in mining operations in Venezuela. In addition to the Company s mining operations, the Company markets, brokers and trades coal. The Company s other energy related commercial activities include the development of mine-mouth coal-fueled generating plants, the management of its vast coal reserve and real estate holdings, coalbed methane production and Btu conversion technologies. The Company s Btu conversion projects are designed to expand the uses of coal through various technologies such as coal-to-liquids and coal gasification.

New Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 123 (revised 2004), Share-Based Payment (SFAS No. 123(R)), which is a revision of SFAS No. 123, Accounting for Stock-Based Compensation (SFAS No. 123). SFAS No. 123(R) supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees (APB Opinion No. 25) and amends FASB Statement No. 95, Statement of Cash Flows. Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) requires all share-based payments to employees, including employee stock options, to be recognized in the income statement based on their fair values at the grant date.

The Company adopted SFAS No. 123(R) on January 1, 2006 and used the modified prospective method, in which compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS No. 123(R) for all share-based payments granted or modified after the effective date and (b) based on the requirements of SFAS No. 123 for all awards granted to employees prior to the effective date of SFAS No. 123(R) that remain unvested on the effective date. Prior to January 1, 2006, the Company had elected to apply APB Opinion No. 25 and related interpretations in accounting for its stock option plans, as permitted under SFAS No. 123 and SFAS No. 148 Accounting for Stock-Based Compensation-Transition and Disclosure. Beginning in 2006, SFAS No. 123(R) also requires that excess income tax benefits from stock options exercised be recorded as financing cash inflow on the statements of cash flows. The excess income tax benefit from stock option exercises during 2005 is included in operating cash flows, netted in deferred tax activity.

In March 2005, the Emerging Issues Task Force (EITF) issued EITF Issue No. 04-6, Accounting for Stripping Costs in the Mining Industry (EITF Issue No. 04-6). EITF Issue No. 04-6 and its interpretations require stripping costs incurred during a period to be attributed only to the inventory costs of the coal that is extracted during that same period. The Company adopted EITF Issue No. 04-6 on January 1, 2006 and utilized the cumulative effect adjustment approach whereby the cumulative effect adjustment reduced retained earnings by $150.3 million, net of tax. This non-cash item is excluded from the consolidated statements of cash flows. Advance stripping costs are primarily

expensed as incurred.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS No. 158). For fiscal years ending after December 15, 2006, SFAS No. 158 requires recognition of the funded status of pension and other postretirement benefit plans (an

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

asset for overfunded status or a liability for underfunded status) in a company s balance sheet. In addition, the standard requires recognition of actuarial gains and losses, prior service cost, and any remaining transition amounts from the initial application of SFAS No. 87, Employers Accounting for Pensions (SFAS No. 87) and SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions (SFAS No. 106) when determining a plan s funded status, with a corresponding charge to accumulated other comprehensive income (loss).

The Company adopted SFAS No. 158 on December 31, 2006, and as a result, recorded a noncurrent liability of $376.1 million, which reflected the net underfunded status of the pension, retiree healthcare and workers compensation plans. The funded status of each plan was measured as the difference between the fair value of the assets and the projected benefit obligation (the funded status). SFAS No. 158 did not impact net income.

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN No. 48). This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

The Company adopted the provisions of FIN No. 48 on January 1, 2007, and as a result, reported $135.0 million of net unrecognized tax benefits ($144.0 million gross) in its consolidated financial statements. Due to the valuation allowance recorded against the Company s deferred tax asset for net operating loss (NOL) carryforwards as of January 1, 2007, none of the $135.0 million required an adjustment to retained earnings upon adoption.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements, and therefore does not require any new fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 (January 1, 2008 for the Company). In February 2008, the FASB amended SFAS No. 157 to exclude leasing transactions and to delay the effective date by one year for nonfinancial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. The Company is in the process of determining the effect, if any, the adoption of SFAS No. 157 will have on its financial statements.

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 all entities with an option to report selected financial assets and liabilities at fair value. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007 (January 1, 2008 for the Company). The Company is in the process of determining the effect, if any, the adoption of SFAS No. 159 will have on its financial statements.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 establishes accounting and reporting standards for (1) noncontrolling interests in partially owned consolidated subsidiaries and (2) the loss of control of subsidiaries. SFAS No. 160 requires noncontrolling interests (minority interests) to be reported as a separate component of equity. The amount of net income attributable to the noncontrolling interest will be included in consolidated net income on

the face of the income statement. In addition, this statement requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. Such gain or loss will be measured using the fair value of the noncontrolling equity investment on the deconsolidation date. SFAS 160 also includes expanded disclosure requirements regarding the interests of the parent and its

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

noncontrolling interest. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 (January 1, 2009 for the Company). Early adoption is not allowed. The Company is in the process of determining the effect the adoption of SFAS No. 160 will have on its financial statements.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which replaces SFAS No. 141. SFAS No. 141(R) significantly changes the principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. This statement also provides guidance for recognizing and measuring the goodwill acquired in the business combination and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 (January 1, 2009 for the Company). The Company is in the process of determining the effect, if any, the adoption of SFAS No. 141(R) will have on its financial statements.

Sales

The Company s revenue from coal sales is realized and earned when risk of loss passes to the customer. Coal sales are made to the Company s customers under the terms of coal supply agreements, most of which are long-term (greater than one year). Under the typical terms of these coal supply agreements, title and risk of loss transfer to the customer at the mine or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s) that serves each of the Company s mines. The Company incurs certain add-on taxes and fees on coal sales. Coal sales are reported including taxes and fees charged by various federal and state governmental bodies. Coal sales includes the freight charges on destination customer contracts.

Other Revenues

Other revenues include royalties related to coal lease agreements, sales agency commissions, farm income, coalbed methane revenues, property and facility rentals, generation development activities, net revenues from coal trading activities accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), as amended, and contract termination or restructuring payments. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced. Certain agreements require minimum annual lease payments regardless of the extent to which minerals are produced from the leasehold. The terms of these agreements generally range from specified periods of five to 15 years, or can be for an unspecified period until all reserves are depleted.

Discontinued Operations

The Company classifies items within discontinued operations in the consolidated statements of operations when the operations and cash flows of a particular component (defined as operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the entity) of the Company have been (or will be) eliminated from the ongoing operations of the Company as a result of a disposal transaction, and the Company will no longer have any significant continuing involvement in the operations of that component. Discontinued operations, net of taxes, for the years ended December 31, 2007, 2006, and 2005, reflected a

$157.0 million loss, $48.1 million income, and $144.2 million income, respectively, related to the spin-off of Patriot Coal Corporation (Patriot). See Note 2 for additional details related to discontinued operations.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents consist of highly liquid investments with original maturities of three months or less.

Inventories

Materials and supplies and coal inventory are valued at the lower of average cost or market. Raw coal represents coal stockpiles that may be sold in current condition or may be further processed prior to shipment to a customer. Coal inventory costs include labor, supplies, equipment, operating overhead and other related costs.

Assets and Liabilities from Coal Trading Activities

The Company s coal trading activities are evaluated under SFAS No. 133, as amended. Trading contracts that meet the SFAS No. 133 definition of a derivative are accounted for at fair value, while contracts that do not qualify as derivatives are accounted for under the accrual method. All trading contracts are recorded subject to the requirements of EITF Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities (EITF Issue No. 02-3).

The Company s trading contracts are reflected at fair value and are included in Assets and liabilities from coal trading activities in the consolidated balance sheets as of December 31, 2007 and 2006. Under EITF Issue No. 02-3, all mark-to-market gains and losses on energy trading contracts (including derivatives and hedged contracts) are presented on a net basis in the statement of operations, even if settled physically. The Company s consolidated statements of operations reflect revenues related to all mark-to-market trading contracts on a net basis in Other revenues.

Property, Plant, Equipment and Mine Development

Property, plant, equipment and mine development are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period, including $2.0 million, $3.0 million and $0.1 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Maintenance and repairs are charged to operating costs as incurred. Costs incurred to develop coal mines or to expand the capacity of operating mines are capitalized. Costs incurred to maintain current production capacity at a mine and exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Costs to acquire computer hardware and the development and/or purchase of software for internal use are capitalized and depreciated over the estimated useful lives.

Coal reserves are recorded at cost, or at fair value in the case of acquired businesses. As of December 31, 2007 and 2006, the net book value of coal reserves totaled $5.6 billion and $4.6 billion, respectively. These amounts included $2.1 billion and $1.7 billion at December 31, 2007 and 2006, respectively, attributable to properties where the Company was not currently engaged in mining operations or leasing to third parties and, therefore, the coal reserves were not currently being depleted. Included in the book value of coal reserves are mineral rights for leased coal

interests including advance royalties and the net book value of these mineral rights was $2.2 billion and $3.2 billion at December 31, 2007 and 2006, respectively. The remaining net book value of the Company s coal reserves of $3.4 billion and $1.4 billion, at December 31, 2007 and 2006, respectively, relates to coal reserves held by fee ownership.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Depletion of coal reserves and amortization of advance royalties is computed using the units-of-production method utilizing only proven and probable reserves (as adjusted for recoverability factors) in the depletion base. Mine development costs are principally amortized over the estimated lives of the mines using the straight-line method. Depreciation of plant and equipment (excluding life of mine assets) is computed using the straight-line method over the estimated useful lives as follows:

	Years
Building and improvements	10 to 20
Machinery and equipment	3 to 29
Leasehold improvements	Life of Lease

In addition, certain plant and equipment assets associated with mining are depreciated using the straight-line method over the estimated life of the mine, which varies from one to 29 years.

Investments in Joint Ventures

The Company accounts for its investments in less than majority owned corporate joint ventures under either the equity or cost method. The Company applies the equity method to investments in joint ventures when it has the ability to exercise significant influence over the operating and financial policies of the joint venture. Investments accounted for under the equity method are initially recorded at cost, and any difference between the cost of the Company s investment and the underlying equity in the net assets of the joint venture at the investment date is amortized over the lives of the related assets that gave rise to the difference. The Company s pro rata share of earnings from joint ventures and basis difference amortization is reported in the consolidated statements of operations in Income from equity affiliates. The book value of the Company s equity method investments as of December 31, 2007 and 2006 was $76.7 million and $65.1 million, respectively, and is reported in Investments and other assets in the consolidated balance sheets. Included in the Company s equity method investments was its 25.5% interest in Carbones del Guasare, which owns and operates the Paso Diablo Mine in Venezuela. The Company s investment in Paso Diablo was $68.4 million and $60.1 million as of December 31, 2007 and 2006, respectively. The Company recorded income from this equity affiliate of $21.2 million, $28.0 million and $20.0 million for the years ended December 31, 2007, 2006 and 2005, respectively, which is reported in Income from equity affiliates in the consolidated statements of operations. The Company received dividends from this equity affiliate of $12.9 million and $18.1 million for the years ended December 31, 2007 and 2006, respectively, while no dividends were received for the year ended December 31, 2005.

Generation Development Costs

Development costs related to coal-based electricity generation, including expenditures for permitting and licensing, are capitalized at cost under the guidelines in SFAS No. 142, Goodwill and Other Intangible Assets. Start-up costs, as defined in Statement of Position (SOP) No. 98-5, Reporting on the Costs of Start-up Activities, are expensed as incurred. Development costs of $36.9 million and $21.4 million were recorded as part of Investments and other assets in the consolidated balance sheets as of December 31, 2007 and 2006, respectively.

Asset Retirement Obligations

SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143) addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The Company s asset retirement obligation (ARO) liabilities primarily consist of spending estimates related to reclaiming surface land and support facilities at both surface and underground mines in accordance with applicable reclamation laws as defined by each mining permit.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company estimates its ARO liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash spending for a third-party to perform the required work. Spending estimates are escalated for inflation and then discounted at the credit-adjusted, risk-free rate. The Company records an ARO asset associated with the discounted liability for final reclamation and mine closure. The obligation and corresponding asset are recognized in the period in which the liability is incurred. The ARO asset is amortized on the units-of-production method over its expected life and the ARO liability is accreted to the projected spending date. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free rate. The Company also recognizes an obligation for contemporaneous reclamation liabilities incurred as a result of surface mining. Contemporaneous reclamation consists primarily of grading, topsoil replacement and revegetation of backfilled pit areas.

Environmental Liabilities

Included in Other noncurrent liabilities are accruals for other environmental matters that are recorded in operating expenses when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Accrued liabilities are exclusive of claims against third parties and are not discounted. In general, costs related to environmental remediation are charged to expense.

Income Taxes

Income taxes are accounted for using a balance sheet approach in accordance with SFAS No. 109, Accounting for Income Taxes. The Company accounts for deferred income taxes by applying statutory tax rates in effect at the date of the balance sheet to differences between the book and tax basis of assets and liabilities. A valuation allowance is established if it is more likely than not that the related tax benefits will not be realized. In determining the appropriate valuation allowance, the Company considers projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies, and the overall deferred tax position.

FIN No. 48 Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company adopted this interpretation effective January 1, 2007.

Postretirement Health Care and Life Insurance Benefits

The Company accounts for postretirement benefits other than pensions in accordance with SFAS No. 106, which requires the costs of benefits to be provided to be accrued over the employees period of active service. These costs are determined on an actuarial basis. As a result of the adoption of SFAS No. 158 on December 31, 2006, the Company s consolidated balance sheet reflects the funded status of postretirement benefits.

Pension Plans

The Company sponsors non-contributory defined benefit pension plans accounted for in accordance with SFAS No. 87, which requires that the cost to provide the benefits be accrued over the employees period of active service. These costs are determined on an actuarial basis. SFAS No. 158 amended SFAS No. 87 and as a result of the adoption of SFAS No. 158 on December 31, 2006, the Company s consolidated balance sheet reflects the funded status of the defined benefit pension plans.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Postemployment Benefits

The Company provides postemployment benefits to qualifying employees, former employees and dependents and accounts for these benefits on the accrual basis in accordance with SFAS No. 112 Employers Accounting for Postemployment Benefits. Postemployment benefits include workers compensation occupational disease, which is accounted for on the actuarial basis over the employees period of active service; workers compensation traumatic injury claims, which are accounted for based on estimated loss rates applied to payroll and claim reserves determined by independent actuaries and claims administrators; disability income benefits, which are accrued when a claim occurs; and continuation of medical benefits, which are recognized when the obligation occurs. As a result of the adoption of SFAS No. 158 on December 31, 2006, the Company s consolidated balance sheet reflects the funded status of postemployment benefits.

Derivatives

SFAS No. 133, as amended, requires the recognition at fair value of all derivatives as assets or liabilities on the consolidated balance sheets. Gains or losses from derivative financial instruments designated as fair value hedges are recognized immediately in the consolidated statements of operations, along with the offsetting gain or loss related to the underlying hedged item.

Gains or losses on derivative financial instruments designated as cash flow hedges are recorded as a separate component of stockholders equity until settlement (or until hedge ineffectiveness is determined), whereby gains or losses are reclassified to the consolidated statements of operations in conjunction with the recognition of the underlying hedged item. To the extent that the periodic changes in the fair value of the derivatives are not effective, or if the hedge ceases to qualify for hedge accounting, the ineffective portion of the periodic non-cash changes are recorded in Operating costs and expenses in the consolidated statement of operations in the period of the change. The potential for hedge ineffectiveness is only present in the design of the hedge relationship in the Company s cash flow hedges of anticipated fuel purchases (see Note 3 for additional details).

Use of Estimates in the Preparation of the Consolidated Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles 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 reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

In particular, the Company has significant long-term liabilities relating to retiree health care, work-related injuries and illnesses and defined benefit pension plans. Each of these liabilities is actuarially determined and the Company uses various actuarial assumptions, including the discount rate and future cost trends, to estimate the costs and obligations for these items. In addition, the Company has significant asset retirement obligations that involve estimations of costs to remediate mining lands and the timing of cash outlays for such costs. If these assumptions do not materialize as expected, actual cash expenditures and costs incurred could differ materially from current estimates. Moreover, regulatory changes could increase the obligation to satisfy these or additional obligations.

Finally, in evaluating the valuation allowance related to the Company s deferred tax assets, the Company takes into account various factors, including the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in the evaluation of the valuation allowance, the Company may record a change in valuation allowance through income tax expense in the period such determination is made.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Impairment of Long-Lived Assets

The Company records impairment losses on long-lived assets used in operations when events and circumstances indicate that assets might be impaired and the undiscounted cash flows estimated to be generated by those assets under various assumptions are less than the carrying amounts of the assets. Impairment losses are measured by comparing the estimated fair value of the impaired asset to its carrying amount. There were no impairment losses recorded during the periods covered by the consolidated financial statements.

Fair Value of Financial Instruments

SFAS No. 107, Disclosures About Fair Value of Financial Instruments, defines the fair value of a financial instrument as the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced or liquidation sale. See Note 21 for additional information.

Foreign Currency Translation

The Company s foreign subsidiaries utilize the U.S. dollar as their functional currency. As such, monetary assets and liabilities are translated at year-end exchange rates while non-monetary items are translated at historical rates. Income and expense accounts are translated at the average rates in effect during the year, except for those expenses related to balance sheet amounts that are remeasured at historical exchange rates. Gains and losses from foreign currency remeasurement are included in the consolidated statements of operations with amounts related to the remeasurement of deferred tax balances included as a component of the income tax provision. The foreign currency remeasurement loss for the years ended December 31, 2007 and 2006 was $60.4 million and $12.8 million, respectively. Gains and losses from foreign currency remeasurement did not have a material impact on the Company s consolidated results of operations for the year ended December 31, 2005.

Business Combinations

The Company accounts for its business acquisitions under the purchase method of accounting consistent with the requirements of SFAS No. 141, Business Combinations. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management s judgment, and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates, asset lives, and market multiples, among other items.

Share-Based Compensation

The Company accounts for share-based compensation in accordance with the fair value recognition provisions of SFAS No. 123 (Revised 2004), Share-Based Payment (SFAS 123(R)), which the Company adopted using the modified prospective option on January 1, 2006. Under SFAS No. 123(R), share-based compensation expense is generally measured at the grant date and recognized as expense over the vesting period of the award.

Reclassifications

Certain amounts in prior periods have been reclassified to conform with the presentation of 2007, with no effect on previously reported net income or stockholders equity.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Discontinued Operations

On October 10, 2007, the Company s Board of Directors approved a spin-off of portions of its Eastern U.S. Mining operations business segment. The spin-off was accomplished on October 31, 2007 through a dividend of all outstanding shares of Patriot, which is now an independent public company traded on the New York Stock Exchange (symbol PCX). Prior to the spin-off, the Company received necessary regulatory approvals including a private letter ruling on the tax-free nature of the transaction from the Internal Revenue Service, and a declaration of effectiveness for Patriot s registration statement on Form 10 with the Securities and Exchange Commission (SEC). Distribution of the Patriot stock to the Company s stockholders occurred on October 31, 2007, at a ratio of one share of Patriot stock for every 10 shares of Peabody stock held on the record date of October 22, 2007.

The spin-off included eight company-operated mines, two joint venture mines, and numerous contractor operated mines serviced by eight coal preparation facilities along with 1.2 billion tons of proven and probable coal reserves. Revenues, pretax income (loss) and the income tax provision (benefit) reported in discontinued operations were as follows.

	Year Ended December 31,		
	2007	2006	2005
	(Dollars in thousands)		
Revenues	$ 1,024,462	$ 1,147,919	$ 978,277
Income (loss) before income taxes and minority interests	(235,215)	67,861	81,331
Income tax provision (benefit)	(81,473)	8,569	(62,819)

The Company entered into agreements to pay for certain retiree healthcare liabilities of Patriot arising under the Coal Act and the 2007 National Bituminous Coal Wage Agreement (NBCWA), as well as retiree healthcare liabilities relating to certain Patriot salaried employees. These liabilities totaled $617 million at October 31, 2007 and are included in accrued postretirement benefit costs.

The 2007 loss before income taxes and minority interests totaling $235.2 million includes certain charges taken in connection with the spin-off including a $162.2 million loss related to firm purchase commitments that extend through 2010 for purchases from Patriot to supply pre-existing below market customer sales contracts that will be sourced from Patriot operations, $23.8 million of accelerated vesting of share-based compensation awarded to Patriot executives and $21.5 million of transaction related costs.

The Company has also entered into a transition services agreement to provide certain administrative and other services to Patriot for a period of six months. Patriot will have the option to extend this agreement for an additional term of three months and, under certain circumstances, for another term of three months. Under this agreement, the Company billed $0.9 million for transitional services in the last two months of 2007.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The assets, liabilities and minority interests of the discontinued operations as of December 31, 2007 and 2006 are shown below.

	December 31,	
	2007	2006
	(Dollars in thousands)	
Assets		
Current assets		
Accounts receivable, net	$ 74,093	$ 37,420
Inventories		34,693
Deferred income taxes		29,405
Other current assets		7,004
Total current assets	74,093	108,522
Property, plant, equipment and mine development, net		842,687
Investments and other assets		120,796
Total assets	$ 74,093	$ 1,072,005
Liabilities		
Current liabilities		
Accounts payable and accrued expenses	$ 180,356	$ 160,730
Total current liabilities	180,356	160,730
Long-term debt, less current maturities		20,717
Deferred income taxes		(217,673)
Asset retirement obligations		139,703
Workers compensation obligations		211,500
Accrued postretirement benefit costs		559,673
Other noncurrent liabilities	33,236	63,236
Total liabilities	$ 213,592	$ 937,886
Minority interests	$	$ 16,153

(3) Risk Management and Derivative Financial Instruments

The Company is exposed to various types of risk in the normal course of business, including fluctuations in commodity prices, interest rates and foreign currency exchange rates. These risks are actively monitored to ensure compliance with the risk management policies of the Company. In most cases, commodity price risk (excluding coal trading activities) related to the sale of coal is mitigated through the use of long-term, fixed-price contracts rather than

financial instruments, while commodity price risk related to materials used in production is managed through the use of fixed price and cost plus contracts and derivatives. Interest rate and foreign currency exchange risk are managed through the use of forward contracts, swaps and options. The Company s usage of interest rate swaps is discussed in Note 13.

Commodity Price Risk

In addition to the derivatives related to coal trading activities, the Company manages its exposure to price volatility of materials used in production, including diesel fuel and explosives, through various contractual arrangements. As of December 31, 2007, the Company had designated derivative contracts as cash flow

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

hedges for 114.8 million gallons of anticipated fuel usage with contract maturities extending through 2010. The consolidated balance sheet at December 31, 2007 reflects unrealized gains on these cash flow hedges of $48.4 million, which is recorded net of a $19.4 million tax provision in Accumulated other comprehensive loss (see Note 19).

A measure of ineffectiveness is inherent in hedging future diesel fuel purchases with derivative positions based on crude oil or other mid-distillate commodities. The amount of ineffectiveness in the Company s hedge of physical fuel purchases with heating oil derivatives has historically been insignificant and is expected to remain minimal because the hedged diesel fuel contracts are priced based on the underlying derivative, heating oil, adjusted for a fixed transportation differential. Due to the market volatility of crude oil prices and refining spreads, the measured ineffectiveness in the Company s hedges of physical diesel fuel purchases with crude oil derivatives has historically been greater than for hedging contracts based on heating oil. Due to the implicit market volatility of crude and heating oil prices and refining crack spreads, the Company is unable to predict the amount of ineffectiveness that may occur in future periods, including the loss of hedge accounting (which could be determined on a derivative by derivative basis or in the aggregate), which may result in increased volatility in the Company s future results.

Due to the inherent ineffectiveness that occurs when the price of a derivative contract does not perfectly mirror the value of the hedged instrument or transaction, SFAS No. 133 permits a degree of ineffectiveness within a narrowly defined corridor, provided that critical terms of the hedge contract and the hedged activity are sufficiently matched, including maturity and notional amount, and provided that historical and expected future prices are sufficiently correlated. During 2007 and 2006, the Company did not recognize any impact due to ineffectiveness of hedging contracts that exceeded the defined corridor stipulated in SFAS No. 133.

The notional amounts outstanding of 114.8 million gallons of derivative swap contracts for crude oil that were designated as cash flow hedges of future anticipated diesel fuel purchases as of December 31, 2007. The crude oil swaps are used to hedge incremental fuel purchases in the Company s Eastern mining operations with any excess over Eastern requirements allocated to Western operations.

In addition to the derivatives related to trading activities and diesel fuel, the Company enters contracts to manage its exposure to the price volatility of explosives. As of December 31, 2007, the Company had derivative contracts designated as cash flow hedges with notional amounts outstanding totaling 5.7 million MMBtu of natural gas, with maturities extending through August 2010. The consolidated balance sheet as of December 31, 2007, reflects unrealized losses on these cash flow hedges of $2.0 million, which is recorded net of a $0.8 million tax benefit in Accumulated other comprehensive loss (see Note 19). The Company s hedge of explosives with natural gas is perfectly effective by design since the contractual purchase of explosives is fixed to the previous month s closing price for natural gas, which occurs in a constant ratio of MMBtu per ton in the manufacture of explosives, plus a fixed surcharge.

Credit Risk

The Company s concentration of credit risk is substantially with energy producers and marketers and electric utilities, although it also has exposure to international steel producers, brokerage sources and trading counterparties. The Company s policy is to independently evaluate each customer s creditworthiness prior to entering into transactions and to constantly monitor the credit extended. In the event that the Company enters into a transaction with a counterparty that does not meet its credit standards, the Company may protect its position by requiring the counterparty to provide

appropriate credit enhancement.

When appropriate, the Company has taken steps to reduce the Company s credit exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk, as determined by the Company s credit management function, of failure to perform under their contractual obligations. These steps include

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for the Company s benefit to fund payment for coal under existing coal supply agreements.

To reduce the Company s credit exposure related to its trading and brokerage activities, the Company seeks to enter into netting agreements with counterparties that permit the Company to offset receivables and payables with such counterparties. Counterparty risk with respect to interest rate swap and foreign currency forwards transactions is not considered to be significant based upon the creditworthiness of the participating financial institutions.

Foreign Currency Risk

The Company utilizes currency forwards to hedge currency risk associated with anticipated Australian dollar expenditures. As of December 31, 2007, the Company had forward contracts designated as cash flow hedges with notional amounts outstanding totaling approximately A$2.03 billion, with maturities extending through 2010. The consolidated balance sheet as of December 31, 2007, reflects unrealized gains on the cash flow hedges of $124.8 million, which is recorded net of a $49.9 million tax benefit in Accumulated other comprehensive loss (see Note 19).

Employees

As of December 31, 2007, the Company had approximately 7,000 employees. As of December 31, 2007, approximately 27% of the Company s hourly employees were represented by organized labor unions and generated 10% of the 2007 coal production. Relations with its employees and, where applicable, organized labor are important to the Company s success.

United States Labor Relations

The United Mine Workers of America (UMWA) represented approximately 6% of the Company s U.S. subsidiaries hourly employees, who generated 4% of the Company s U.S. production during the year ended December 31, 2007. An additional 7% of the U.S. hourly employees are represented by labor unions other than the UMWA. These employees generated 2% of the Company s U.S. production during the year ended December 31, 2007. Hourly workers at the Company s mine in Arizona are represented by the UMWA under the Western Surface Agreement, which is effective through September 2, 2013. In April 2007, a new labor agreement was ratified for the Company s hourly workforce at the Willow Lake underground mine, which is represented by the International Brotherhood of Boilermakers. The new four-year labor agreement expires on April 15, 2011.

Australia Labor Relations

The Australian coal mining industry is unionized and all of the Company s hourly workers and those employed through contract mining relationships are members of trade unions. The Construction Forestry Mining and Energy Union represents the Company s Australian subsidiary s hourly production employees. As of December 31, 2007, the Company s Australian hourly employees were approximately 26% of its hourly workforce and generated 29% of the Company s total Australian production in the year then ended. The labor agreements at the Company s Metropolitan Mine were renewed in July and October 2007 and those agreements expire in 2010. The Wambo mine coal handling plant labor agreement is under negotiation and the North Goonyella Mine operates under an agreement due to expire

in March 2008.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(4) Resource Management and Other Commercial Events

During 2007, the Company purchased approximately 345 million tons of coal reserves and surface lands in the Illinois Basin. In conjunction with the purchase, the Company also agreed to provide up to $64.8 million of reclamation and bonding commitments to a third-party coal company. The Company has recognized the full amount of these commitments as a liability as of December 31, 2007. The non-cash portion of this transaction was excluded from the investing section of the statement of cash flows.

During 2007, the Company sold approximately 172 million tons of coal reserves and surface lands to the Prairie State Energy Campus (Prairie State) equity partners. The Company recognized a gain totaling $26.4 million and received $114.3 million in cash proceeds associated with this transaction. See Note 20 for additional information regarding Prairie State.

In 2007, the Company exchanged oil and gas rights and assets in more than 860,000 acres in the Illinois Basin, West Virginia, New Mexico and the Powder River Basin for approximately 40 million tons of high-Btu coal reserves in West Virginia and Kentucky and $15.0 million in cash proceeds. The Company s subsidiaries, including one subsidiary now owned by Patriot, received approximately 40 million tons of coal reserves. Based on the fair value of the coal reserves received, the Company recognized a $50.5 million gain on the exchange. The non-cash portion of this transaction was excluded from the investing section of the statement of cash flows.

In 2006, the Company exchanged approximately 63 million tons of coal reserves at its Caballo mining operation for approximately 46 million tons of coal reserves contiguous with the Company s North Antelope Rochelle mining operation. Based on the fair value of the coal reserves exchanged, the Company recognized a gain totaling $39.2 million. This non-cash transaction was excluded from the investing section of the statement of cash flows.

The Company recognized $35.8 million during the year ended December 31, 2006 in gains related to the settlement of commitments by a third-party coal producer following a brokerage contract restructuring. The gains are included in Other revenues in the consolidated statements of operations.

In the fourth quarter of 2005, the Company acquired rail, loadout and surface facilities as well as other mining assets from another major coal producer for $84.7 million and exchanged 60 million ton blocks of leased coal reserves in the Powder River Basin. The Company plans to utilize these reserves and infrastructure to accelerate the development of a new mine, which will include adjoining Company-leased reserves. In the first quarter of 2005, the Company purchased mining assets from Lexington Coal Company for $61.0 million, of which $56.5 million was recorded in Property, plant, equipment and mine development and the remainder recorded primarily to Inventories in the consolidated balance sheet. The Company used the acquired assets to open a new mine that produced 2.4 million tons of coal during 2006 and to provide other synergies to existing properties.

In the third quarter of 2005, the Company exchanged certain idle steam coal reserves for steam and metallurgical coal reserves as part of a contractual dispute settlement. Under the settlement, the Company received $10.0 million in cash, a new coal supply agreement that partially replaced the disputed coal supply agreement, and exchanged the idle steam coal reserves. As a result of the final settlement and based on the fair values of the items exchanged in the overall settlement transaction, the Company recorded net contract losses of $4.0 million and a gain on assets exchanged of $37.4 million. The fair value of assets exchanged exceeded the book value by $33.4 million and this non-cash addition

is not included in Additions to property, plant, equipment and mine development in the consolidated statements of cash flows. The gain from this transaction is included in Net gain on disposal or exchange of assets in the consolidated statements of operations.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(5) Business Combinations

Excel Coal Limited

In October 2006, the Company acquired Excel Coal Limited (Excel), an independent coal company, by means of a scheme of arrangement transaction under Australian law (the Transaction). The total acquisition price was $1.54 billion in cash plus assumed debt of $293.0 million, less $30.0 million of cash acquired in the transaction, and was financed with borrowings under the Company s Senior Unsecured Credit Facility and Senior Notes due 2016 and 2026 as discussed in Note 13. The Excel acquisition expands the Company s presence in Australia and included three operating mines and three development-stage mines (all of which are operating as of December 31, 2007), with up to 500 million tons of proven and probable coal reserves and approximately 100 million tons of coal resources. The results of operations of Excel are included in the Company s Australian Mining Operations segment from October 2006. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, Business Combinations.

The purchase accounting allocations related to the acquisition have been completed and recorded in the accompanying consolidated financial statements as of, and for periods subsequent to, October 2006. Pursuant to a final valuation, the adjustments to the Company s preliminary allocation were recorded in 2007 and resulted in an increase in the value assigned to property, plant and equipment and related deferred income taxes, thus eliminating the preliminary goodwill allocation. The following table summarizes the fair values of the assets acquired and the liabilities assumed at the date of acquisition:

	Preliminary Allocation	Adjustments	Final Allocation
	(Dollars in thousands)		
Accounts receivable, net	$ 18,700	$ 2,543	$ 21,243
Inventories	32,044	(1,325)	30,719
Other current assets	5,336	2,513	7,849
Property, plant, equipment and mine development, net	1,897,672	363,307	2,260,979
Goodwill	240,667	(240,667)	
Accounts payable and accrued expenses	(135,474)	(14,929)	(150,403)
Debt	(293,024)	9,508	(283,516)
Deferred income taxes, net	(179,026)	(114,083)	(293,109)
Other noncurrent assets and liabilities, net	(60,857)	(13,852)	(74,709)
Minority interests	(18,263)	6,985	(11,278)
Total purchase price, net of cash received of $29,995	$ 1,507,775	$	$ 1,507,775

In connection with the acquisition, the Company acquired contract based intangibles consisting solely of coal supply agreement obligations (customer contracts) and recorded a net intangible liability of $32.8 million. The net intangible liability is being amortized based on market differential and tonnage delivered over the terms of the applicable agreements, which range from 1 to 20 years. As of December 31, 2007, the carrying value of the net intangible

liability was $28.9 million and the amortization (reduction to Depreciation, depletion and amortization in the consolidated statement of operations) recorded through December 31, 2007 was $3.9 million.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Estimated amortization (reduction to Depreciation, depletion and amortization in the consolidated statement of operations) as of December 31, 2007 is as follows:

	Year Ended December 31, (Dollars in thousands)
2008	$ 9,414
2009	5,015
2010	4,245
2011	7,648
2012	182
Thereafter	2,351
Total	$ 28,855

The following unaudited pro forma financial information presents the combined results of operations of the Company and Excel, on a pro forma basis, as though the companies had been combined as of the beginning of each period presented. The pro forma financial information does not necessarily reflect the results of operations that would have occurred had the Company and Excel constituted a single entity during those periods.

	Year Ended December 31, 2006	2005
	(Dollars in thousands, except per share data)	
Revenues:		
As reported	$ 4,108,396	$ 3,666,176
Pro forma	4,403,428	3,994,514
Net income:		
As reported	$ 600,697	$ 422,653
Pro forma	569,956	364,258
Basic earnings per share net income:		
As reported	$ 2.28	$ 1.61
Pro forma	2.16	1.39
Diluted earnings per share net income:		
As reported	$ 2.23	$ 1.58
Pro forma	2.12	1.36

(6) Assets and Liabilities from Coal Trading Activities

The fair value of assets and liabilities from coal trading activities is set forth below:

	December 31,	
	2007	2006
	(Dollars in thousands)	
Assets from coal trading activities	$ 966,548	$ 150,373
Liabilities from coal trading activities	918,596	126,731
Net assets from coal trading activities	$ 47,952	$ 23,642

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The recent increase in coal price volatility and trading volumes, particularly in the Company s international markets, has significantly increased the relative value of the Company s trading asset and liability portfolio. Trading assets and liabilities are primarily forward contracts with financial swaps representing most of the remaining balance. The net value of trading assets and liabilities represents the future realizable value of the trading portfolio.

Of the coal trading derivatives and related hedge contracts in the Company s trading portfolio as of December 31, 2007, 97% were valued utilizing prices from over-the-counter market sources, adjusted for coal quality and traded transportation differentials and 3% of the Company s contracts were valued based on similar market transactions.

As of December 31, 2007, the estimated future realization of the value of the Company s trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio
2008	58%
2009	41%
2010	0%
2011	1%
	100%

At December 31, 2007, 27% of the Company s credit exposure related to coal trading activities with investment grade counterparties and 73% with non-investment grade counterparties. The Company s coal trading operations traded 166.5 million tons, 79.1 million tons and 36.2 million tons for the years ended December 31, 2007, 2006 and 2005, respectively.

(7) Accounts Receivable Securitization

The Company has established an accounts receivable securitization program through its wholly-owned, bankruptcy-remote subsidiary (Seller). Under the program, the Company contributes undivided interests in a pool of eligible trade receivables to the Seller, which then sells, without recourse, to a multi-seller, asset-backed commercial paper conduit (Conduit). Purchases by the Conduit are financed with the sale of highly rated commercial paper. The Company utilizes proceeds from the sale of its accounts receivable as an alternative to other forms of debt, effectively reducing its overall borrowing costs. The funding cost of the securitization program was $11.2 million, $1.9 million and $2.5 million for the years ended December 31, 2007, 2006 and 2005, respectively. The securitization program is scheduled to expire in September 2009.

The securitization transactions have been recorded as sales, with those accounts receivable sold to the Conduit removed from the consolidated balance sheets. The amount of undivided interests in accounts receivable sold to the Conduit was $275.0 million and $219.2 million as of December 31, 2007 and 2006, respectively.

The Seller is a separate legal entity whose assets are available first and foremost to satisfy the claims of its creditors. Eligible receivables, as defined in the securitization agreement, consist of trade receivables from most of the Company s U.S. subsidiaries, and are reduced for certain items such as past due balances and concentration limits. Of the eligible pool of receivables contributed to the Seller, undivided interests in only a portion of the pool are sold to the Conduit. The Company (the Seller) continues to own $186.5 million of receivables as of December 31, 2007, that represents collateral supporting the securitization program. The Seller s interest in these receivables is subordinate to the Conduit s interest in the event of default under the securitization agreement. If the Company defaulted under the securitization agreement or if its pool of eligible

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

trade receivables decreased significantly, the Company could be prohibited from selling any additional receivables in the future under the agreement.

(8) Earnings per Share

A reconciliation of weighted-average shares outstanding follows:

	Year Ended December 31,		
	2007	**2006**	**2005**
Weighted-average shares outstanding basic	264,068,180	263,419,344	261,519,424
Dilutive impact of stock options, restricted stock units and performance units	5,098,110	5,746,661	6,494,052
Weighted-average shares outstanding diluted	269,166,290	269,166,005	268,013,476

(9) Inventories

Inventories consisted of the following:

	December 31,	
	2007	**2006**
	(Dollars in thousands)	
Materials and supplies	$ 90,242	$ 71,899
Raw coal	55,524	37,996
Saleable coal	123,096	93,014
Total	$ 268,862	$ 202,909

(10) Leases

The Company leases equipment and facilities under various noncancelable lease agreements. Certain lease agreements require the maintenance of specified ratios and contain restrictive covenants which limit indebtedness, subsidiary dividends, investments, asset sales and other Company actions. Rental expense under operating leases was $104.7 million, $78.5 million and $78.6 million for the years ended December 31, 2007, 2006 and 2005, respectively. The gross value of property, plant, equipment and mine development assets under capital leases was $116.9 million and $72.3 million as of December 31, 2007 and 2006, respectively, related primarily to the leasing of mining equipment. The gross accumulated amortization for these items was $24.7 million and $15.6 million at December 31, 2007 and 2006, respectively.

The Company also leases coal reserves under agreements that require royalties to be paid as the coal is mined. Certain agreements also require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Total royalty expense was $343.1 million, $285.7 million and $255.2 million for the years ended December 31, 2007, 2006 and 2005, respectively.

A substantial amount of the coal mined by the Company is produced from mineral reserves leased from the owner. One of the major lessors is the U.S. government, from which the Company leases substantially all of the coal it mines in Wyoming and Colorado under terms set by Congress and administered by the U.S. Bureau of Land Management. These leases are generally for an initial term of ten years but may be extended by diligent development and mining of the reserve until all economically recoverable reserves are depleted. The Company has met the diligent development requirements for substantially all of these federal leases either directly through production or by including the lease as a part of a logical mining unit with other leases upon which development has occurred. Annual production on these federal leases must total at least 1.0% of the original amount of coal in the entire logical mining unit. In addition, royalties are payable

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

monthly at a rate of 12.5% of the gross realization from the sale of the coal mined using surface mining methods and at a rate of 8.0% of the gross realization for coal produced using underground mining methods. The Company also leases coal reserves in Arizona from The Navajo Nation and the Hopi Tribe under leases that are administered by the U.S. Department of the Interior. These leases expire upon exhaustion of the leased reserves or upon the permanent ceasing of all mining activities on the related reserves as a whole. The royalty rates are also generally based upon a percentage of the gross realization from the sale of coal. These rates are subject to redetermination every ten years under the terms of the leases. The remainder of the leased coal is generally leased from state governments, land holding companies and various individuals. The duration of these leases varies greatly. Typically, the lease terms are automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

Future minimum lease and royalty payments as of December 31, 2007, are as follows:

Year Ended December 31,	Capital Leases	Operating Leases	Coal Reserves
	(Dollars in thousands)		
2008	$ 17,349	$ 85,356	$ 187,946
2009	19,141	66,037	132,060
2010	15,117	54,181	7,504
2011	15,117	44,661	6,638
2012	15,117	27,098	6,139
2013 and thereafter	35,020	81,712	43,129
Total minimum lease payments	$ 116,861	$ 359,045	$ 383,416
Less interest	24,675		
Present value of minimum capital lease payments	$ 92,186		

As of December 31, 2007, certain of the Company s lease obligations were secured by outstanding surety bonds and letters of credit totaling $89.9 million.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(11) Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consisted of the following:

	December 31,	
	2007	2006
	(Dollars in thousands)	
Trade accounts payable	$ 398,186	$ 369,891
Accrued taxes other than income	152,195	113,416
Accrued payroll and related benefits	76,066	109,006
Accrued health care	83,501	70,705
Workers compensation obligations	6,220	6,510
Other accrued benefits	3,103	3,148
Accrued royalties	35,367	48,879
Accrued environmental	7,093	14,390
Income taxes payable Australia	27,623	94,692
Accrued interest	30,869	38,189
Other accrued expenses	133,438	75,325
Total accounts payable and accrued expenses	$ 953,661	$ 944,151

(12) Income Taxes

Income from continuing operations before income tax provision (benefit) and minority interests consisted of the following:

	Year Ended December 31,		
	2007	2006	2005
	(Dollars in thousands)		
U.S	$ 283,501	$ 224,218	$ 171,998
Non U.S.	57,334	238,883	172,756
Total	$ 340,835	$ 463,101	$ 344,754

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Total income tax provision (benefit) consisted of the following:

	Year Ended December 31,		
	2007	2006	2005
	(Dollars in thousands)		
Current:			
U.S. federal	$	$ 4,319	$
Non U.S.	26,410	67,565	25,622
State	179	405	300
Total current	26,589	72,289	25,922
Deferred:			
U.S. federal	(141,086)	(164,768)	36,491
Non U.S.	44,142	4,094	22,997
State	(7,757)	(1,699)	(21,631)
Total deferred	(104,701)	(162,373)	37,857
Total provision (benefit)	$ (78,112)	$ (90,084)	$ 63,779

The income tax rate differed from the U.S. federal statutory rate as follows:

	Year Ended December 31,		
	2007	2006	2005
	(Dollars in thousands)		
Federal statutory rate	$ 119,292	$ 162,086	$ 120,664
Depletion	(55,279)	(52,317)	(44,228)
Foreign earnings rate differential	(13,613)	(16,649)	(12,279)
Remeasurement of foreign deferred taxes	56,029		
State income taxes, net of U.S. federal tax benefit	329	5,089	(21,436)
Deemed liquidation of subsidiary			(245,674)
Tax credits	(24,296)		
Changes in valuation allowance	(175,735)	(165,481)	216,908
Changes in tax reserves	3,256	(28,658)	44,968
Other, net	11,905	5,846	4,856
Total provision (benefit)	$ (78,112)	$ (90,084)	$ 63,779

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities consisted of the following:

	December 31,	
	2007	2006
	(Dollars in thousands)	
Deferred tax assets:		
Tax credits and loss carryforwards	$ 660,325	$ 607,717
Postretirement benefit obligations	324,660	323,058
Intangible tax asset and purchased contract rights	73,715	90,462
Accrual at spin-off for loss on firm purchase commitment	52,934	
Accrued reclamation and mine closing liabilities	15,981	5,243
Accrued long-term workers compensation liabilities	15,581	13,818
Others	85,462	83,604
Total gross deferred tax assets	1,228,658	1,123,902
Deferred tax liabilities:		
Property, plant, equipment and mine development, leased coal interests and advance royalties, principally due to differences in depreciation, depletion and asset writedowns	1,355,162	1,217,217
Others	19,054	20,256
Total gross deferred tax liabilities	1,374,216	1,237,473
Valuation allowance	(71,413)	(221,753)
Net deferred tax liability	$ (216,971)	$ (335,324)
Deferred taxes consisted of the following:		
Current deferred income taxes	$ 98,633	$ 77,562
Noncurrent deferred income taxes	(315,604)	(412,886)
Net deferred tax liability	$ (216,971)	$ (335,324)

The Company s tax credits and loss carryforwards included alternative minimum tax (AMT) and general business credits of $50.0 million and $32.2 million, U.S. net operating loss (NOL) carryforwards of $574.9 million and $535.9 million and foreign loss carryforwards of $35.4 million and $39.6 million as of December 31, 2007 and 2006, respectively. The AMT credits and foreign NOL and capital loss carryforwards have no expiration date and the U.S. NOL carryforwards begin to expire in the year 2020. The Company evaluated and assessed the expected near-term utilization of NOLs, future book and taxable income, available tax strategies and the overall deferred tax

position to determine the appropriate amount and timing of valuation allowance adjustments. This assessment resulted in a significant reduction of valuation allowance during 2007 and 2006. During 2005, the Company completed a comprehensive and strategic internal corporate restructuring project resulting in a deduction for a deemed liquidation of a subsidiary for tax purposes which significantly increased the Company s NOL s. The valuation allowance was increased during 2005 to correspond with the increase in available NOL s. The remaining valuation allowance at December 31, 2007 of $71.4 million represents a reserve for AMT credits, certain foreign deferred tax assets and state and foreign loss carryforwards, due to uncertainty of their ultimate realization.

The Company adopted the provisions of FIN No. 48 on January 1, 2007. As a result of the implementation of FIN No. 48, the Company decreased its balance of unrecognized tax benefits by $24.6 million, none

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of which was accounted for as a reduction to the Company s retained earnings balance due to a valuation allowance recorded against the Company s deferred tax asset for NOL carryforwards.

The total amount of the net unrecognized tax benefits at January 1, 2007 and December 31, 2007 was $135.0 million ($144.0 million gross) and $143.0 million ($152.6 million gross), respectively. The amount of the Company s gross unrecognized tax benefits has increased by $8.6 million since January 1, 2007. A reconciliation of the beginning and ending amount of gross unrecognized tax benefits is as follows (dollars in thousands):

Balance at January 1, 2007	$ 144,000
Additions based on tax positions related to current year	4,000
Additions for tax positions of prior years	4,600
Balance at December 31, 2007	$ 152,600

The amount of the net unrecognized tax benefits that, if recognized, would directly affect the effective tax rate is $143.0 million. However, $27.0 million would generate a deferred tax asset for state NOL carryforwards that would more likely than not be offset by a valuation allowance. The Company does not expect any significant increases or decreases to its unrecognized tax benefits within twelve months of this reporting date.

The Company recognizes interest and penalties accrued related to unrecognized tax benefits in its income tax provision. The Company has recognized $2.3 million of interest for the year ended December 31, 2007. Due to NOL carryforwards, the Company had not accrued interest for any of its unrecognized tax benefits in prior years. The Company has considered the application of penalties on its unrecognized tax benefits and determined, based upon several factors, including the existence of NOL carryforwards, that no accrual of penalties is required.

The Company s Federal income tax returns for the tax years 1999 through 2001 and 2003 through 2007 remain subject to examination by the Internal Revenue Service. The Company s state income tax returns for the tax years 1991 and beyond remain subject to examination by various state taxing authorities. The Company s foreign income tax returns for the tax years 2003 and beyond remain subject to examination by various foreign taxing authorities.

The total amount of undistributed earnings of foreign subsidiaries for income tax purposes was approximately $303.6 million and $318.9 million at December 31, 2007 and 2006, respectively. The Company has not provided deferred taxes on $264.5 million and $314.0 million of foreign earnings for 2007 and 2006, respectively, because such earnings were intended to be indefinitely reinvested outside the United States. Should the Company repatriate all of these earnings, a one-time income tax charge to the Company s consolidated results of operations of up to $92.6 million could occur.

The Company made U.S. Federal tax payments totaling $3.0 million and $3.9 million for the years ended December 31, 2007 and 2006, respectively. The Company made no U.S. Federal tax payments for the year ended December 31, 2005. The Company paid state and local income taxes totaling $1.2 million, $0.5 million and $0.3 million for the years ended December 31, 2007, 2006 and 2005, respectively. The Company made non-U.S. tax payments totaling $80.0 million, $23.1 million and $2.8 million for the years ended December 31, 2007, 2006 and

2005, respectively.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(13) Long-Term Debt

The Company s total indebtedness as of December 31, 2007 and 2006, consisted of the following:

	December 31, 2007	2006
	(Dollars in thousands)	
Term Loan under Senior Unsecured Credit Facility	$ 509,084	$ 547,000
Revolving Credit Facility	97,700	
Convertible Junior Subordinated Debentures due 2066	732,500	732,500
7.375% Senior Notes due 2016	650,000	650,000
6.875% Senior Notes due 2013	650,000	650,000
7.875% Senior Notes due 2026	246,965	246,897
5.875% Senior Notes due 2016	218,090	231,845
5.0% Subordinated Note		59,504
6.84% Series C Bonds due 2016	43,000	43,000
6.34% Series B Bonds due 2014	21,000	21,000
6.84% Series A Bonds due 2014	10,000	10,000
Capital lease obligations	92,186	96,869
Fair value of interest rate swaps	1,604	(13,784)
Other	971	2,201
Total	$ 3,273,100	$ 3,277,032

Senior Unsecured Credit Facility

On September 15, 2006, the Company entered into a Third Amended and Restated Credit Agreement (the Agreement), which established a $2.75 billion Senior Unsecured Credit Facility (the Senior Unsecured Credit Facility) and which amended and restated in full the Company s then existing $1.35 billion Senior Secured Credit Facility (the Senior Secured Credit Facility). The Senior Unsecured Credit Facility provides a $1.8 billion Revolving Credit Facility (the Revolver) and a $950.0 million Term Loan Facility (the Term Loan Facility).

The Revolver is intended to accommodate working capital needs, letters of credit, the funding of capital expenditures and other general corporate purposes. The Revolver also includes a $50.0 million sub-facility available for same-day swingline loan borrowings. As of December 31, 2007, the Company had $97.7 million borrowings and $413.5 million letters of credit outstanding under the Revolver, with a remaining available borrowing capacity of $1.29 billion.

The Term Loan Facility, which was fully drawn in October 2006 in connection with the Excel acquisition was paid down ($403.0 million) from a portion of the net proceeds from the Debentures. In conjunction with the establishment of the Senior Unsecured Credit Facility, the Company incurred $8.6 million in financing costs, of which $5.6 million related to the Revolver and $3.0 million related to the Term Loan. These debt issuance costs are being amortized to

interest expense over five years, the term of the Senior Unsecured Credit Facility.

Loans under the facility are available to the Company in U.S. dollars, with a sub-facility under the Revolver available in Australian dollars, pounds sterling and Euros. Letters of credit under the Revolver are available to the Company in U.S. dollars with a sub-facility available in Australian dollars, pounds sterling and Euros. The interest rate payable on the Revolver and the Term Loan is based on a pricing grid tied to the

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company s leverage ratio, as defined in the Agreement. The interest rate payable on the Revolver and the Term Loan is currently LIBOR plus 0.75%, which was 5.4% at December 31, 2007.

Under the Senior Unsecured Credit Facility, the Company must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio, as defined in the Agreement. The financial covenants also place limitations on the Company s investments in joint ventures, unrestricted subsidiaries, indebtedness of non-loan parties and the imposition of liens on Company assets. The new facility is less restrictive with respect to limitations on the Company s dividend payments, capital expenditures, asset sales and stock repurchases. The Senior Unsecured Credit Facility matures on September 15, 2011.

Convertible Junior Subordinated Debentures

On December 20, 2006, the Company issued $732.5 million aggregate principal amount of 4.75% Convertible Junior Subordinated Debentures due 2066 (the Debentures), including $57.5 million issued pursuant to the underwriters exercise of their over-allotment option. Net proceeds from the offering, after deducting underwriting discounts and offering expenses, were $715.0 million and were used to repay indebtedness under the Company s Senior Unsecured Credit Facility.

The Debentures will pay interest semiannually at a rate of 4.75% per year. The Company may elect to, and if and to the extent that a mandatory trigger event (as defined in the indenture governing the Debentures) has occurred and is continuing will be required to, defer interest payments on the Debentures. After five years of deferral at the Company s option, or upon the occurrence of a mandatory trigger event, the Company generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay deferred interest, subject to certain limitations. In no event may the Company defer payments of interest on the Debentures for more than 10 years.

The Debentures are convertible at any time on or prior to December 15, 2036 if any of the following conditions occur: (i) the Company s closing common stock price exceeds 140% of the then applicable conversion price for the Debentures (currently $81.83 per share) for at least 20 of the final 30 trading days in any quarter; (ii) a notice of redemption is issued with respect to the Debentures; (iii) a change of control, as defined in the indenture governing the Debentures; (iv) satisfaction of certain trading price conditions; and (v) other specified corporate transactions described in the indenture governing the Debentures. In addition, the Debentures are convertible at any time after December 15, 2036 to December 15, 2041, the scheduled maturity date. In the case of conversion following a notice of redemption or upon a non-stock change of control, as defined in the indenture governing the Debentures, holders may convert their Debentures into cash in the amount of the principal amount of their Debentures and shares of the Company s common stock for any conversion value in excess of the principal amount. In all other conversion circumstances, holders will receive perpetual preferred stock (see Note 17) with a liquidation preference equal to the principal amount of their Debentures, and any conversion value in excess of the principal amount will be settled with the Company s common stock. As a result of the Patriot Coal Corporation spin-off, the conversion rate was adjusted to 17.1078 shares of common stock per $1,000 principal amount of Debentures effective November 23, 2007. This adjusted conversion rate represents a conversion price of approximately $58.45.

The Debentures are not subject to redemption prior to December 20, 2011. Between December 20, 2011 and December 19, 2036 the Company may redeem the Debentures, in whole or in part, if for at least 20 out of the 30 consecutive trading days immediately prior to the date on which notice of redemption is given, the Company s closing

common stock price has exceeded 130% of the then applicable conversion price for the Debentures. On or after December 20, 2036, whether or not the redemption condition is satisfied, the Company may redeem the Debentures, in whole or in part. The Company may not redeem any Debentures unless (i) all accrued and unpaid interest on the Debentures has been paid in full on or prior to the redemption date and (ii) if any perpetual preferred stock is outstanding, the Company has first given notice to redeem the

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

perpetual preferred stock in the same proportion as the redemption of the Debentures. Any redemption of the Debentures will be at a cash redemption price of 100% of the principal amount of the Debentures to be redeemed, plus accrued and unpaid interest to the date of redemption.

On December 15, 2041, the scheduled maturity date, the Company will use commercially reasonable efforts, subject to the occurrence of a market disruption event, as defined in the indenture governing the Debentures, to issue securities of equivalent equity content in an amount sufficient to pay the principal amount of the Debentures, together with accrued and unpaid interest. The final maturity date of the Debentures is December 15, 2066, on which date the entire principal amount of the Debentures will mature and become due and payable, together with accrued and unpaid interest.

In connection with the issuance of the Debentures, the Company entered into a Capital Replacement Covenant (the CRC). Pursuant to the CRC, the Company covenanted for the benefit of holders of covered debt, as defined in the CRC (currently the Company s 7.875% Senior Notes due 2026, issued in the aggregate principal amount of $250.0 million), that neither the Company nor any of its subsidiaries shall repay, redeem or repurchase all or any part of the Debentures on or after December 15, 2041 and prior to December 15, 2046, except to the extent that the total repayment, redemption or repurchase price does not exceed the sum of: (i) 400% of the Company s net cash proceeds from the sale of its common stock and rights to acquire its common stock (including common stock issued pursuant to the Company s dividend reinvestment plan or employee benefit plans); (ii) the Company s net cash proceeds from the sale of its mandatorily convertible preferred stock, as defined in the CRC, or debt exchangeable for equity, as defined in the CRC; and (iii) the Company s net cash proceeds from the sale of other replacement capital securities, as defined in the CRC, in each case, during the six months prior to the notice date for the relevant payment, redemption or repurchase.

The Debentures are unsecured obligations of the Company, ranking junior to all existing and future senior and subordinated debt (excluding trade accounts payable or accrued liabilities arising in the ordinary course of business) except for any future debt that ranks equal to or junior to the Debentures. The Debentures will rank equal in right of payment with the Company s obligations to trade creditors. Substantially, all of the Company s existing indebtedness is senior to the Debentures. In addition, the Debentures will be effectively subordinated to all indebtedness of the Company s subsidiaries. The indenture governing the Debentures places no limitation on the amount of additional indebtedness that the Company or any of the Company s subsidiaries may incur.

7.375% Senior Notes Due November 2016 and 7.875% Senior Notes Due November 2026

On October 12, 2006, the Company completed a $650.0 million offering of 7.375% 10-year Senior Notes due 2016 and $250.0 million of 7.875% 20-year Senior Notes due 2026. The notes are general unsecured obligations of the Company and rank senior in right of payment to any subordinated indebtedness of the Company; equally in right of payment with any senior indebtedness of the Company; effectively junior in right of payment to the Company s existing and future secured indebtedness, to the extent of the value of the collateral securing that indebtedness; and effectively junior to all the indebtedness and other liabilities of the Company s subsidiaries that do not guarantee the notes. Interest payments are scheduled to occur on May 1 and November 1 of each year. The first interest payment occurred on May 1, 2007.

The notes are guaranteed by the Company s Subsidiary Guarantors, as defined in the note indenture. The note indenture contains covenants that, among other things, limit the Company s ability to create liens and enter into sale and lease-back transactions. The notes are redeemable at a redemption price equal to 100% of the principal amount of the notes being redeemed plus a make-whole premium, if applicable, and any accrued unpaid interest to the redemption date. Net proceeds from the offering, after deducting underwriting discounts and expenses, were $886.1 million.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6.875% Senior Notes Due March 2013

On March 21, 2003, the Company issued $650.0 million of 6.875% Senior Notes due March 2013. The notes are senior unsecured obligations of the Company and rank equally with all of the Company s other senior unsecured indebtedness. Interest payments are scheduled to occur on March 15 and September 15 of each year. The notes are guaranteed by the Company s Subsidiary Guarantors as defined in the note indenture. The note indenture contains covenants which, among other things, limit the Company s ability to incur additional indebtedness and issue preferred stock, pay dividends or make other distributions, make other restricted payments and investments, create liens, sell assets and merge or consolidate with other entities. The notes are redeemable prior to March 15, 2008, at a redemption price equal to 100% of the principal amount plus a make-whole premium (as defined in the indenture) and on or after March 15, 2008, at fixed redemption prices as set forth in the indenture.

5.875% Senior Notes Due March 2016

On March 23, 2004, the Company completed an offering of $250.0 million of 5.875% Senior Notes due March 2016. The notes are senior unsecured obligations of the Company and rank equally with all of the Company s other senior unsecured indebtedness. Interest payments are scheduled to occur on April 15 and October 15 of each year, and commenced on April 15, 2004. The notes are guaranteed by the Company s Subsidiary Guarantors as defined in the note indenture. The note indenture contains covenants which, among other things, limit the Company s ability to incur additional indebtedness and issue preferred stock, pay dividends or make other distributions, make other restricted payments and investments, create liens, sell assets and merge or consolidate with other entities. The notes are redeemable prior to April 15, 2009, at a redemption price equal to 100% of the principal amount plus a make-whole premium (as defined in the indenture) and on or after April 15, 2009, at fixed redemption prices as set forth in the indenture. Net proceeds from the offering, after deducting underwriting discounts and expenses, were $244.7 million.

5.0% Subordinated Note

The 5.0% Subordinated Note was retired during the three months ended March 31, 2007.

Series Bonds

As of December 31, 2007, the Company had $74.0 million in Series Bonds outstanding, which were assumed as part of the Excel acquisition. The 6.84% Series A Bonds have a balloon maturity in December 2014. The 6.34% Series B Bonds mature in December 2014 and are payable in installments beginning December 2008. The 6.84% Series C Bonds mature in December 2016 and are payable in installments beginning December 2012. Interest payments are scheduled to occur in June and December of each year.

Interest Rate Swaps

As of December 31, 2007, the Company had a series of fixed-to-floating interest rate swaps with a notional principal amount of $120.0 million. Under the terms of these swaps the Company receives a fixed rate of 6.875% and pays a weighted average floating rate of LIBOR plus 2.0%, which resets each March 15, June 15, September 15 and December 15. The swaps have been designated as a hedge of the changes in the fair value of the 6.875% Senior Notes due 2013.

The Company also has another series of fixed-to-floating interest rate swaps with a notional principal amount of $100.0 million. Under the terms of these swaps the Company receives a fixed rate of 5.875% and pays a weighted average floating rate of LIBOR plus 0.25%, which resets each April 15 and October 15. This series of swaps has been designated as a hedge of the changes in the fair value of the 5.875% Senior Notes due 2016.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In conjunction with the Term Loan Facility, the Company has a floating-to-fixed interest rate swap in place for a notional principal amount of $120.0 million. Under the terms of this swap the Company receives a floating rate of LIBOR plus 1.0% and pays a fixed rate of 6.25%. This interest rate swap was designated as a hedge of the variable interest payments on the Term Loan under the Senior Unsecured Credit Facility.

Because the critical terms of the swaps and the respective debt instruments they hedge coincide, there was no hedge ineffectiveness recognized in the consolidated statements of operations during the years ended December 31, 2007 and 2006. At December 31, 2007 and 2006 there was an unrealized loss related to the cash flow hedge of $6.8 million and $2.5 million, respectively. At December 31, 2007 there was a net unrealized gain on the fair value hedges of $1.6 million. At December 31, 2006 there was a net unrealized loss on the fair value hedges of $13.8 million. The fair value hedge is reflected as an adjustment to the carrying value of the Senior Notes (see table above).

Capital Lease Obligations and Other

Capital lease obligations include obligations assumed from the Excel acquisition, primarily for mining equipment (see Note 10 for additional information on the Company s capital lease obligations).

Other long-term debt, which consists principally of notes payable, is due in installments through 2016. The weighted-average effective interest rate of this debt was 6.32% as of December 31, 2007.

As of December 31, 2006, Capital lease obligations reflected an additional $40.2 million that was previously classified as Accounts payable and accrued expenses on the Company s consolidated balance sheet in its Annual Report on Form 10-K for the year ended December 31, 2006. The reclassification relates to a capital lease transaction structure that was finalized during the three months ended March 31, 2007. The lease term is seven years with annual payments of approximately $7.2 million over the term of the lease, and a balloon payment at maturity of approximately $11.2 million.

The aggregate amounts of long-term debt maturities subsequent to December 31, 2007, including capital lease obligations, were as follows:

Year of Maturity	**(Dollars in thousands)**
2008	$ 36,673
2009	37,395
2010	33,217
2011	546,875
2012	20,862
2013 and thereafter	2,598,078
Total	$ 3,273,100

Interest paid on long-term debt was $191.9 million, $114.6 million and $94.2 million for the years ended December 31, 2007, 2006 and 2005, respectively. The Company paid interest expense of $1.5 million and $3.3 million on the Revolver in 2007 and 2006, respectively, and no interest was paid on the Revolver in 2005.

Early Debt Extinguishment Costs

For the year ended December 31, 2007, the Company recorded net early debt extinguishment costs of $0.3 million, primarily related to the repayment of borrowings under the Term Loan Facility. For the year ended December 31, 2006, the Company recorded net early debt extinguishment costs of $1.4 million, primarily related to the repayment of borrowings on the 5.875% Senior Notes.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Shelf Registration Statement

On July 28, 2006, the Company filed an automatic shelf registration statement on Form S-3 as a well-known seasoned issuer with the SEC. The registration was for an indeterminate number of securities and is effective for three years, at which time the Company can file an automatic shelf registration statement that would become immediately effective for another three-year term. Under this universal shelf registration statement, the Company has the capacity to offer and sell from time to time securities, including common stock, preferred stock, debt securities, warrants and units. The Debentures, 7.375% Senior Notes due 2016 and 7.875% Senior Notes due 2026 were issued pursuant to the shelf registration statement.

(14) Asset Retirement Obligations

Reconciliations of the Company s liability for asset retirement obligations were as follows:

	December 31,	
	2007	2006
	(Dollars in thousands)	
Balance at beginning of year, including discontinued operations	$ 423,031	$ 399,203
Liabilities incurred or acquired	27,041	18,573
Liabilities settled or disposed	(16,563)	(40,621)
Accretion expense	27,813	29,480
Revisions to estimate	32,142	16,396
Consolidated asset retirement obligations	493,464	423,031
Liabilities related to the Patriot spin-off	(123,917)	(139,703)
Balance at end of year	$ 369,547	$ 283,328

As of December 31, 2007, asset retirement obligations of $369.5 million consisted of $337.0 million related to locations with active mining operations and $32.5 million related to locations that are closed or inactive. As of December 31, 2006, asset retirement obligations of $423.0 million consisted of $354.0 million related to locations with active mining operations and $69.0 million related to locations that are closed or inactive. The amount of asset retirement obligations related to discontinued operations was $139.7 million at December 31, 2006. This total consists of $96.3 million related to locations with active mining operations and $43.4 million related to locations that are closed or inactive. The credit-adjusted, risk-free interest rates were 7.85% at December 31, 2007 and 6.60% and 6.16% at January 1, 2007 and 2006, respectively.

As of December 31, 2007 and 2006, the Company had $418.3 million and $356.0 million, respectively, in surety bonds outstanding to secure reclamation obligations or activities. The amount of reclamation self-bonding in certain states in which the Company qualifies was $640.6 million and $636.5 million as of December 31, 2007 and 2006, respectively. Additionally, the Company had $1.6 million and $2.7 million of letters of credit in support of

reclamation obligations or activities as of December 31, 2007 and 2006, respectively. These figures have all been adjusted to exclude financial guarantees related to Patriot Coal Corporation.

(15) Pension and Savings Plans

One of the Company s subsidiaries, Peabody Investments Corp., sponsors a defined benefit pension plan covering certain U.S. salaried employees and eligible hourly employees at certain Peabody Investments Corp. subsidiaries (the Peabody Plan). A Peabody Investments Corp. subsidiary also has a defined benefit pension plan covering eligible employees who are represented by the UMWA under the Western Surface Agreement (the Western Plan). Peabody Investments Corp. also sponsors an unfunded supplemental retirement plan to provide senior management with benefits in excess of limits under the federal tax law.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Annual contributions to the plans are made as determined by consulting actuaries based upon the Employee Retirement Income Security Act of 1974 minimum funding standard. In May 1998, the Company entered into an agreement with the Pension Benefit Guaranty Corporation (PBGC) which requires the Company to maintain certain minimum funding requirements. Beginning on January 1, 2008, new minimum funding standards will be required by the Pension Protection Act of 2006. Assets of the plans are primarily invested in various marketable securities, including U.S. government bonds, corporate obligations and listed stocks.

Net periodic pension costs included the following components:

	Year Ended December 31,		
	2007	2006	2005
	(Dollars in thousands)		
Service cost for benefits earned	$ 12,719	$ 12,234	$ 11,853
Interest cost on projected benefit obligation	48,959	46,034	45,499
Expected return on plan assets	(57,370)	(54,587)	(52,812)
Amortization of prior service cost	349	(32)	
Amortization of actuarial losses	15,329	22,685	24,588
Net periodic pension costs	19,986	26,334	29,128
Curtailment (gain) loss	(403)		9,527
Total net periodic pension costs	$ 19,583	$ 26,334	$ 38,655

During 2007, benefits were frozen for certain participants of the Company s Western U.S. Mining operations and those participants impacted by the Patriot spin-off under the Peabody Plan resulting in a curtailment gain of $0.4 million. The 2005 curtailment loss resulted from the termination of operations at two of the three operating mines that participate in the Western Plan during 2005. The loss is actuarially determined and consists of an increase in the actuarial liability, the accelerated recognition of previously unamortized prior service cost and contractual termination benefits under the Western Plan resulting from the termination of operations.

The following includes amounts recognized in accumulated other comprehensive income:

	Year Ended December 31, 2007 (Dollars in thousands)
Net actuarial gain arising during year	$ (89,628)
Prior service cost arising during year	7,893
Amortizations:	
Actuarial loss	(15,329)

Prior service credit		54
Total recognized in other comprehensive income		(97,010)
Net periodic postretirement benefit costs		19,986
Total recognized in net periodic postretirement benefit costs and other comprehensive income	$	(77,024)

The Company amortizes actuarial gains and losses using a 5% corridor with a five-year amortization period. The estimated net actuarial gain and prior service cost that will be amortized from accumulated other comprehensive income (loss) into net periodic pension costs during the year ended December 31, 2008 are $0.5 million and $1.2 million, respectively.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following summarizes the change in benefit obligation, change in plan assets and funded status of the Company s plans:

	December 31, 2007	2006
	(Dollars in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of period	$ 832,800	$ 801,818
Service cost	12,719	12,234
Interest cost	48,959	46,034
Plan amendments	7,893	
Curtailments	(20,516)	
Benefits paid	(42,642)	(40,323)
Actuarial (gain) loss	(61,063)	13,037
Projected benefit obligation at end of period	778,150	832,800
Change in plan assets:		
Fair value of plan assets at beginning of period	704,172	654,023
Actual return on plan assets	65,417	84,326
Employer contributions	5,357	6,146
Benefits paid	(42,642)	(40,323)
Fair value of plan assets at end of period	732,304	704,172
Funded status at end of year	$ (45,846)	$ (128,628)
Amounts recognized in the consolidated balance sheets:		
Intangible asset (included in Investments and other assets)	$ 208	$
Current obligation (included in Accounts payable and accrued expenses)	(1,315)	(1,312)
Noncurrent obligation (included in Other noncurrent liabilities)	(44,739)	(127,316)
Net amount recognized	$ (45,846)	$ (128,628)

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	December 31,	
	2007	2006

Discount rate	6.75%	6.00%
Rate of compensation increase	N/A	3.50%
Measurement date	December 31, 2007	December 31, 2006

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The weighted-average assumptions used to determine net periodic benefit cost were as follows:

	Year Ended December 31,		
	2007	**2006**	**2005**
Discount rate	6.00%	5.90%	6.10%
Expected long-term return on plan assets	8.75%	8.75%	8.75%
Rate of compensation increase	3.50%	3.50%	3.50%
Measurement date	December 31, 2006	December 31, 2005	December 31, 2004

The expected rate of return on plan assets is determined by taking into consideration expected long-term returns associated with each major asset class (net of inflation) based on long-term historical ranges, inflation assumptions and the expected net value from active management of the assets based on actual results.

The projected benefit obligation and the accumulated benefit obligation exceeded plan assets for all plans as of December 31, 2007 and 2006. The accumulated benefit obligation for all pension plans was $681.1 million and $808.4 million as of December 31, 2007, and 2006, respectively.

Plan Assets

Assets of the Peabody Plan and the Western Plan are commingled in the Peabody Investment Corporation Master Trust (the Master Trust) and are invested in accordance with investment guidelines that have been established by the Company s Retirement Committee (the Retirement Committee) after consultation with outside investment advisors and actuaries.

As of the year ended December 31, 2007, Master Trust assets totaled $732.3 million and were invested in the following major asset categories:

	Percentage Allocation of Total Assets	**Target Allocation**
Equity securities	38.5%	40.0%
Fixed income	36.6%	35.0%
International equity	15.5%	15.0%
Real estate	9.4%	10.0%
Total	100.0%	100.0%

As of the year ended December 31, 2006, Master Trust assets totaled $704.2 million and were invested in the following major asset categories:

	Percentage Allocation of Total Assets	Target Allocation
Equity securities	58.5%	55.0%
Fixed income	32.9%	35.0%
Real estate	7.6%	10.0%
Cash fund	1.0%	0.0%
Total	100.0%	100.0%

The asset allocation targets have been set with the expectation that the plan s assets will fund the plan s expected liabilities with an appropriate level of risk. To determine the appropriate target asset allocations, the Retirement Committee considers the demographics of the plan participants, the funding status of the plan, the

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

business and financial profile of the Company and other associated risk preferences. These allocation targets are reviewed by the Retirement Committee on a regular basis and revised as necessary. Periodically, assets are rebalanced among major asset categories to maintain the allocations within a range of plus or minus 5% of the target allocation.

Plan assets are either under active management by third-party investment advisors or in index funds, all selected and monitored by the Retirement Committee. The Retirement Committee has established specific investment guidelines for each major asset class including performance benchmarks, allowable and prohibited investment types and concentration limits. In general, the plan investment guidelines do not permit leveraging the Master Trust s assets. Equity investment guidelines do not permit entering into put or call options (except as deemed appropriate to manage currency risk), and futures contracts are permitted only to the extent necessary to equitize cash holdings.

Contributions

The Company expects to contribute $19.7 million to its funded pension plans and make $1.3 million in expected benefit payments attributable to its unfunded pension plans during 2008.

Estimated Future Benefit Payments

The following benefit payments (net of retiree contributions), which reflect expected future service, as appropriate, are expected to be paid by the Master Trust:

	Pension Benefits (Dollars in thousands)
2008	$ 45,287
2009	46,575
2010	48,084
2011	50,211
2012	52,010
Years 2013-2017	321,112

Defined Contribution Plans

The Company sponsors employee retirement accounts under three 401(k) plans for eligible salaried U.S. employees. The Company matches voluntary contributions to each plan up to specified levels. Excluding the discontinued operations of Patriot, the expense for these plans was $21.7 million, $12.7 million and $9.5 million for the years ended December 31, 2007, 2006 and 2005, respectively. A performance contribution feature allows for additional contributions from the Company based upon meeting specified Company performance targets, and the performance contributions made by the Company were $4.9 million, $7.3 million and $8.7 million for the years ended December 31, 2007, 2006 and 2005, respectively, excluding the discontinued operations of Patriot.

Multi-Employer Pension Plan Discontinued Operations

Certain subsidiaries that were part of the Patriot spin-off participate in multi-employer pension plans (the 1950 Plan and the 1974 Plan), which provide defined benefits to substantially all hourly coal production workers represented by the UMWA under the 2007 NBCWA. During 2007, contributions of $5.9 million made to the 1974 Plan were expensed as paid, and are reflected in Discontinued operations. There were no contributions to the multi-employer pension plans during the years ended December 31, 2006 or 2005.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(16) Postretirement Health Care and Life Insurance Benefits

The Company currently provides health care and life insurance benefits to qualifying salaried and hourly retirees and their dependents from defined benefit plans established by the Company. Plan coverage for health and life insurance benefits is provided to future hourly retirees in accordance with the applicable labor agreement.

Net periodic postretirement benefit costs included the following components:

	Year Ended December 31,		
	2007	2006	2005
	(Dollars in thousands)		
Service cost for benefits earned	$ 9,427	$ 7,575	$ 4,812
Interest cost on accumulated postretirement benefit obligation	50,542	43,497	45,108
Amortization of prior service cost	(158)	(2,232)	(2,667)
Amortization of actuarial losses	22,788	18,123	16,318
Net periodic postretirement benefit costs	$ 82,599	$ 66,963	$ 63,571

Net periodic postretirement benefit costs related to the spin-off of Patriot for the years ended December 31, 2007, 2006, and 2005, were $46.6 million, $41.4 million, and $35.4 million, respectively, and were included in Discontinued operations. The Company amortizes actuarial gains and losses using a 0% corridor with an amortization period that covers the average remaining service period of active employees (8.92 years and 8.47 years at January 1, 2007 and 2006, respectively).

The following includes amounts recognized in accumulated other comprehensive income:

	Year Ended December 31, 2007 (Dollars in thousands)
Net actuarial gain arising during year	$ (24,474)
Prior service cost arising during year	13,835
Amortizations:	
Actuarial loss	(22,788)
Prior service credit	158
Total recognized in other comprehensive income	(33,269)
Net periodic postretirement benefit costs	82,599
	$ 49,330

Total recognized in net periodic postretirement benefit costs and other comprehensive income

The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive income (loss) into net periodic postretirement benefit costs during the year ended December 31, 2008 are $18.0 million and $0.4 million, respectively.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the plans combined funded status reconciled with the amounts shown in the consolidated balance sheets:

	December 31, 2007	2006
	(Dollars in thousands)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of period	$ 872,732	$ 765,928
Service cost	9,427	7,575
Interest cost	50,542	43,497
Participant contributions	883	1,082
Plan amendments	13,835	15,878
Benefits paid	(67,168)	(68,475)
Actuarial (gain) loss	(24,474)	107,247
Accumulated postretirement benefit obligation at end of period	855,777	872,732
Change in plan assets:		
Fair value of plan assets at beginning of period		
Employer contributions	66,285	67,393
Participant contributions	883	1,082
Benefits paid and administrative fees (net of Medicare Part D reimbursements)	(67,168)	(68,475)
Fair value of plan assets at end of period		
Funded status at end of year	(855,777)	(872,732)
Less current portion (included in Accounts payable and accrued expenses)	70,069	63,719
Noncurrent obligation (included in Accrued postretirement benefit costs)	$ (785,708)	$ (809,013)

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	December 31, 2007	2006
Discount rate	6.60%	6.00%
Rate of compensation increase	3.50%	3.50%
Measurement date	December 31, 2007	December 31, 2006

The weighted-average assumptions used to determine net periodic benefit cost were as follows:

	Year Ended December 31,		
	2007	**2006**	**2005**
Discount rate	6.00%	5.90%	6.10%
Rate of compensation increase	3.50%	3.50%	3.50%
Measurement date	December 31, 2006	December 31, 2005	December 31, 2004

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following presents information about the assumed health care cost trend rate:

	Year Ended December 31,	
	2007	2006
Health care cost trend rate assumed for next year	7.50%	7.50%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.75%	4.75%
Year that the rate reaches the ultimate trend rate	2013	2012

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

	One Percentage-Point Increase	One Percentage-Point Decrease
	(Dollars in thousands)	
Effect on total service and interest cost components	$ 11,202	$ (9,580)
Effect on total postretirement benefit obligation	$ 81,535	$ (70,842)

Plan Assets

The Company s postretirement benefit plans are unfunded.

Estimated Future Benefit Payments

The following benefit payments (net of retiree contributions), which reflect expected future service, as appropriate, are expected to be paid by the Company:

	Postretirement Benefits (Dollars in thousands)
2008	$ 70,069
2009	71,115
2010	72,391
2011	73,755
2012	76,752
Years 2013-2017	378,227

Medicare and Other Plan Changes

Effective November 15, 2006, the medical premium reimbursement plan was changed for salaried employees who retired after December 31, 2004. The plan change did not apply to Powder River or Lee Ranch employees. The amendment resulted in a $20.6 million increase to the retiree health care liability. The Company began recognizing the effect of the plan amendment over 10.25 years beginning November 15, 2006. The effect was $2.0 million and $0.3 million for the years ended December 31, 2007 and 2006, respectively.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Company elected not to defer the effects of the Act as discussed in FASB Staff Position 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. Additionally, the Company did not elect the federal subsidy provisions of the Act; rather the Company coordinated benefits with available Medicare coverage considered the primary payer, whether or not the beneficiary enrolled and paid the required premiums.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company recognized a reduction in the benefit obligation on two distinct components. For plans that required amendment to incorporate the Act, the Company recognized a liability reduction of $19.1 million. This reduction was treated as a negative plan amendment and is being amortized to income over six years beginning December 15, 2003. For plans that did not require amendment, the Company recognized a liability reduction of $162.4 million. The reduction was treated as a change in the estimated cost to provide benefits to Medicare eligible beneficiaries constituting a component of the cumulative actuarial gain or loss subject to amortization in accordance with the Company s amortization method.

In January 1999, the Company adopted reductions to the salaried employee medical coverage levels for employees retiring before January 1, 2003, which was changed to January 1, 2005, in 2002. For employees retiring on or after January 1, 2005, the previous medical plan was replaced with a medical premium reimbursement plan. This plan change did not apply to Powder River or Lee Ranch salaried employees. The change in the retiree health care plan resulted in a $22.4 million reduction to the salaried retiree health care liability. The Company began recognizing the effect of the plan amendment over nine years beginning January 1, 1999. The effect was $1.0 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Multi-Employer Benefit Plans Discontinued Operations

Multi-employer benefit obligations related to the Combined Fund, the 1992 Benefit Plan and 1993 Benefit Plan became the responsibility of Patriot in conjunction with the spin-off. The Surface Mining Control and Reclamation Act Amendments of 2006 amended the federal laws establishing the Combined Fund and the 1992 Benefit Plan and include the 1993 Benefit Plan. To the extent that (i) the annual federal funding exceeds a specified amount, (ii) Congress does not allocate additional funds to cover the shortfall and (iii) Patriot s subsidiaries do not pay for their share of the shortfall, some of the Company s subsidiaries would be responsible for the additional costs.

As of December 31, 2006, the $25.6 million noncurrent obligation for the Combined Fund was in Noncurrent liabilities of discontinued operations and the current portion of $5.2 million was in Current liabilities of discontinued operations in the consolidated balance sheets. The total expense for the Combined Fund, the 1992 Benefit Plan and 1993 Benefit Plan was $14.5 million, $8.2 million and $4.9 million for the years ended December 31, 2007, 2006 and 2005, respectively, and was included in Discontinued operations.

Pursuant to the provisions of the Coal Act and the 1992 Benefit Plan, the Company was required to provide a specified amount of security. In accordance with the 1992 Benefit Plan, the Company had outstanding letters of credit of $41.4 million as of October 31, 2007 and $119.4 million as of December 31, 2006, to secure the Company s obligation.

(17) Stockholders Equity

Common Stock

The Company has 800.0 million authorized shares of $0.01 par value common stock. Holders of common stock are entitled to one vote per share on all matters to be voted upon by the stockholders. The holders of common stock do not have cumulative voting rights in the election of directors. Holders of common stock are entitled to receive ratably dividends if, as and when dividends are declared from time to time by the Board of Directors out of funds legally

available for that purpose, after payment of dividends required to be paid on outstanding preferred stock or series common stock. Upon liquidation, dissolution or winding up, any business combination or a sale or disposition of all or substantially all of the assets, the holders of common stock are entitled to receive ratably the assets available for distribution to the stockholders after payment of liabilities and accrued but unpaid dividends and liquidation preferences on any outstanding preferred stock or series common stock. The common stock has no preemptive or conversion rights and is not subject to further calls

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

or assessment by the Company. There are no redemption or sinking fund provisions applicable to the common stock.

Effective February 22, 2006, the Company implemented a two-for-one stock split on all shares of its common stock. The Company had a similar two-for-one stock split on March 30, 2005. All share and per share amounts in these consolidated financial statements and related notes reflect the stock splits.

The following table summarizes common stock activity from December 31, 2004 to December 31, 2007:

	Shares Outstanding
December 31, 2004	**259,135,908**
Stock options exercised	3,633,750
Stock grants to employees	375,400
Employee stock purchases	210,750
Stock grants to non-employee directors	1,594
December 31, 2005	**263,357,402**
Stock options exercised	1,940,539
Stock grants to employees	566,631
Employee stock purchases	156,785
Stock grants to non-employee directors	10,440
Shares repurchased	(2,184,958)
December 31, 2006	**263,846,839**
Stock options exercised	5,222,074
Stock grants to employees	937,795
Employee stock purchases	185,646
Stock grants to non-employee directors	11,892
Shares relinquished	(137,625)
December 31, 2007	**270,066,621**

Preferred Stock and Series Common Stock

In addition to the common stock, the Board of Directors is authorized to issue up to 10.0 million shares of preferred stock and up to 40.0 million shares of series common stock. The Board of Directors is authorized to determine the terms and rights of each series, including the number of authorized shares, whether dividends (if any) will be cumulative or non-cumulative and the dividend rate of the series, redemption or sinking fund provisions, conversion terms, prices and rates, and amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company. The Board of Directors may also determine restrictions on the issuance of shares of the same series or of any other class or series, and the voting rights (if any) of

the holders of the series. There were no outstanding shares of preferred stock or series common stock as of December 31, 2007.

Perpetual Preferred Stock

As discussed in Note 13, the Company issued $732.5 million aggregate principal amount of Debentures on December 20, 2006. Perpetual preferred stock issued upon a conversion of Debentures will be fully paid and non-assessable, and holders will have no preemptive or preferential right to purchase any of the Company s other securities. The perpetual preferred stock has a liquidation preference of $1,000 per share, is

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

not convertible and is redeemable at the Company s option at any time at a cash redemption price per share equal to the liquidation preference plus any accumulated dividends. Holders are entitled to receive cumulative dividends at an annual rate of 3.0875% if and when declared by the Company s Board of Directors. After the Company has failed to pay dividends on the perpetual preferred stock for five years, or upon the occurrence of a mandatory trigger event, as defined in the certificate of designations governing the perpetual preferred stock, the Company generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay accumulated dividends after the payment in full of any deferred interest on the Debentures, subject to certain limitations. In the event of a mandatory trigger event, the Company may not declare dividends on the perpetual preferred stock other than those funded through the sale of warrants or preferred stock as described above. Any deferred interest on the Debentures at the time of notice of conversion will be reflected as accumulated dividends on the perpetual preferred stock at issuance. Additionally, holders of the perpetual preferred stock are entitled to elect two additional members to serve on the Company s Board of Directors if (i) prior to any remarketing of the perpetual preferred stock, the Company fails to declare and pay dividends with respect to the perpetual stock for 10 consecutive years or (ii) after any successful remarketing or any final failed remarketing of the perpetual preferred stock, the Company fails to declare and pay six dividends thereon, whether or not consecutive. The perpetual preferred stock may be remarketed at the holder s election after December 15, 2046 or earlier, upon the first occurrence of a change of control if the Company does not redeem the perpetual preferred stock. There were no outstanding shares of perpetual preferred stock as of December 31, 2007.

Preferred Share Purchase Rights Plan and Series A Junior Participating Preferred Stock

Each outstanding share of common stock, par value $0.01 per share, of the Company carries one preferred share purchase right (a Right). The Rights are governed by a plan that expires in August 2012.

The Rights have certain anti-takeover effects. The Rights will cause substantial dilution to a person or group that attempts to acquire the Company on terms not approved by the Company s Board of Directors, except pursuant to any offer conditioned on a substantial number of Rights being acquired. The Rights should not interfere with any merger or other business combination approved by the Board of Directors since the Rights may be redeemed by the Company at a redemption price of $0.001 per Right prior to the time that a person or group has acquired beneficial ownership of 15% or more of the common stock of the Company. In addition, the Board of Directors is authorized to reduce the 15% threshold to not less than 10%.

Each Right entitles the holder to purchase one quarter of one-hundredth of a share of series A junior participating preferred stock from the Company at an exercise price of $27.50, which in turn provides rights to receive the number of common stock shares having a market value of two times the exercise price of the Right. The Right is exercisable only if a person or group acquires 15% or more of the Company s common stock. The Board of Directors is authorized to issue up to 1.5 million shares of series A junior participating preferred stock. There were no outstanding shares of series A junior participating preferred stock as of December 31, 2007.

Treasury Stock

In July 2005, the Company s Board of Directors authorized a share repurchase program of up to 5% of the then outstanding shares of its common stock, or approximately 13.1 million shares. The repurchases may be made from time to time based on an evaluation of the Company s outlook and general business conditions, as well as alternative

investment and debt repayment options. During the year ended December 31, 2006, the Company repurchased 2,184,958 of its common shares at a cost of $99.8 million. There were no share repurchases under this program for the year ended December 31, 2007.

During the year ended December 31, 2007, the Company received 137,625 shares of common stock as consideration for employees exercise of stock options and to pay estimated taxes at the vesting date of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

restricted stock. The value of the common stock tendered by employees to exercise stock options and to settle taxes on restricted stock was based upon the closing price on the dates of the respective transactions. The common stock tenders were in accordance with the provisions of the 1998 Stock Purchase and Option Plan, which was previously approved by the Company s Board of Directors.

(18) Share-Based Compensation

The Company recognizes share-based compensation expense in accordance with SFAS No. 123(R), which it adopted on January 1, 2006, and utilizes restricted stock, nonqualified stock options, performance units, and an employee stock purchase plan as part of its share-based compensation program. The Company has four equity incentive plans for employees and non-employee directors that in the aggregate allow for the issuance of share-based compensation in the form of stock appreciation rights, restricted stock, performance awards, incentive stock options, nonqualified stock options and stock units. Members of the Company s Board of Directors are eligible for stock option and restricted stock grants at the date of their election and annually in January. These plans made 47.4 million shares of the Company s common stock available for grant, with 13.6 million shares available for grant as of December 31, 2007. Additionally, in 2001, the Company established an employee stock purchase plan that provided for the purchase of up to 6.0 million shares of the Company s common stock.

For share-based payment instruments excluding restricted stock, the Company recognized $6.6 million (or $0.02 per diluted share), $17.7 million (or $0.07 per diluted share) and $24.8 million (or $0.09 per diluted share) of expense, net of taxes, for the years ended December 31, 2007, 2006 and 2005, respectively. Share-based compensation expense is recorded in Selling and administrative expenses in the consolidated statements of operations. As of December 31, 2007, the total unrecognized compensation cost related to nonvested awards was $26.9 million, net of taxes, which is expected to be recognized over 5.2 years with a weighted-average period of 1.1 years.

The Company used the Black-Scholes option pricing model to determine the fair value of stock options and employee stock purchase plan share-based payments made before and after the adoption of SFAS No. 123(R). The Company utilized U.S. Treasury yields as of the grant date for its risk-free interest rate assumption, matching the treasury yield terms to the expected life of the option or vesting period of the performance unit awards. The Company utilized historical company data to develop its dividend yield, expected volatility and expected option life assumptions.

Restricted Stock Awards

The Company began utilizing restricted stock as part of its equity-based compensation strategy in January 2005. Accounting for restricted stock awards was not changed by the adoption of SFAS No. 123(R). The Company recognized $10.6 million, $4.2 million and $0.9 million of expense, net of taxes, for the years ended December 31, 2007, 2006 and 2005, respectively, related to restricted stock.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of restricted stock award activity is as follows:

	Year Ended December 31, 2007	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2007	1,011,577	$ 33.32
Granted	1,020,809	42.16
Vested	(38,607)	27.12
Acceleration at spin-off	(389,798)	47.55
Forfeited	(71,122)	32.79
Nonvested at December 31, 2007	1,532,859	$ 36.01

Stock Options

Employee and director stock options granted since the Company s initial public offering (IPO) of common stock in May 2001 generally vest ratably over three years and expire after 10 years from the date of the grant, subject to earlier termination upon discontinuation of an employee s service. Options granted prior to the IPO generally cliff vest in 2010 and represented 1.2 million options of the 4.8 million options outstanding at December 31, 2007. Option grants are typically made in January of each year or following the inception of employment for employees hired during the year who are eligible to participate in the plan. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The Company recognized expense, net of taxes, of $3.7 million, $4.7 million and $0.1 million for the years ended December 31, 2007, 2006 and 2005, respectively, related to stock option grants to employees and non-employee directors.

A summary of outstanding option activity under the plans is as follows:

	Year Ended December 31, 2007	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value (in millions)
Beginning balance	9,320,718	$ 8.16		
Granted	427,298	35.05		
Spin-off adjustment	349,108			
Exercised	(5,222,074)	4.86		
Forfeited	(70,116)	3.86		

Outstanding	4,804,934	$	12.46	4.8	$	236.3
Vested and Exercisable	2,626,802	$	8.95	4.5	$	138.4

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the years ended December 31, 2007, 2006 and 2005, the total intrinsic value of options exercised, defined as the excess fair value of the underlying stock over the exercise price of the options, was $248.7 million, $84.2 million and $77.6 million, respectively. The weighted-average fair values of the Company s stock options and the assumptions used in applying the Black-Scholes option pricing model (for grants during the years ended December 31, 2007, 2006 and 2005) were as follows:

	December 31,		
	2007	**2006**	**2005**
Weighted-average fair value	$ 37.93	$ 16.52	$ 8.03
Risk-free interest rate	4.6%	4.3%	3.6%
Expected option life	5.0 years	6.0 years	5.7 years
Expected volatility	43%	36%	40%
Dividend yield	0.6%	0.8%	1.0%

Prior to adopting SFAS No. 123(R), the Company applied APB Opinion No. 25 and related interpretations to account for its equity incentive plans. The following table reflects 2005 pro forma net income and basic and diluted earnings per share had compensation cost been determined for the Company s non-qualified and incentive stock options based on the fair value at the grant dates consistent with the methodology set forth under SFAS No. 123:

	Year Ended December 31, 2005 (Dollars in thousands except per share data)
Net income:	
As reported	$ 422,653
Pro forma	418,704
Basic earnings per share:	
As reported	$ 1.62
Pro forma	1.60
Diluted earnings per share:	
As reported	$ 1.58
Pro forma	1.56

Performance Units

Performance units, which are typically granted annually in January, and vest over a three-year measurement period, subject to the achievement of performance goals and relative stock price performance at the conclusion of the vesting term. Three performance unit grants were outstanding during 2007 (the 2005, 2006 and 2007 grants), 2006 (the 2004, 2005 and 2006 grants) and 2005 (the 2003, 2004 and 2005 grants). The payouts related to all active grants will be settled in the Company s common stock. The payouts for the 2004 and 2003 grants were settled in cash. Payouts for

the 2004 through 2007 grants are based 50% on stock price performance compared to both an industry peer group and a S&P index (a market condition under SFAS No. 123(R)) and 50% on a return on capital target (a performance condition under SFAS No. 123(R)). The payout related to the 2003 grant was based on the Company s stock price performance relative to both an industry peer group and an S&P index. The Company granted 0.2 million performance units in each of the years ended December 31, 2007, 2006, and 2005.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of performance unit activity is as follows:

	Year Ended December 31, 2007	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Contractual Life
Nonvested at January 1, 2007	421,421	$ 35.24	
Granted	180,462	42.33	
Spin-off adjustment	49,689		
Vested	(305,864)	38.32	
Nonvested at December 31, 2007	345,708	$ 41.53	1.5

As of December 31, 2007, there were 305,864 performance units vested that had an aggregate intrinsic value of $25.8 million and a conversion price per share of $59.31.

Under APB Opinion No. 25, all performance unit awards were accounted for as variable awards. Under SFAS No. 123(R), the awards settled in cash were accounted for as liability awards and adjusted to fair value at each period-end, and the awards settled in common stock are accounted for based on their grant date fair value. The performance condition awards were valued utilizing the grant date fair values of the Company s stock adjusted for dividends foregone during the vesting period. The market condition awards were valued utilizing a Monte Carlo simulation which incorporates the total shareholder return hurdles set for each grant. The Company recognized expense, net of taxes, of $1.6 million, $11.7 million, and $24.7 million for the years ended December 31, 2007, 2006, and 2005, respectively, related to performance units. The assumptions used in the valuations for grants during the years ended December 31, 2007 and 2006 were as follows:

	December 31, 2007	2006
Risk-free interest rate	4.7%	4.3%
Expected volatility	43%	36%
Dividend yield	0.6%	0.8%

Employee Stock Purchase Plan

Based on the Company s employee stock purchase plan, eligible full-time and part-time employees are able to contribute up to 15% of their base compensation into this plan, subject to a limit of $25,000 per person per year. Employees are able to purchase Company common stock at a 15% discount to the lower of the fair market value of the Company s common stock on the initial or final trading dates of each six-month offering period. Offering periods

begin on January 1 and July 1 of each year. The fair value of the six-month look-back option in the Company s employee stock purchase plan is estimated by adding the fair value of 0.15 of one share of stock to the fair value of 0.85 of an option on one share of stock. The Company recognized expense, net of taxes, of $1.2 million for the year ended December 31, 2007 related to its employee stock purchase plan. Shares purchased under the plan were 0.2 million for each of the years ended December 31, 2007, 2006 and 2005, respectively.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(19) Accumulated Other Comprehensive Income (Loss)

The following table sets forth the after-tax components of comprehensive income (loss):

	Foreign Currency Translation Adjustment	Minimum Pension Liability Adjustment	Net Actuarial Loss Associated with Postretirement Plans and Workers Compensation Obligations	Prior Service Cost Associated with Postretirement Plans	Cash Flow Hedges	Total Accumulated Other Comprehensive Loss
			(Dollars in thousands)			
December 31, 2004	$ 3,153	$ (71,645)	$	$	$ 7,874	$ (60,618)
Net increase in value of cash flow hedges					36,154	36,154
Reclassification from other comprehensive income to earnings					(24,733)	(24,733)
Current period change		2,402				2,402
December 31, 2005	$ 3,153	$ (69,243)	$	$	$ 19,295	$ (46,795)
Net increase in value of cash flow hedges					45,799	45,799
Reclassification from other comprehensive income to earnings					(21,452)	(21,452)
Current period change		22,377				22,377
Adjustment to initially apply SFAS No. 158		46,866	(288,820)	(7,033)		(248,987)
December 31, 2006	$ 3,153	$	$ (288,820)	$ (7,033)	$ 43,642	$ (249,058)
Net increase in value of cash flow hedges					83,606	83,606
Reclassification from other comprehensive income to earnings:						

Continuing operations			24,329	(127)	(61,810)	(37,608)
Discontinued operations			17,937	(6,074)		11,863
Current period change			64,183	(13,037)		51,146
Patriot spin-off			65,644	7,341		72,985
December 31, 2007	$ 3,153	$	$ (116,727)	$ (18,930)	$ 65,438	$ (67,066)

Comprehensive income differs from net income by the amount of unrealized gain or loss resulting from valuation changes of the Company s cash flow hedges (which include fuel and natural gas hedges, currency forwards and interest rate swaps) during the periods, and for the year ended December 31, 2007, the adjustment required by SFAS No. 158 to record the funded status of the Company s pension and other post-retirement benefit plans. The values of the Company s cash flow hedging instruments are affected by changes in interest rates, crude oil, heating oil and natural gas prices and the U.S. dollar/Australian dollar exchange rate.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(20) Guarantees and Financial Instruments With Off-Balance-Sheet Risk

In the normal course of business, the Company is a party to guarantees and financial instruments with off-balance-sheet risk, such as bank letters of credit, performance or surety bonds and other guarantees and indemnities, which are not reflected in the accompanying consolidated balance sheets. Such financial instruments are valued based on the amount of exposure under the instrument and the likelihood of required performance. In the Company s past experience, virtually no claims have been made against these financial instruments. Management does not expect any material losses to result from these guarantees or off-balance-sheet instruments.

Letters of Credit and Bonding

The Company has letters of credit, surety bonds and corporate guarantees (such as self bonds) in support of the Company s reclamation, lease, workers compensation, retiree healthcare and other obligations as follows as of December 31, 2007:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Retiree Healthcare Obligations	Other[1]	Total
	(Dollars in thousands)					
Self Bonding	$ 640,630	$	$	$	$	$ 640,630
Surety Bonds	418,303	72,985	31,210		16,747	539,245
Letters of Credit	1,625		102,687	41,361	267,947	413,620
	$ 1,060,558	$ 72,985	$ 133,897	$ 41,361	$ 284,694	$ 1,593,495

(1) Other includes the three letter of credit obligations described below and an additional $78.3 million in self-bonding, letters of credit and surety bonds related to collateral for surety companies, road maintenance, performance guarantees and other operations.

The Company owns a 30.0% interest in a partnership that leases a coal export terminal from the Peninsula Ports Authority of Virginia under a 30-year lease that permits the partnership to purchase the terminal at the end of the lease term for a nominal amount. The partners have severally (but not jointly) agreed to make payments under various agreements which in the aggregate provide the partnership with sufficient funds to pay rents and to cover the principal and interest payments on the floating-rate industrial revenue bonds issued by the Peninsula Ports Authority, and which are supported by letters of credit from a commercial bank. As of December 31, 2007, the Company s maximum reimbursement obligation to the commercial bank was in turn supported by a letter of credit totaling $42.8 million.

The Company is party to an agreement with the PBGC and TXU Europe Limited, an affiliate of the Company s former parent corporation, under which the Company is required to make special contributions to two of the Company s defined benefit pension plans and to maintain a $37.0 million letter of credit in favor of the PBGC. If the Company or

the PBGC gives notice of an intent to terminate one or more of the covered pension plans in which liabilities are not fully funded, or if the Company fails to maintain the letter of credit, the PBGC may draw down on the letter of credit and use the proceeds to satisfy liabilities under the Employee Retirement Income Security Act of 1974, as amended. The PBGC, however, is required to first apply amounts received from a $110.0 million guarantee in place from TXU Europe Limited in favor of the PBGC before it draws on the Company s letter of credit. On November 19, 2002 TXU Europe Limited was placed under the administration process in the United Kingdom (a process similar to bankruptcy proceedings in the United States) and continues under this process as of December 31, 2007. As a result of these proceedings, TXU Europe Limited may be liquidated or otherwise reorganized in such a way as to relieve it of its obligations under its guarantee.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2007, the Company has a $126.6 million letter of credit for collateral for bank guarantees issued with respect to certain reclamation and performance obligations related to the mines acquired in the Excel acquisition.

Other Guarantees

As part of arrangements through which the Company obtains exclusive sales representation agreements with small coal mining companies (the Counterparties), the Company issued financial guarantees on behalf of the Counterparties. These guarantees facilitate the Counterparties efforts to obtain bonding or financing. In 2007, the Company purchased approximately 345 million tons of coal reserves and surface lands in the Illinois Basin. In conjunction with this purchase, the Company agreed to provide up to $64.8 million of reclamation and bonding commitments to a third-party coal company. The Company has recognized the full amount of these commitments as a liability as of December 31, 2007. The non-cash portion of this transaction was excluded from the investing section of the statement of cash flows.

In the event of default, the Company has multiple recourse options, including the ability to assume the loans and procure title and use of the equipment purchased through the loans. If default occurs, the Company has the ability and intent to exercise its recourse options, so the liability associated with the guarantee has been valued at zero. The Company also guaranteed bonding for a partnership in which it formerly held an interest. The aggregate amount guaranteed by the Company for all such Counterparties was $8.8 million at December 31, 2007. The Company s obligations under the guarantees extend to September 2015.

The Company is the lessee under numerous equipment and property leases. It is common in such commercial lease transactions for the Company, as the lessee, to agree to indemnify the lessor for the value of the property or equipment leased, should the property be damaged or lost during the course of the Company s operations. The Company expects that losses with respect to leased property would be covered by insurance (subject to deductibles). The Company and certain of its subsidiaries have guaranteed other subsidiaries performance under their various lease obligations. Aside from indemnification of the lessor for the value of the property leased, the Company s maximum potential obligations under its leases are equal to the respective future minimum lease payments as presented in Note 10, and the Company assumes that no amounts could be recovered from third parties.

The Company s former wholly-owned subsidiary, Prairie State Generating Company, LLC (PSGC), had previously entered into a cost reimbursable Target Price Engineering, Procurement and Construction Agreement (the EPC Agreement) with Bechtel Power Corporation (Bechtel) related to the Prairie State mine mouth pulverized coal-fired generating facility. The Company provided an absolute and unconditional payment guarantee of all amounts due until financial closing by PSGC to Bechtel under the EPC Agreement (Initial Owner Guarantee). On September 28, 2007, PSGC gave Bechtel notice to proceed to full scale construction of the facility. On that date, the Company s ownership interest in PSGC was transferred to an Indiana non-profit corporation that is owned and controlled by a group of owners (Owners), including two of the Company s affiliates. Contemporaneously with the transfer of PSGC s membership interests, each Owner (including the Company s affiliates) issued a guarantee to Bechtel for its proportionate share of PSGC s obligations under the EPC Agreement and the Company issued a guarantee to Bechtel for the Company s two affiliates. The Initial Owner Guarantee was returned to the Company following the issuance of new guarantees by each Owner. After the sale of one of the Company s owner affiliates in December 2007, the Company s remaining affiliate owns 5.06% of PSGC.

The Company has provided financial guarantees under certain long-term debt agreements entered into by its subsidiaries, and substantially all of the Company s subsidiaries provide financial guarantees under long-term debt agreements entered into by the Company. The maximum amounts payable under the Company s debt agreements are equal to the respective principal and interest payments. See Note 13 for the descriptions

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the Company s (and its subsidiaries) debt. Supplemental guarantor/non-guarantor financial information is provided in Note 25.

As part of the Patriot spin-off, the Company agreed to maintain in force several letters of credit that secured Patriot obligations for certain employee benefits and workers compensation obligations. These letters of credit are to be released upon Patriot satisfying the beneficiaries with alternate letters of credit or insurance, which is expected to occur in 2008. If Patriot is unable to satisfy the primary beneficiaries by June 30, 2011, they are then required to provide directly to the Company a letter of credit in the amount of the remaining obligation. As of December 31, 2007, the amount of letters of credit securing Patriot obligations is $136.8 million.

A discussion of the Company s accounts receivable securitization is included in Note 7 to the consolidated financial statements.

(21) Fair Value of Financial Instruments

The following methods and assumptions were used by the Company in estimating its fair value disclosures for financial instruments as of December 31, 2007 and 2006:

Cash and cash equivalents, accounts receivable and accounts payable and accrued expenses have carrying values which approximate fair value due to the short maturity or the financial nature of these instruments.

The fair value of the Company s coal trading assets and liabilities was determined as described in Note 6.

Long-term debt fair value estimates are based on observed prices for securities with an active trading market when available, and otherwise on estimated borrowing rates to discount the cash flows to their present value. The 7.875% Senior Notes due 2026 and the 5.0% Subordinated Note carrying amount are net of unamortized note discount.

The fair values of interest rate swap contracts, currency forward contracts, explosives hedge contracts and fuel hedge contracts were provided by the respective contract counterparties, and were based on benchmark transactions entered into on terms substantially similar to those entered into by the Company and the contract counterparties. Based on these estimates as of December 31, 2007, the Company would have paid $1.1 million and $2.0 million, respectively, upon liquidation of its interest rate swaps and explosives hedges and would have received $124.8 million and $48.4 million, respectively, upon liquidation of its currency forwards and diesel fuel hedges.

The carrying amounts and estimated fair values of the Company s debt are summarized as follows:

	December 31, 2007		December 31, 2006	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(Dollars in thousands)			

Long-term debt	$ 3,273,100	$ 3,471,561	$ 3,277,032	$ 3,310,590

See Note 3 for a discussion of the Company s derivative financial instruments.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(22) Commitments and Contingencies

Commitments

As of December 31, 2007, purchase commitments for capital expenditures were $67.8 million. Commitments for expenditures to be made under coal leases are reflected in Note 10.

From time to time, the Company or its subsidiaries are involved in legal proceedings arising in the ordinary course of business or related to indemnities or historical operations. The Company believes it has recorded adequate reserves for these liabilities and that there is no individual case pending that is likely to have a material adverse effect on the Company s financial condition, results of operations or cash flows. The Company discusses its significant legal proceedings below.

Litigation Relating to Continuing Operations

Navajo Nation Litigation

On June 18, 1999, the Navajo Nation served three of the Company s subsidiaries, including Peabody Western Coal Company (Peabody Western), with a complaint that had been filed in the U.S. District Court for the District of Columbia. The Navajo Nation has alleged 16 claims, including Civil Racketeer Influenced and Corrupt Organizations Act (RICO) violations and fraud. The complaint alleges that the defendants jointly participated in unlawful activity to obtain favorable coal lease amendments. The plaintiff is seeking various remedies including actual damages of at least $600 million, which could be trebled under the RICO counts, punitive damages of at least $1 billion, a determination that Peabody Western s two coal leases have terminated due to Peabody Western s breach of these leases and a reformation of these leases to adjust the royalty rate to 20%. Subsequently, the court allowed the Hopi Tribe to intervene in this lawsuit and the Hopi Tribe is also seeking unspecified actual damages, punitive damages and reformation of its coal lease. One of the Company s subsidiaries named as a defendant is now a subsidiary of Patriot. However, the Company is responsible for this litigation under the Separation Agreement entered into with Patriot in connection with the spin-off. On February 9, 2005, the U.S. District Court for the District of Columbia granted a consent motion to stay the litigation until further order of the court. Peabody Western, the Navajo Nation, the Hopi Tribe and the owners of the power plants served by the suspended Black Mesa mine and the Kayenta mine have terminated the mediation with respect to this litigation and other business issues, filed a status report with the Court and asked the Court to lift the stay. The Court has not lifted the stay.

The outcome of this litigation is subject to numerous uncertainties. Based on the Company s evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, the Company believes this matter is likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

Salt River Project Agricultural Improvement and Power District Mine Closing and Retiree Health Care

Salt River Project and the other owners of the Navajo Generating Station filed a lawsuit on September 27, 1996, in the Superior Court of Maricopa County in Arizona seeking a declaratory judgment that certain costs relating to final reclamation, environmental monitoring work and mine decommissioning and costs primarily relating to retiree health

care benefits are not recoverable by the Company s subsidiary, Peabody Western, under the terms of a coal supply agreement dated February 18, 1977. The contract expires in 2011. The trial court subsequently ruled that the mine decommissioning costs were subject to arbitration but that the retiree health care costs were not subject to arbitration. The Company has recorded a receivable for mine decommissioning costs of $87.7 million and $76.8 million included in Investments and other assets in the consolidated balance sheets as of December 31, 2007 and 2006, respectively. The parties negotiated a final comprehensive settlement and are in the process of obtaining all required approvals of the settlement documents.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gulf Power Company Litigation

On June 22, 2006, Gulf Power Company filed a breach of contract lawsuit against a Company subsidiary in the U.S. District Court, Northern District of Florida, contesting the force majeure declaration by the Company subsidiary under a coal supply agreement with Gulf Power Company and seeking damages for alleged past and future tonnage shortfalls of nearly 5 million tons under the agreement, which expired on December 31, 2007. The Company has filed a motion to dismiss the Florida lawsuit or to transfer it to Illinois. The Court held an evidentiary hearing on the Company s motion to dismiss or transfer and has continued to stay discovery until the Court rules on the motion.

The outcome of this litigation is subject to numerous uncertainties. Based on the Company s evaluation of the issues and their potential impact, the amount of any future loss cannot reasonably be estimated. However, based on current information, the Company believes this matter is likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

Claims and Litigation Relating to Indemnities or Historical Operations

Oklahoma Lead Litigation

Gold Fields Mining, LLC (Gold Fields) is a dormant, non-coal producing entity that was previously managed and owned by Hanson PLC, the Company s predecessor owner. In a February 1997 spin-off, Hanson PLC transferred ownership of Gold Fields to the Company, despite the fact that Gold Fields had no ongoing operations and the Company had no prior involvement in its past operations. Gold Fields is currently one of the Company s subsidiaries. The Company indemnified TXU Group with respect to certain claims relating to a former affiliate of Gold Fields. A predecessor of Gold Fields formerly operated two lead mills near Picher, Oklahoma prior to the 1950s and mined, in accordance with lease agreements and permits, approximately 0.15% of the total amount of the crude ore mined in the county.

Gold Fields and two other companies are defendants in two class action lawsuits allegedly involving past operations near Picher, Oklahoma. The plaintiffs have asserted claims predicated on allegations of intentional lead exposure by the defendants and are seeking compensatory damages, punitive damages and the implementation of medical monitoring and relocation programs for the affected individuals. Gold Fields was also a defendant, along with other companies, in personal injury lawsuits that at one time involved over 50 individuals, arising out of the same lead mill operations. Gold Fields, along with the former affiliate, has settled most of the claims in the personal injury lawsuits and the remaining lawsuits have been dismissed with prejudice. In December 2003, the Quapaw Indian tribe and certain Quapaw land owners filed a lawsuit against Gold Fields, five other companies and the United States. The plaintiffs are seeking compensatory and punitive damages based on a variety of theories. In December 2007, the court dismissed the tribe s medical monitoring claim. Gold Fields has filed a third-party complaint against the United States and other parties. In February 2005, the state of Oklahoma on behalf of itself and several other parties sent a notice to Gold Fields and other companies regarding a possible natural resources damage claim. All of the lawsuits are pending in the U.S. District Court for the Northern District of Oklahoma.

The outcome of litigation and these claims are subject to numerous uncertainties. Based on the Company s evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, the Company believes this matter is likely to be resolved without a material adverse effect on

its financial condition, results of operations or cash flows.

Environmental Claims and Litigation

Environmental claims have been asserted against Gold Fields related to activities of Gold Fields or a former affiliate. Gold Fields or the former affiliate has been named a potentially responsible party (PRP) at five national priority list sites based on the Superfund Amendments and Reauthorization Act of 1986. Claims

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

were asserted at 12 additional sites, the total of which have since been reduced to 12 by completion of work, transfer or regulatory inactivity. The number of PRP sites in and of itself is not a relevant measure of liability, because the nature and extent of environmental concerns varies by site, as does the estimated share of responsibility for Gold Fields or the former affiliate. Undiscounted liabilities for environmental cleanup-related costs for all of the sites noted above were $42.4 million as of December 31, 2007 and $43.0 million as of December 31, 2006, $7.1 million and $14.4 million of which was reflected as a current liability, respectively. These amounts represent those costs that the Company believes are probable and reasonably estimable. In September 2005, Gold Fields and other PRPs received a letter from the U.S. Department of Justice alleging that the PRPs mining operations caused the Environmental Protection Agency (EPA) to incur approximately $125 million in residential yard remediation costs at Picher, Oklahoma and will cause the EPA to incur additional remediation costs relating to historical mining sites. Gold Fields has participated in the settlement discussions. Gold Fields believes it has meritorious defenses to these claims. Gold Fields is involved in other litigation in the Picher area, and the Company indemnified TXU Group with respect to a defendant as is more fully discussed under the Oklahoma Lead Litigation caption above. Significant uncertainty exists as to whether claims will be pursued against Gold Fields in all cases, and where they are pursued, the amount of the eventual costs and liabilities, which could be greater or less than this provision. Based on the Company s evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, the Company believes these claims and litigation are likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

Other

Certain subsidiaries of the Company are required to pay black lung excise taxes to the Federal Black Lung Trust Fund (the Trust Fund). The Trust Fund pays occupational disease benefits to entitled former miners who worked prior to July 1, 1973. Excise taxes are based on the selling price of coal, up to a maximum of $1.10 per ton for underground mines and $0.55 per ton for surface mines. The Company had a receivable for excise tax refunds paid on export shipments of $19.4 million as of December 31, 2007 and 2006. In a January 2007 decision, a federal appellate court ruled that coal companies are entitled to a refund of the Black Lung tax paid on export shipments for certain years and that they are also entitled to collect interest on the refund. This matter is now pending before the U.S. Supreme Court.

In addition, at times the Company becomes a party to other claims, lawsuits, arbitration proceedings and administrative procedures in the ordinary course of business in the U.S., Australia and other countries where the Company does business. Based on current information, the Company believes that the ultimate resolution of such other pending or threatened proceedings is not reasonably likely to have a material adverse effect on its financial position, results of operations or liquidity.

New York Office of the Attorney General Subpoena

The New York Office of the Attorney General sent a letter to the Company dated September 14, 2007. The letter referred to the Company s plans to build new coal-fired electric generating units, and said that the increase in CO_2 emissions from the operation of these units, in combination with Peabody Energy s other coal-fired power plants, will subject Peabody Energy to increased financial, regulatory, and litigation risks. The Company currently has no electrical generating capacity in place. The letter included a subpoena issued under New York state law, which seeks information and documents relating to the Company s analysis of the risks associated with climate change and possible climate change legislation or regulations, and its disclosure of such risks to investors. The Company believes that it

has made full and proper disclosure of these potential risks.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(23) Summary Quarterly Financial Information (Unaudited)

A summary of the unaudited quarterly results of operations for the years ended December 31, 2007 and 2006, is presented below. The portions of the Eastern U.S. Mining operations business segment that were included in the spin-off of Patriot have been classified as discontinued operations and are excluded from the operating results for all periods presented. Peabody Energy common stock is listed on the New York Stock Exchange under the symbol BTU.

	Year Ended December 31, 2007			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Dollars in thousands except per share and stock price data)			
Revenues	$ 1,096,055	$ 1,065,835	$ 1,200,494	$ 1,212,328
Operating profit	147,384	174,891	112,896	133,553
Income from continuing operations	81,918	96,013	52,189	191,143
Net income	88,506	107,692	32,272	35,815
Basic earnings per share	$ 0.31	$ 0.37	$ 0.20	$ 0.72
Diluted earnings per share	$ 0.30	$ 0.36	$ 0.19	$ 0.71
Weighted average shares used in calculating basic earnings per share	263,031,869	263,479,042	263,871,330	265,861,546
Weighted average shares used in calculating diluted earnings per share	268,123,462	268,712,309	268,940,930	270,535,150
Stock price high and low prices	$ 44.60-$36.20	$ 55.76-$39.96	$ 50.99-$38.42	$ 62.55-$47.52
Dividends per share	$ 0.06	$ 0.06	$ 0.06	$ 0.06

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Second quarter operating profit included a $50.5 million gain resulting from an exchange of oil and gas rights for coal reserves (see Note 4 for information). Operating profit in the third and fourth quarters of 2007 included $17.8 million and $8.6 million, respectively, of gains from the sale of coal reserves and surface lands (see Note 4 for information). Operating profit for the third quarter of 2007 was negatively impacted by disruption in the coal-chain in Australia. Net income for the fourth quarter of 2007 included a tax benefit related to a reduction of $205.0 million in net operating loss valuation allowances, partially offset by ongoing tax expense and a $56.0 million impact on deferred taxes as a result of foreign exchange rates (see Note 12 for information).

	Year Ended December 31, 2006			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Dollars in thousands except per share and stock price data)			
Revenues	$ 1,022,900	$ 1,004,091	$ 980,396	$ 1,101,009
Operating profit	133,078	159,628	152,450	145,700
Income from continuing operations	109,257	142,005	140,516	160,796
Net income	130,222	153,434	142,008	175,033
Basic earnings per share	$ 0.42	$ 0.54	$ 0.53	$ 0.61
Diluted earnings per share	$ 0.41	$ 0.52	$ 0.52	$ 0.60
Weighted average shares used in calculating basic earnings per share	263,491,072	263,958,590	263,444,254	262,790,879
Weighted average shares used in calculating diluted earnings per share	269,358,728	269,756,666	268,822,681	268,137,610
Stock price high and low prices	$ 52.54-$41.24	$ 76.29-$46.81	$ 59.90-$32.94	$ 48.59-$34.05
Dividends per share	$ 0.06	$ 0.06	$ 0.06	$ 0.06

Second quarter operating profit included $39.2 million of gains resulting from exchanges of coal reserves (see Note 4 for information). Net income for the second quarter included the tax benefit related to a reduction in tax reserves due to the favorable finalization of former parent companies federal tax audits, partially offset by higher pretax earnings in 2006. Operating profit for the third quarter of 2006 benefited from lower performance-based compensation expense of $20.6 million. Net income for the fourth quarter of 2006 included a tax benefit related to the partial reduction in net operating loss valuation allowances (see Note 12 for information).

(24) Segment Information

The Company reports its operations primarily through the following reportable operating segments: Western U.S. Mining, Eastern U.S. Mining, Australian Mining and Trading and Brokerage. Western U.S. Mining operations reflect the aggregation of the Powder River Basin, Southwest and Colorado operating segments, and Eastern U.S. Mining operations reflects the Company s Midwest operating segments. The principal business of the Western U.S. Mining, Eastern U.S. Mining and Australian Mining segments is the mining, preparation and sale of steam coal, sold primarily to electric utilities, and metallurgical coal, sold to steel and coke producers. For the year ended December 31, 2007, 85% of the Company s sales were to U.S. electricity generators, 2% were to the U.S. industrial sector, and 13% were to customers outside the United States. Western U.S. Mining operations are characterized by predominantly surface mining extraction processes, lower sulfur content and Btu of coal and longer shipping distances

from the mine to the customer. Conversely, Eastern U.S. Mining operations are characterized by a mix of surface and underground mining extraction processes, higher sulfur content and Btu of coal and shorter shipping distances from the mine to the

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

customer. Geologically, Western operations mine bituminous and subbituminous coal deposits, and Eastern operations mine bituminous coal deposits. Australian Mining operations are characterized by both surface and underground extraction processes, mining low-sulfur, high Btu coal (metallurgical coal) as well as steam coal primarily sold to an international customer base with a small portion sold to Australian steel producers and power generators. The Trading and Brokerage segment s principal business is the marketing, brokerage and trading of coal. Corporate and Other includes selling and administrative expenses, net gains on property disposals, costs associated with past mining obligations, joint venture earnings related to the Company s 25.5% investment in a Venezuelan mine and revenues and expenses related to the Company s other commercial activities such as coalbed methane, generation development and resource management.

The Company s chief operating decision maker uses Adjusted EBITDA as the primary measure of segment profit and loss. Adjusted EBITDA is defined as income from continuing operations before deducting early debt extinguishment costs, net interest expense, income taxes, minority interests, asset retirement obligation expense and depreciation, depletion and amortization.

Operating segment results for the year ended December 31, 2007 were as follows:

	Western U.S. Mining	Eastern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
	(Dollars in thousands)					
Revenues	$ 2,061,265	$ 984,841	$ 1,161,093	$ 320,692	$ 46,821	$ 4,574,712
Adjusted EBITDA	597,333	196,595	159,473	110,169	(107,677)	955,893
Total assets	2,893,828	529,576	3,033,280	963,636	2,247,987	9,668,307
Additions to property, plant, equipment and mine development	175,423	35,763	168,258		90,990	470,434
Federal coal lease expenditures	178,193					178,193
Income (loss) from equity affiliates	10	(6,130)			20,581	14,461

Operating segment results for the year ended December 31, 2006 were as follows:

	Western U.S. Mining	Eastern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
	(Dollars in thousands)					

Revenues	$ 1,703,445	$ 905,743	$ 843,194	$ 652,029	$ 3,985	$ 4,108,396
Adjusted EBITDA	473,074	184,549	278,411	92,604	(127,682)	900,956
Total assets	2,628,070	348,790	2,784,922	240,329	3,511,945	9,514,056
Additions to property, plant, equipment and mine development	151,572	62,515	123,242	1,045	59,123	397,497
Federal coal lease expenditures	178,193					178,193
Income (loss) from equity affiliates	15	(4,968)			27,744	22,791

Operating segment results for the year ended December 31, 2005 were as follows:

	Western U.S. Mining	Eastern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
	(Dollars in thousands)					
Revenues	$ 1,611,587	$ 760,404	$ 598,085	$ 679,176	$ 16,924	$ 3,666,176
Adjusted EBITDA	459,039	168,793	202,582	43,058	(165,623)	707,849
Total assets	2,566,034	247,722	426,810	212,550	2,509,874	5,962,990
Additions to property, plant, equipment and mine development	197,742	48,157	85,335		119,114	450,348
Federal coal lease expenditures	118,364					118,364
Income (loss) from equity affiliates	14	(5,151)			20,364	15,227

A reconciliation of adjusted EBITDA to consolidated income from continuing operations follows:

	Year Ended December 31,		
	2007	2006	2005
	(Dollars in thousands)		
Total adjusted EBITDA	$ 955,893	$ 900,956	$ 707,849
Depreciation, depletion and amortization	(361,559)	(294,270)	(253,788)
Asset retirement obligation expense	(25,610)	(15,830)	(20,329)
Interest expense	(235,236)	(137,668)	(98,066)
Early debt extinguishment costs	253	(1,396)	
Interest income	7,094	11,309	9,088
Income tax (provision) benefit	78,112	90,084	(63,779)
Minority interests	2,316	(611)	(2,472)
Income from continuing operations	$ 421,263	$ 552,574	$ 278,503

(25) Supplemental Guarantor/Non-Guarantor Financial Information

In accordance with the indentures governing the 6.875% Senior Notes due March 2013, the 5.875% Senior Notes due March 2016, the 7.375% Senior Notes due November 2016 and the 7.875% Senior Notes due November 2026, certain wholly-owned U.S. subsidiaries of the Company have fully and unconditionally guaranteed these Senior Notes, on a joint and several basis. Separate financial statements and other disclosures concerning the Guarantor Subsidiaries are not presented because management believes that such information is not material to the Senior Note holders. The following historical financial statement information is provided for the Guarantor/Non-Guarantor Subsidiaries.

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2007				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
Total revenues	$	$ 3,429,228	$ 1,307,412	$ (161,928)	$ 4,574,712
Costs and expenses:					
Operating costs and expenses	(70,022)	2,621,908	1,184,860	(161,928)	3,574,818
Depreciation, depletion and amortization		242,380	119,179		361,559
Asset retirement obligation expense		18,823	6,787		25,610
Selling and administrative expenses	21,459	120,828	4,859		147,146
Other operating income:					
Net (gain) loss on disposal or exchange of assets		(88,831)	147		(88,684)
(Income) loss from equity affiliates	(549,741)	6,767	(21,228)	549,741	(14,461)
Interest expense	278,879	26,170	32,580	(102,393)	235,236
Early debt extinguishment costs	(253)				(253)
Interest income	(17,405)	(59,898)	(32,184)	102,393	(7,094)
Income before income taxes and minority interests	337,083	541,081	12,412	(549,741)	340,835
Income tax provision (benefit)	(84,180)	(65,660)	71,728		(78,112)
Minority interests		868	(3,184)		(2,316)
Income (loss) from continuing operations	421,263	605,873	(56,132)	(549,741)	421,263
Loss from discontinued operations, net of tax	(156,978)				(156,978)
Net income (loss)	$ 264,285	$ 605,873	$ (56,132)	$ (549,741)	$ 264,285

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2006				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
Total revenues	$	$ 2,968,631	$ 1,245,856	$ (106,091)	$ 4,108,396
Costs and expenses:					
Operating costs and expenses	(15,307)	2,334,793	942,337	(106,091)	3,155,732
Depreciation, depletion and amortization		229,247	65,023		294,270
Asset retirement obligation expense		15,293	537		15,830
Selling and administrative expenses	17,188	107,311	3,532		128,031
Other operating income:					
Net (gain) loss on disposal or exchange of assets		(53,585)	53		(53,532)
(Income) loss from equity affiliates	(661,245)	5,228	(28,019)	661,245	(22,791)
Interest expense	197,130	51,637	14,851	(125,950)	137,668
Early debt extinguishment costs	1,396				1,396
Interest income	(21,427)	(85,080)	(30,752)	125,950	(11,309)
Income before income taxes and minority interests	482,265	363,787	278,294	(661,245)	463,101
Income tax provision (benefit)	(70,309)	(99,611)	79,836		(90,084)
Minority interests		(152)	763		611
Income from continuing operations	552,574	463,550	197,695	(661,245)	552,574
Income from discontinued operations, net of tax	48,123				48,123
Net income	$ 600,697	$ 463,550	$ 197,695	$ (661,245)	$ 600,697

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2005				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
Total revenues	$	$ 2,721,451	$ 1,036,649	$ (91,924)	$ 3,666,176
Costs and expenses:					
Operating costs and expenses	(30,188)	2,191,860	815,572	(91,924)	2,885,320
Depreciation, depletion and amortization		220,279	33,509		253,788
Asset retirement obligation expense		19,658	671		20,329
Selling and administrative expenses	3,683	119,608	9,388		132,679
Other operating income:					
Net gain on disposal or exchange of assets		(44,185)	(260)		(44,445)
Income from equity affiliates	(342,697)	4,772	(19,999)	342,697	(15,227)
Interest expense	154,307	54,686	18,676	(129,603)	98,066
Interest income	(22,759)	(89,442)	(26,490)	129,603	(9,088)
Income before income taxes and minority interests	237,654	244,215	205,582	(342,697)	344,754
Income tax provision (benefit)	(40,849)	48,503	56,125		63,779
Minority interests		429	2,043		2,472
Income from continuing operations	278,503	195,283	147,414	(342,697)	278,503
Income from discontinued operations, net of tax	144,150				144,150
Net income	$ 422,653	$ 195,283	$ 147,414	$ (342,697)	$ 422,653

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED BALANCE SHEETS

	December 31, 2007				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
ASSETS					
Current assets					
Cash and cash equivalents	$ 6,909	$ 6,086	$ 32,284	$	$ 45,279
Accounts receivable, net	9,241	(399,178)	647,887		257,950
Inventories		138,285	130,577		268,862
Assets from coal trading activities		966,548			966,548
Deferred income taxes		98,633			98,633
Other current assets	102,146	55,223	58,559		215,928
Current assets of discontinued operations	74,093				74,093
Total current assets	192,389	865,597	869,307		1,927,293
Property, plant, equipment and mine development					
Land and coal interests		4,563,046	2,635,044		7,198,090
Buildings and improvements		577,044	123,465		700,509
Machinery and equipment		1,065,015	202,313		1,267,328
Less accumulated depreciation, depletion and amortization		(1,582,947)	(250,580)		(1,833,527)
Property, plant, equipment and mine development, net		4,622,158	2,710,242		7,332,400
Investments and other assets	7,734,604	(287,306)	4,096	(7,042,780)	408,614
Total assets	$ 7,926,993	$ 5,200,449	$ 3,583,645	$ (7,042,780)	$ 9,668,307
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities					
Current maturities of long-term debt	$ 122,681	$ (44)	$ 11,736	$	$ 134,373
Payables and notes payable to affiliates, net	1,903,040	(2,527,482)	624,442		
Liabilities from coal trading activities		918,596			918,596
Accounts payable and accrued expenses	23,998	670,604	259,059		953,661
	180,356				180,356

Current liabilities of discontinued operations					
Total current liabilities	2,230,075	(938,326)	895,237		2,186,986
Long-term debt, less current maturities	2,983,262	199	155,266		3,138,727
Deferred income taxes	65,734	(100,833)	350,703		315,604
Other noncurrent liabilities	95,015	1,278,314	100,053		1,473,382
Noncurrent liabilities of discontinued operations	33,236				33,236
Total liabilities	5,407,322	239,354	1,501,259		7,147,935
Minority interests		(4,145)	4,846		701
Stockholders equity	2,519,671	4,965,240	2,077,540	(7,042,780)	2,519,671
Total liabilities and stockholders equity	$ 7,926,993	$ 5,200,449	$ 3,583,645	$ (7,042,780)	$ 9,668,307

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED BALANCE SHEETS

	December 31, 2006				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
ASSETS					
Current assets					
Cash and cash equivalents	$ 272,226	$ 3,652	$ 50,633	$	$ 326,511
Accounts receivable, net		29,808	291,014		320,822
Inventories		114,176	88,733		202,909
Assets from coal trading activities		150,373			150,373
Deferred income taxes		77,562			77,562
Other current assets	54,007	35,107	20,745		109,859
Current assets of discontinued operations	108,522				108,522
Total current assets	434,755	410,678	451,125		1,296,558
Property, plant, equipment and mine development					
Land and coal interests		4,377,294	2,121,522		6,498,816
Buildings and improvements		498,780	123,279		622,059
Machinery and equipment		947,277	191,795		1,139,072
Less accumulated depreciation, depletion and amortization		(1,411,162)	(139,955)		(1,551,117)
Property, plant, equipment and mine development, net		4,412,189	2,296,641		6,708,830
Goodwill			240,667		240,667
Investments and other assets	7,060,642	(75,614)	66,910	(6,747,420)	304,518
Noncurrent assets of discontinued operations	963,483				963,483
Total assets	$ 8,458,880	$ 4,747,253	$ 3,055,343	$ (6,747,420)	$ 9,514,056
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities					
Current maturities of long-term debt	$ 27,350	$ 60,522	$ 7,885	$	$ 95,757
Payables and notes payable to affiliates, net	2,025,605	(2,135,941)	110,336		
		126,731			126,731

Liabilities from coal trading activities					
Accounts payable and accrued expenses	46,748	615,166	282,237		944,151
Current liabilities of discontinued operations	160,730				160,730
Total current liabilities	2,260,433	(1,333,522)	400,458		1,327,369
Long-term debt, less current maturities	3,017,107	13	164,155		3,181,275
Deferred income taxes	29,094	192,596	191,196		412,886
Other noncurrent liabilities	20,411	1,322,000	101,096		1,443,507
Noncurrent liabilities of discontinued operations	777,156				777,156
Total liabilities	6,104,201	181,087	856,905		7,142,193
Minority interests, including $16,153 of discontinued operations at December 31, 2006	16,153		17,184		33,337
Stockholders equity	2,338,526	4,566,166	2,181,254	(6,747,420)	2,338,526
Total liabilities and stockholders equity	$ 8,458,880	$ 4,947,253	$ 3,055,343	$ (6,747,420)	$ 9,514,056

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
	(Dollars in thousands)			
Cash Flows From Operating Activities				
Net cash provided by (used in) continuing operations	$ 1,410	$ 719,976	$ (274,205)	$ 447,181
Net cash used in discontinued operations	(130,816)			(130,816)
Net cash provided by (used in) operating activities	(129,406)	719,976	(274,205)	316,365
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development	(25,017)	(274,899)	(170,518)	(470,434)
Federal coal lease expenditures		(178,193)		(178,193)
Proceeds from disposal of assets, net of notes receivable		118,281	1,305	119,586
Additions to advance mining royalties		(8,093)	(30)	(8,123)
Investment in joint venture		(4,566)		(4,566)
Net cash used in continuing operations	(25,017)	(347,470)	(169,243)	(541,730)
Net cash used in discontinued operations	(33,602)			(33,602)
Net cash used in investing activities	(58,619)	(347,470)	(169,243)	(575,332)
Cash Flows From Financing Activities				
Change in revolving line of credit	97,700			97,700
Payments of long-term debt	(51,053)	(60,940)	(5,824)	(117,817)
Dividends paid	(63,658)			(63,658)
Payment of debt issuance costs		(774)		(774)
Excess tax benefit related to stock options exercised	96,743			96,743
Proceeds from stock options exercised	26,197			26,197
Proceeds from employee stock purchases	6,377			6,377
Transactions with affiliates, net	(122,565)	(308,358)	430,923	
Net cash provided by (used in) continuing operations	(10,259)	(370,072)	425,099	44,768
Net cash used in discontinued operations	(67,033)			(67,033)
Net cash provided by (used in) financing activities	(77,292)	(370,072)	425,099	(22,265)

Net increase (decrease) in cash and cash equivalents	(265,317)	2,434	(18,349)	(281,232)
Cash and cash equivalents at beginning of year	272,226	3,652	50,633	326,511
Cash and cash equivalents at end of year	$ 6,909	$ 6,086	$ 32,284	$ 45,279

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2006			
	Parent Company	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidated**
	(Dollars in thousands)			
Cash Flows From Operating Activities				
Net cash provided by (used in) continuing operations	$ (166,841)	$ 501,741	$ 256,512	591,412
Net cash used in discontinued operations	(8,150)			(8,150)
Net cash provided by (used in) operating activities	(174,991)	501,741	256,512	583,262
Cash Flows From Investing Activities				
Acquisition of Excel Coal, net of cash acquired			(1,507,775)	(1,507,775)
Additions to property, plant, equipment and mine development		(271,548)	(125,949)	(397,497)
Federal coal lease expenditures		(178,193)		(178,193)
Proceeds from disposal of assets, net of notes receivable		28,836	575	29,411
Additions to advance mining royalties		(4,956)		(4,956)
Investment in joint venture		(2,149)		(2,149)
Net cash used in continuing operations		(428,010)	(1,633,149)	(2,061,159)
Net cash used in discontinued operations	(82,659)			(82,659)
Net cash used in investing activities	(82,659)	(428,010)	(1,633,149)	(2,143,818)
Cash Flows From Financing Activities				
Proceeds from long-term debt	2,603,175		912	2,604,087
Payments of long-term debt	(876,972)	(10,957)	(158,044)	(1,045,973)
Common stock repurchase	(99,774)			(99,774)
Dividends paid	(63,456)			(63,456)
Payment of debt issuance costs	(40,611)			(40,611)
Excess tax benefit related to stock options exercised	33,173			33,173
Proceeds from stock options exercised	15,617			15,617
Proceeds from employee stock purchases	4,518			4,518
Transactions with affiliates, net	(1,516,234)	(61,622)	1,577,856	
Net cash provided by (used in) continuing operations	59,436	(72,579)	1,420,724	1,407,581
Net cash used in discontinued operations	(23,792)			(23,792)

Net cash provided by (used in) financing activities	35,644	(72,579)	1,420,724	1,383,789
Net increase (decrease) in cash and cash equivalents	(222,006)	1,152	44,087	(176,767)
Cash and cash equivalents at beginning of year	494,232	2,500	6,546	503,278
Cash and cash equivalents at end of year	$ 272,226	$ 3,652	$ 50,633	$ 326,511

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2005			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
	(Dollars in thousands)			
Cash Flows From Operating Activities				
Net cash provided by (used in) continuing operations	$ (126,861)	$ 602,798	$ 207,867	683,804
Net cash provided by discontinued operations	41,457			41,457
Net cash provided by (used in) operating activities	(85,404)	602,798	207,867	725,261
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development		(363,084)	(87,264)	(450,348)
Federal coal lease expenditures		(118,364)		(118,364)
Proceeds from disposal of assets, net of notes receivable		60,607	2,124	62,731
Additions to advance mining royalties		(8,472)		(8,472)
Investment in joint venture		(2,000)		(2,000)
Net cash used in continuing operations		(431,313)	(85,140)	(516,453)
Net cash used in discontinued operations	(67,749)			(67,749)
Net cash used in investing activities	(67,749)	(431,313)	(85,140)	(584,202)
Cash Flows From Financing Activities				
Proceeds from long-term debt		11,734		11,734
Payments of long-term debt	(6,250)	(12,959)	(989)	(20,198)
Dividends paid	(44,535)			(44,535)
Proceeds from stock options exercised	22,573			22,573
Issuance of notes payable		(11,459)		(11,459)
Proceeds from employee stock purchases	3,009			3,009
Transactions with affiliates, net	288,063	(159,797)	(128,266)	
Net cash provided by (used in) continuing operations	262,860	(172,481)	(129,255)	(38,876)
Net cash provided by discontinued operations	11,459			11,459
Net cash provided by (used in) financing activities	274,319	(172,481)	(129,255)	(27,417)
Net increase (decrease) in cash and cash equivalents	121,166	(996)	(6,528)	113,642

Cash and cash equivalents at beginning of year	373,066	3,496	13,074	389,636
Cash and cash equivalents at end of year	$ 494,232	$ 2,500	$ 6,546	$ 503,278

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited the consolidated financial statements of Peabody Energy Corporation as of December 31, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, and have issued our report thereon dated February 27, 2008. Our audits also included the financial statement schedule listed in Item 15(a). This schedule is the responsibility of the Company s management. Our responsibility is to express an opinion based on our audits. In our opinion, the financial statement schedule referred to above, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 27, 2008

PEABODY ENERGY CORPORATION

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions[1]	Other	Balance at End of Period
			(Dollars in thousands)		
Year ended December 31, 2007					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 11,958	$	$	$ 1,643[2]	$ 13,601
Reserve for materials and supplies	3,241	458	(652)	1,252[2]	4,299
Allowance for doubtful accounts	10,893	1,124	(129)		11,888
Year ended December 31, 2006					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 12,414	$	$	$ (456)[2]	$ 11,958
Reserve for materials and supplies	3,426	229		(414)[2]	3,241
Allowance for doubtful accounts	10,761	446		(314)[2]/[4]	10,893
Year ended December 31, 2005					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 11,250	$ 867	$	$ 297[2]	$ 12,414
Reserve for materials and supplies	2,602	836	(1,531)	1,519[2]	3,426
Allowance for doubtful accounts	1,361	20,305[3]	(5,860)	(5,045)[4]	10,761

[1] Reserves utilized, unless otherwise indicated.

[2] Balances transferred (to) from other accounts or reserves recorded as part of a property transaction or acquisition.

[3] Includes $19.5 million for the establishment of a reserve for the collectibility of certain receivables billed prior to 2005.

[4] Reflects subsequent recovery of amounts previously reserved.

EXHIBIT INDEX

The exhibits below are numbered in accordance with the Exhibit Table of Item 601 of Regulation S-K.

Exhibit No.	Description of Exhibit
2.1	Merger Implementation Agreement, dated as of July 6, 2006, between the Registrant and Excel Coal Limited (Incorporated by reference to Exhibit 2.1 of the Registrant s Current Report on Form 8-K, filed on July 7, 2006).
2.2	Deed of Variation Merger Implementation Agreement, dated as of September 18, 2006, between the Registrant and Excel Coal Limited (Incorporated by reference to Exhibit 2.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).
3.1	Third Amended and Restated Certificate of Incorporation of the Registrant, as amended (Incorporated by reference to Exhibit 3.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
3.2	Amended and Restated By-Laws of the Registrant (Incorporated by reference to Exhibit 3.2 of the Registrant s Current Report on Form 8-K filed on August 2, 2007).
4.1	Rights Agreement, dated as of July 24, 2002, between the Registrant and EquiServe Trust Company, N.A., as Rights Agent (which includes the form of Certificate of Designations of Series A Junior Preferred Stock of the Registrant as Exhibit A, the form of Right Certificate as Exhibit B and the Summary of Rights to Purchase Preferred Shares as Exhibit C) (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Registration Statement on Form 8-A, filed on July 24, 2002).
4.2	Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant, filed with the Secretary of State of the State of Delaware on July 24, 2002 (Incorporated herein by reference to Exhibit 3.1 to the Registrant s Registration Statement on Form 8-A, filed on July 24, 2002).
4.3	Certificate of Adjustment delivered by the Registrant to Equiserve Trust Company, NA., as Rights Agent, on March 29, 2005 (Incorporated by reference to Exhibit 4.2 to Amendment No. 1 to the Registrant s Registration Statement on Form 8-A, filed on March 29, 2005).
4.4	Certificate of Adjustment delivered by the Registrant to American Stock Transfer & Trust Company, as Rights Agent, on February 22, 2006 (Incorporated by reference to Exhibit 4.2 to Amendment No. 1 to the Registrant s Registration Statement on Form 8-A, filed on February 22, 2006).
4.5	Specimen of stock certificate representing the Registrant s common stock, $.01 par value (Incorporated by reference to Exhibit 4.13 of the Registrant s Form S-1 Registration Statement No. 333-55412).
4.6	67/8% Senior Notes Due 2013 Indenture, dated as of March 21, 2003, between the Registrant and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.27 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003, filed on May 13, 2003).
4.7	67/8% Senior Notes Due 2013 First Supplemental Indenture, dated as of May 7, 2003, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant s Form S-4 Registration Statement No. 333-106208).
4.8	67/8% Senior Notes Due 2013 Second Supplemental Indenture, dated as of September 30, 2003, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.198 of the Registrant s Form S-3 Registration Statement No. 333-109906, filed on October 22, 2003).
4.9	67/8% Senior Notes Due 2013 Third Supplemental Indenture, dated as of February 24, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.211 of the Registrant s Form S-3/A Registration

Statement No. 333-109906, filed on March 4, 2004).

Exhibit No.	Description of Exhibit
4.10	67/8% Senior Notes Due 2013 Fourth Supplemental Indenture, dated as of April 22, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 10.57 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).
4.11	67/8% Senior Notes Due 2013 Fifth Supplemental Indenture, dated as of October 18, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.9 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 16, 2005).
4.12	67/8% Senior Notes Due 2013 Sixth Supplemental Indenture, dated as of January 20, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed on May 6, 2005).
4.13	67/8% Senior Notes Due 2013 Seventh Supplemental Indenture, dated as of September 30, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, filed on November 8, 2005).
4.14	67/8% Senior Notes Due 2013 Eighth Supplemental Indenture, dated as of January 20, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.14 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2005, filed on March 6, 2006).
4.15	67/8% Senior Notes Due 2013 Ninth Supplemental Indenture, dated as of June 13, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
4.16	67/8% Senior Notes Due 2013 Tenth Supplemental Indenture, dated as of June 30, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
4.17	67/8% Senior Notes Due 2013 Eleventh Supplemental Indenture, dated as of September 29, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).
4.18	67/8% Senior Notes Due 2013 Twelfth Supplemental Indenture, dated as of November 10, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.18 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006, filed on February 28, 2007).
4.19	67/8% Senior Notes Due 2013 Thirteenth Supplemental Indenture, dated as of January 31, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.19 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006, filed on February 28, 2007)
4.20	67/8% Senior Notes Due 2013 Fourteenth Supplemental Indenture, dated as of June 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).

4.21	67/8% Senior Notes Due 2013 Fifteenth Supplemental Indenture, dated as of November 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee.
4.22	57/8% Senior Notes Due 2016 Indenture, dated as of March 19, 2004, between the Registrant and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.12 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, filed on May 10, 2004).

Exhibit No.	Description of Exhibit
4.23	57/8% Senior Notes Due 2016 First Supplemental Indenture, dated as of March 23, 2004, between the Registrant and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K dated March 23, 2004).
4.24	57/8% Senior Notes Due 2016 Second Supplemental Indenture, dated as of April 22, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 10.58 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).
4.25	57/8% Senior Notes Due 2016 Third Supplemental Indenture, dated as of October 18, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.13 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 16, 2005).
4.26	57/8% Senior Notes Due 2016 Fourth Supplemental Indenture, dated as of January 20, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed on May 6, 2005).
4.27	57/8% Senior Notes Due 2016 Fifth Supplemental Indenture, dated as of September 30, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, filed on November 8, 2005).
4.28	57/8% Senior Notes Due 2016 Sixth Supplemental Indenture, dated as of January 20, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.21 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2005, filed on March 6, 2006).
4.29	57/8% Senior Notes Due 2016 Seventh Supplemental Indenture, dated as of June 13, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
4.30	57/8% Senior Notes Due 2016 Eighth Supplemental Indenture, dated as of June 30, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
4.31	57/8% Senior Notes Due 2016 Ninth Supplemental Indenture, dated as of September 29, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).
4.32	57/8% Senior Notes Due 2016 Twelfth Supplemental Indenture, dated as of November 10, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.30 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006, filed on February 28, 2007).
4.33	57/8% Senior Notes Due 2016 Fifteenth Supplemental Indenture, dated as of January 31, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.31 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006, filed on February 28, 2007).
4.34	57/8% Senior Notes Due 2016 Eighteenth Supplemental Indenture, dated as of June 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as

trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).

4.35 57/8% Senior Notes Due 2016 Twenty-First Supplemental Indenture, dated as of November 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee.

4.36 73/8% Senior Notes due 2016 Tenth Supplemental Indenture, dated as of October 12, 2006 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K dated October 13, 2006).

Exhibit No.	Description of Exhibit
4.37	73/8% Senior Notes due 2016 Thirteenth Supplemental Indenture, dated as of November 10, 2006 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.33 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006, filed on February 28, 2007).
4.38	73/8% Senior Notes due 2016 Sixteenth Supplemental Indenture, dated as of January 31, 2007 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.34 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006, filed on February 28, 2007).
4.39	73/8% Senior Notes due 2016 Nineteenth Supplemental Indenture, dated as of June 14, 2007 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
4.40	73/8% Senior Notes due 2016 Twenty-Second Supplemental Indenture, dated as of November 14, 2007 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee.
4.41	77/8% Senior Notes due 2026 Eleventh Supplemental Indenture, dated as of October 12, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Current Report on Form 8-K dated October 13, 2006).
4.42	77/8% Senior Notes due 2026 Fourteenth Supplemental Indenture, dated as of November 10, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.36 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006, filed on February 28, 2007).
4.43	77/8% Senior Notes due 2026 Seventeenth Supplemental Indenture, dated as of January 31, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.37 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006, filed on February 28, 2007).
4.44	77/8% Senior Notes due 2026 Twentieth Supplemental Indenture, dated as of June 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
4.45	77/8% Senior Notes due 2026 Twenty-Third Supplemental Indenture, dated as of November 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee.
4.46	Subordinated Indenture, dated as of December 20, 2006, between the Registrant and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K, filed December 20, 2006).
4.47	4.75% Convertible Junior Subordinated Debentures Due 2066 First Supplemental Indenture, dated as December 20, 2006, among the Registrant and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Current Report on Form 8-K, filed December 20, 2006).
4.48	Capital Replacement Covenant dated December 19, 2006 (Incorporated by reference to Exhibit 99.1 of the Registrant s Current Report on Form 8-K, filed December 20, 2006).
4.49	Notice of Adjustment of Conversion Rate of 4.75% Convertible Junior Subordinated Debentures Due 2066, dated November 26, 2007.

10.1	Third Amended and Restated Credit Agreement, dated as of September 15, 2006, among the Registrant, Bank of America, N.A., as administrative agent, Citibank, N.A., as syndication agent, and the lenders named therein (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed September 18, 2006).
10.2	Amendment No. 1 to Third Amended and Restated Credit Agreement, dated as of September 27, 2006, among the Registrant, the Lenders named therein, and Bank of America, N.A., as Administrative Agent (Incorporated by reference to Exhibit 10.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).

Exhibit No.	Description of Exhibit
10.3	Amended and Restated Guarantee, dated as of September 15, 2006, among the Registrant and the Guarantors (as defined therein) in favor of Bank of America, N.A., as administrative agent under the Third Amended and Restated Credit Agreement dated as of September 15, 2006 (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed September 18, 2006).
10.4	Federal Coal Lease WYW0321779: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.3 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.5	Federal Coal Lease WYW119554: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.4 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.6	Federal Coal Lease WYW5036: Rawhide Mine (Incorporated by reference to Exhibit 10.5 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.7	Federal Coal Lease WYW3397: Caballo Mine (Incorporated by reference to Exhibit 10.6 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.8	Federal Coal Lease WYW83394: Caballo Mine (Incorporated by reference to Exhibit 10.7 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.9	Federal Coal Lease WYW136142 (Incorporated by reference to Exhibit 10.8 of Amendment No. 1 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.10	Royalty Prepayment Agreement by and among Peabody Natural Resources Company, Gallo Finance Company and Chaco Energy Company, dated September 30, 1998 (Incorporated by reference to Exhibit 10.9 of the Registrant s Quarterly Report on Form 10-Q for the second quarter ended September 30, 1998, filed on November 13, 1998).
10.11	Federal Coal Lease WYW154001: North Antelope Rochelle South (Incorporated by reference to Exhibit 10.68 of the Registrant s Quarterly Report on Form 10-Q for the third quarter ended September 30, 2004, filed on December 10, 2004).
10.12	Federal Coal Lease WYW150210: North Antelope Rochelle Mine (Incorporated by reference to Exhibit 10.8 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed on May 6, 2005).
10.13	Federal Coal Lease WYW151134 effective May 1, 2005: West Roundup (Incorporated by reference to Exhibit 10.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, filed on August 8, 2005).
10.14	Separation Agreement, Plan of Reorganization and Distribution, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed October 25, 2007).
10.15	Tax Separation Agreement, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K filed October 25, 2007).
10.16	Coal Act Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K filed October 25, 2007).
10.17	NBCWA Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC, Peabody Coal Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K filed October 25, 2007).
10.18	Salaried Employee Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC, Peabody Coal Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.5 of the Registrant s Current Report on Form 8-K filed October 25, 2007).

10.19	Coal Supply Agreement, dated October 22, 2007, between Patriot Coal Sales LLC and COALSALES II, LLC (Incorporated by reference to Exhibit 10.6 of the Registrant s Current Report on Form 8-K filed October 25, 2007).
10.20*	1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 4.9 of the Registrant s Form S-8 Registration Statement No. 333-105456, filed on May 21, 2003).

Exhibit No.	Description of Exhibit
10.21*	Amendment to the 1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K filed October 17, 2007).
10.22*	Amendment No. 2 to the 1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K filed December 11, 2007).
10.23*	Form of Non-Qualified Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.15 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.24*	Form of Amendment to Non-Qualified Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.16 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.25*	Form of Amendment, dated as of June 15, 2004, to Non-Qualified Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.65 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).
10.26*	Form of Incentive Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.17 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.27*	Long-Term Equity Incentive Plan of the Registrant (Incorporated by reference to Exhibit 99.2 of the Registrant s Form S-8 Registration Statement No. 333-61406, filed on May 22, 2001).
10.28*	Amendment to the Registrant s 2001 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K filed October 17, 2007).
10.29*	The Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Annex A to the Registrant s Proxy Statement for the 2004 Annual Meeting of Stockholders, filed on April 2, 2004).
10.30*	Amendment No. 1 to the Registrant s 2004 Long Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.67 of the Registrant s Quarterly Report on Form 10-Q for the third quarter ended September 30, 2004, filed on December 10, 2004).
10.31*	Amendment No. 2 to the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed October 17, 2007).
10.32*	Amendment No. 3 to the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K filed October 17, 2007).
10.33*	Amendment No. 4 to the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed December 11, 2007).
10.34*	Form of Non-Qualified Stock Option Agreement under the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K, filed on January 7, 2005).
10.35*	Form of Performance Units Agreement under the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, dated January 3, 2005).
10.36*	Form of Performance Units Agreement under the Registrant s 2004 Long-Term Equity Incentive Plan.
10.37*	Equity Incentive Plan for Non-Employee Directors of the Registrant (Incorporated by reference to Exhibit 99.3 of the Registrant s Form S-8 Registration Statement No. 333-61406, filed on May 22, 2001).

Exhibit No.	Description of Exhibit
10.38*	Form of Non-Qualified Stock Option Agreement for Outside Directors under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K, filed on December 14, 2005).
10.39*	Form of Non-Qualified Stock Option Agreement under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.18 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.40*	Form of Performance Unit Award Agreement under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.19 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.41*	Form of Non-Qualified Stock Option Agreement under the Registrant s Equity Incentive Plan for Non-Employee Directors (Incorporated by reference to Exhibit 10.20 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.42*	Form of Restricted Stock Agreement under the Registrant s Equity Incentive Plan for Non-Employee Directors (Incorporated by reference to Exhibit 10.21 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.43*	Form of Restricted Stock Award Agreement for Outside Directors under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K, filed on December 14, 2005).
10.44*	Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 99.1 of the Registrant s Form S-8 Registration Statement No. 333-61406, filed on May 22, 2001).
10.45*	First Amendment to Registrant s Employee Stock Purchase Plan, dated as of February 7, 2002 (Incorporated by reference to Exhibit 10.23 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.46*	Second Amendment to Registrant s Employee Stock Purchase Plan (Incorporated by reference to Exhibit 10.5 of the Registrant s Current Report on Form 8-K filed October 17, 2007).
10.47*	Third Amendment to Registrant s Employee Stock Purchase Plan.
10.48*	Letter Agreement, dated as of March 1, 2005, by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed March 4, 2005).
10.49*	Amended and Restated Employment Agreement, dated as of January 1, 2006, by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K, filed March 4, 2005).
10.50*	Employment Agreement between Richard A. Navarre and the Registrant dated May 19, 1998 (Incorporated by reference to Exhibit 10.13 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.51*	First Amendment to the Employment Agreement between Richard A. Navarre and the Registrant dated as of May 10, 2001 (Incorporated by reference to Exhibit 10.23 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.52*	Second Amendment to the Employment Agreement between Richard A. Navarre and the Registrant dated as of June 15, 2004 (Incorporated by reference to Exhibit 10.61 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).
10.53*	Employment Agreement between Roger B. Walcott, Jr. and the Registrant dated May 19, 1998 (Incorporated by reference to Exhibit 10.14 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.54*	

	First Amendment to the Employment Agreement between Roger B. Walcott, Jr. and the Registrant dated as of May 10, 2001 (Incorporated by reference to Exhibit 10.24 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.55*	Second Amendment to the Employment Agreement between Roger B. Walcott and the Registrant dated as of June 15, 2004 (Incorporated by reference to Exhibit 10.62 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).

Exhibit No.	Description of Exhibit
10.56*	Letter Agreement, dated as of December 22, 2006, by and between the Registrant and Eric Ford (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10.57*	Employment Agreement, dated as of December 22, 2006, by and between the Company and Eric Ford (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10.57A*	Form of Restricted Stock Agreement Exhibit A (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10.57B*	Form of Restricted Stock Agreement Exhibit B (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10.58*	Employment Agreement between Sharon D. Fiehler and the Registrant dated May 19, 1998.
10.59*	First Amendment to the Employment Agreement between Sharon D. Fiehler and the Registrant dated as of May 10, 2001.
10.60*	Second Amendment to the Employment Agreement between Sharon D. Fiehler and the Registrant dated as of June 15, 2004.
10.61*	Management Annual Incentive Compensation Plan.
10.62*	The Registrant s Deferred Compensation Plan (Incorporated by reference to Exhibit 10.30 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, filed on October 30, 2001).
10.63*	First Amendment to the Registrant s Deferred Compensation Plan (Incorporated by reference to Exhibit 10.49 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 16, 2005).
10.64*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and William E. James (Incorporated by reference to Exhibit 10.34 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.65*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Henry E. Lentz (Incorporated by reference to Exhibit 10.35 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.66*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and William C. Rusnack (Incorporated by reference to Exhibit 10.36 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.67*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Dr. James R. Schlesinger (Incorporated by reference to Exhibit 10.37 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.68*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Dr. Blanche M. Touhill (Incorporated by reference to Exhibit 10.38 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.69*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Alan H. Washkowitz (Incorporated by reference to Exhibit 10.39 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.70*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Richard A. Navarre (Incorporated by reference to Exhibit 10.40 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.71*	Indemnification Agreement, dated as of January 16, 2003, by and between Registrant and Robert B. Karn III (Incorporated by reference to Exhibit 10.41 of the Registrant s Annual Report on Form 10-K

for the year ended December 31, 2002, filed on March 7, 2003).

10.72* Indemnification Agreement, dated as of January 16, 2003, by and between Registrant and Sandra A. Van Trease (Incorporated by reference to Exhibit 10.42 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).

10.73* Indemnification Agreement, dated as of March 22, 2004, by and between Registrant and Henry Givens, Jr. (Incorporated by reference to Exhibit 10.52 of the Registrant s Quarterly Report on Form 10-Q for the quarter Ended March 31, 2004, filed on May 10, 2004).

Exhibit No.	Description of Exhibit
10.74*	Indemnification Agreement, dated as of March 22, 2004, by and between Registrant and William A. Coley (Incorporated by reference to Exhibit 10.53 of the Registrant s Quarterly Report on Form 10-Q for the quarter Ended March 31, 2004, filed on May 10, 2004).
10.75*	Indemnification Agreement, dated as of April 8, 2005, by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed April 14, 2005).
10.76*	Indemnification Agreement, dated July 21, 2005, by and between the Registrant and John F. Turner (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed on August 5, 2005).
10.77*	Peabody Investments Corp. Supplemental Employee Retirement Account (Incorporated by reference to Exhibit 10.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
10.78	Amended and Restated Receivables Purchase Agreement, dated as of September 30, 2005, by and among Seller, the Registrant, the Sub-Servicers named therein, Market Street Funding Corporation, as Issuer, and PNC Bank, National Association, as Administrator (Incorporated by reference to Exhibit 10.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, filed on August 8, 2005).
10.79	Second Amendment to Amended and Restated Receivables Purchase Agreement, dated as of May 15, 2007, by and among the Seller, the Registrant, the Sub-Servicers named therein, Market Street Funding LLC, as Issuer, and PNC Bank, National Association, as Administrator (Incorporated by reference to Exhibit 10.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
21	List of Subsidiaries.
23	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
31.1	Certification of periodic financial report by the Registrant s Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of periodic financial report by the Registrant s Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant s Chief Executive Officer.
32.2	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant s Chief Financial Officer.

* These exhibits constitute all management contracts, compensatory plans and arrangements required to be filed as an exhibit to this form pursuant to Item 15(a)(3) and 15(b) of this report.

Filed herewith.