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.

		Proven and Probable Reserves as of December 31, 2007[1]		
Operating Regions	**Locations**	**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