PEABODY ENERGY CORP
Form 10-K
February 28, 2007

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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, 2006

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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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 30, 2006: Common Stock, par value $0.01 per share, $14.6 billion.

Number of shares outstanding of each of the Registrant s classes of Common Stock, as of February 16, 2007: Common Stock, par value $0.01 per share, 264,685,954 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 Annual Meeting of Stockholders to be held on May 1, 2007 (the Company s 2007 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.

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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, will or other similar w 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. 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;
- weather;
- legislation, regulations and court decisions;
- new environmental requirements affecting the use of coal including mercury and carbon dioxide related limitations;
- changes in postretirement benefit and pension obligations;
- changes to contribution requirements to multi-employer benefit funds;
- 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;
- risks associated with customer contracts, including credit and performance risk;
- the effects of acquisitions or divestitures, including integration of new acquisitions;

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 current information systems;

growth of domestic and international coal and power markets;

coal s market share of electricity generation;

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prices of fuels which compete with or impact coal usage, such as oil or natural gas;

future worldwide economic conditions;

successful implementation of business strategies;

variation in revenues related to synthetic fuel production due to expiration of related tax credits at the end of 2007;

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;

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. We do not undertake any 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 Corporation or its applicable subsidiary or subsidiaries.

PART I

Item 1. *Business.*

Overview

We are the largest private-sector coal company in the world. During the year ended December 31, 2006, we sold 247.6 million tons of coal. During this period, we sold coal to over 400 electricity generating and industrial plants in 20 countries. Our coal products fuel approximately 10% of all U.S. electricity generation and 2% of worldwide electricity generation. At December 31, 2006, we had 10.2 billion tons of proven and probable coal reserves.

We own majority interests in 40 coal operations located throughout all major U.S. coal producing regions and in Australia. Additionally, we own a minority interest in one Venezuelan mine through a joint venture arrangement. We shipped 75% of our U.S. mining operations coal sales from the western United States during the year ended December 31, 2006 and the remaining 25% 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 127.0 million tons in 2001, the year of our initial public offering, to 160.5 million tons during 2006, representing a compounded annual growth rate of 5%. 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, Indiana, Kentucky and West Virginia. We own six mines, including one late development-stage mine in Queensland, Australia, and five mines, including one late development-stage mine and one development-stage mine in New South Wales, Australia. Our Australian production includes both low-sulfur thermal coal and high Btu metallurgical coal. We generated 86% of our production for the year ended December 31, 2006 from non-union mines.

For the year ended December 31, 2006, 87% of our sales (by volume) were to U.S. electricity generators, 9% were to customers outside the United States and 4% were to the U.S. industrial sector. Approximately 90% of our coal sales during the year ended December 31, 2006 were under long-term (one year or greater) contracts. Our sales backlog, including backlog subject to price reopener and/or extension provisions, was over one billion tons as of December 31, 2006. The average volume-weighted remaining term of our long-term contracts was approximately 5 years, with remaining terms ranging from one to 19 years. We are targeting 2007 production of 240 to 260 million tons and total sales volume of 265 to 285 tons, including 15 to 18 million tons of metallurgical coal. As of December 31, 2006, our unpriced 2007 volumes for planned produced tonnage were 5 to 15 million U.S. tons and 14 million Australia tons. Our total unpriced planned production for 2008 is approximately 70 to 80 million tons in the United States and 20 to 22 million tons in Australia.

In addition to our mining operations, we market, broker and trade coal. Our total tons traded were 79.1 million for the year ended December 31, 2006. In response to growing international markets, we established an international trading group in 2006 and added another 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 in this market. 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, coalbed methane production, and Btu Conversion technologies, which are designed to convert coal to natural gas and transportation fuels.

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

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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, and completing the acquisitions of the West Virginia coal properties of ARMCO Steel and Eastern Associated Coal Corp., which included seven operating mines and substantial low-sulfur coal reserves in West Virginia.

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 71%-owned 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 acquired Excel Coal Limited (Excel), an independent coal company in Australia. The Excel acquisition included three operating mines, two late development-stage mines and a development-stage mine, along with estimated proven and probable coal reserves in excess of 500 million tons.

Peabody has grown significantly in recent years through both organic growth and acquisitions while transforming itself 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. Peabody remains focused on areas identified as necessary for achieving future growth: 1) executing the basics of best-in-class safety, operations and marketing; 2) capitalizing on organic growth opportunities; 3) expanding in high-growth global markets; and 4) participating in new generation and Btu Conversion technologies that convert coal into natural gas, liquids and hydrogen.

Mining Operations

We conduct 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

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Appalachia and Midwest operations. The principal business of the Western U.S. Mining segment is the mining, preparation and sale of steam coal, sold primarily to electric utilities. The principal business of the Eastern U.S. Mining segment is the mining, preparation and sales of steam coal, sold primarily to electric utilities, as well as the mining of some metallurgical coal, sold to steel and coke producers. Internationally, we operate 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 25 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, 2006. Included in the descriptions of our mining operations are discussions of the subsidiaries which manage the respective mining operation. 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 respective mining operations and related assets.

U.S. Mining Operations

Powder River Basin Operations

We control approximately 3.5 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. Our subsidiaries, Powder River Coal, LLC and Caballo Coal Company, manage three low-sulfur, non-union surface mining complexes in Wyoming that sold 138.4 million tons of coal during the year ended December 31, 2006, or approximately 56% 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 8,900 Btu s per pound.

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North Antelope Rochelle Mine

The North Antelope Rochelle Mine is located 65 miles south of Gillette, Wyoming. This mine is one of the largest in North America, selling 88.5 million tons of compliance coal (defined as having sulfur dioxide content of 1.2 pounds or less per million Btu) during 2006. The North Antelope Rochelle facility is capable of loading its production in up to 20 unit trains per day (a unit train generally consists of 100 to 150 cars, each of which holds 100 to 120 tons of coal). The North Antelope Rochelle Mine produces premium quality coal with a sulfur content averaging 0.2% and a heat value ranging from 8,500 to 8,900 Btu per pound. The North Antelope Rochelle Mine produces the lowest sulfur coal in the United States, using two draglines along with six truck-and-shovel fleets. A third dragline is under construction and is scheduled for completion in mid-2007.

Caballo Mine

The Caballo Mine is located 20 miles south of Gillette, Wyoming. During 2006, it sold 32.8 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 is capable of loading its production in up to nine unit trains per day. 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 ten miles north of Gillette, Wyoming and uses truck-and-shovel mining methods. During 2006, 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 is capable of loading its production in up to six unit trains per day. The Rawhide Mine produces compliance coal with a sulfur content averaging 0.38% and a heat value averaging 8,300 Btu per pound.

Southwest Operations

We own three mines in our Southwest operations, and we are currently operating two of these mines, one in Arizona and one in New Mexico. The third mine in Arizona suspended operations as of December 31, 2005. The Arizona mines are managed by our Peabody Western Coal Company subsidiary. In New Mexico, we own and manage, through our Peabody Natural Resources Company subsidiary, the Lee Ranch Mine, which mines and produces subbituminous medium sulfur coal. Together, these two mines sold 13.2 million tons of coal during 2006. 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 8.0 million tons of coal during 2006 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).

Lee Ranch Mine

The Lee Ranch Mine, located near Grants, New Mexico, sold approximately 5.2 million tons of medium sulfur coal during 2006. 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

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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.

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. Our Twentymile underground mine is managed by our Twentymile Coal Company subsidiary. Our Seneca surface mine is managed by our Seneca Coal Company subsidiary and ceased mining operations at the end of 2005.

Twentymile Mine

The Twentymile Mine is located in Routt County, Colorado, and sold 8.8 million tons of compliance, low-sulfur, steam coal of above average heat content for the region to customers throughout the United States during 2006. This mine uses both longwall and continuous mining equipment. Our Twentymile Mine is non-union and has been one of the largest and most productive underground mines in the United States. Approximately 78% of all coal shipped is loaded on the Union Pacific railroad; the remainder is hauled by truck. This mine also provides coal to the nearby Hayden Generating Station, operated by the Public Service of Colorado, under a coal supply agreement that extends until 2011.

Appalachia/ Highland Operations

The Appalachia/ Highland Operations consist of five wholly-owned business units and related facilities, a joint venture in West Virginia and one business unit in western Kentucky. Our subsidiary, Pine Ridge Coal Company, LLC, manages the Big Mountain Business Unit, and our subsidiary, Rivers Edge Mining, Inc. manages our Rivers Edge Mine in our Wells Business Unit. Our Eastern Associated Coal, LLC subsidiary manages the remaining wholly-owned West Virginia facilities. In addition, Highland Mining manages the Highland No. 9 Mine in western Kentucky. During 2006, these operations sold approximately 18.8 million tons of compliance, medium-sulfur and high-sulfur steam and metallurgical coal to customers in the United States and abroad. Metallurgical coal from these operations accounted for 5.6 million tons of total sales for the year. In addition to our wholly-owned facilities, we own a 73.9% interest in KE Ventures LLC, a joint venture which owns and manages underground mining operations. We control approximately 0.6 billion tons of proven and probable coal reserves in our Appalachia operations. Our Appalachia Operations also own a 30% interest in a partnership that leases a coal export terminal from the Peninsula Port Authority of Virginia and utilizes the terminal for exports.

Big Mountain Business Unit and Contract Mines

The Big Mountain Business Unit is based near Prenter, West Virginia. This business unit s primary source of coal (approximately 55% of total shipments) is the Big Mountain No. 16 operation with the remainder from contract mine production from coal reserves we control. All production is processed at the business unit s preparation facility. During 2006, the Big Mountain Business Unit sold approximately 2.0 million tons of steam coal. Big Mountain No. 16 is an underground mine using continuous mining equipment. Processed coal is loaded on the CSX railroad. Our hourly employees at the Big Mountain Business Unit are represented by the UMWA.

Harris Business Unit

The Harris Business Unit is based near Bald Knob, West Virginia. The business unit s primary source of coal is the Harris No. 1 Mine. The business unit also has a small amount of contract mine production from a mine also located near Bald Knob, West Virginia. The Harris Business Unit sold approximately 1.5 million tons of primarily metallurgical product during 2006. This mine uses both longwall and continuous mining equipment. In 2006, the Harris Business Unit transitioned to the James Creek reserves, allowing it to access additional metallurgical coal. Hourly employees at the Harris Business Unit are represented by the UMWA.

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Rocklick Business Unit and Contract Mines

The Rocklick preparation plant, located near Wharton, West Virginia, processes metallurgical coal produced by the Harris Business Unit and steam coal produced from contract mining operations. This preparation plant shipped approximately 2.2 million tons of contract mine steam coal during 2006. Processed coal is loaded at the plant site on the CSX railroad or transferred via conveyor to our Kopperston loadout facility and loaded on the Norfolk Southern railroad. Hourly employees at the Rocklick preparation plant are represented by the UMWA.

Wells Business Unit

The Wells Business Unit, located near Wharton, West Virginia, sold approximately 3.1 million tons of metallurgical and steam coal during 2006. Wells operates a preparation plant and processes coal production from the Rivers Edge Mine and contract mines that use continuous mining equipment. The processed coal is loaded on the CSX railroad. Hourly employees at the Wells preparation plant and Rivers Edge Mine are represented by the UMWA.

Federal Business Unit

The Federal Business Unit consists of the Federal No. 2 Mine, near Fairview, West Virginia, and uses longwall and continuous mining equipment to extract coal. The business unit operates a preparation plant which processed and shipped approximately 4.5 million tons of steam coal during 2006. Coal shipped from the Federal No. 2 Mine has sulfur content only slightly above that of medium sulfur coal and has above average heating content for the region. As a result, it is more marketable than some other medium sulfur coals. The CSX and Norfolk Southern railroads jointly serve the mine. Hourly employees at the Federal Business Unit are represented by the UMWA.

Highland Business Unit

The Highland No. 9 Mine, which uses continuous mining equipment, is managed by our Highland Mining Company, LLC subsidiary and is located near Waverly, Kentucky. The mine sold 3.5 million tons of steam coal during 2006. This business unit also operates a preparation plant and barge loading facility. Hourly employees at the Highland No. 9 Mine are represented by the UMWA.

KE Ventures Joint Venture

We own a 73.9% interest in KE Ventures LLC, a joint venture which owns and manages underground mining operations, a preparation plant and barge-and-rail loading facilities near Marmet, West Virginia. The mines are non-union and use continuous mining equipment. The joint venture shipped 2.0 million tons during 2006.

Midwest Operations

Our Midwest Operations consist of 14 wholly-owned mines in the Illinois Basin and are comprised of our Midwest Coal Resources II, LLC, Indian Hill Company, Coulterville Coal Company, LLC, Black Beauty Holding Company, LLC and Arclar LLC subsidiaries. We control approximately 4.2 billion tons of proven and probable coal reserves in the Midwest. In 2006, these operations collectively sold 35.9 million tons of coal, more than any other Midwestern coal producer. We ship coal from these mines primarily to electricity generators in the Midwestern United States and to industrial customers for power generation.

Midwest Coal Resources II, LLC

Midwest Coal Resources II, LLC owns and manages three mines in western Kentucky. Patriot, a surface mine, and Freedom, an underground mine, are located in Henderson County, Kentucky, and sold 1.4 million tons and 1.3 million tons of steam coal, respectively, in 2006. The Big Run underground mine, located in Ohio County, Kentucky, closed in December 2006 due to loss of the mine s sole customer. The mine sold 1.3 million tons of steam coal in 2006. The two underground mines use continuous mining equipment and the surface mine uses truck and shovel equipment. Midwest Coal Resources II, LLC also owns and operates a preparation plant and a coal loading dock. All Midwest Coal Resources II, LLC employees are non-union.

Indian Hill Company

Indian Hill Company, our wholly-owned subsidiary, owns Dodge Hill Holding JV, LLC, which manages Dodge Hill No. 1, an underground mine located in Union County, Kentucky. Dodge Hill No. 1 has non-union employees and sold 1.1 million tons of steam coal in 2006.

Coulterville Coal Company

Coulterville Coal Company, LLC owns the Gateway Mine in Randolph County, located in southwestern Illinois. During 2006, the Gateway Mine sold 2.4 million tons of steam coal. The mine, which has non-union employees, is managed and operated by our wholly-owned subsidiary, Black Beauty Coal Company.

Black Beauty Coal Company

The Black Beauty Coal Company, LLC mines sold 22.5 million tons of compliance, medium sulfur and high sulfur steam coal during 2006. Black Beauty s principal Indiana mines include Air Quality, Farmersburg, Francisco and Somerville. Air Quality is an underground coal mine located near Monroe City, Indiana that sold 2.2 million tons of compliance coal during 2006. Farmersburg is a surface mine located in Vigo and Sullivan counties in Indiana that sold 3.8 million tons of medium sulfur coal during 2006. The Francisco Mine Complex, located in Gibson County, Indiana mines coal by utilizing both surface mining and underground mining methods and sold 3.1 million tons of medium sulfur coal during 2006. The Somerville Mine Complex, also located in Gibson County, sold a total of 8.6 million tons of medium sulfur coal in 2006. Two other surface mines located in Indiana, Viking and Miller Creek, collectively sold 3.1 million tons of medium sulfur coal during 2006.

Black Beauty s Riola Mine Complex is an underground mining facility in eastern central Illinois. The Riola Mine Complex sold 1.7 million tons of medium sulfur coal during 2006. Due to unforeseen geologic conditions, and for the safety of our employees, Black Beauty reoriented its mine plan in 2006 resulting in the closure of the Riola Portal, with all subsequent production coming from the Vermilion Grove Portal. All Black Beauty Coal Company employees are non-union.

Black Beauty owns a 75% interest in United Minerals Company, LLC. United Minerals, which utilizes a non-union workforce, currently acts as a contract miner for Black Beauty on a portion of the Somerville Mine Complex reserves and is a contract operator for Black Beauty at the Evansville River Terminal coal dock located on the Ohio River.

Arclar Company LLC

We operate the Wildcat Hills surface mine and Willow Lake underground mining complex located in Gallatin and Saline counties in southern Illinois. During 2006, these mines sold 2.4 million tons and 3.5 million tons, respectively, of medium sulfur coal that is primarily shipped by barge to downriver utility plants. An underground portal was added to the Wildcat Hills operation in mid-2006. Black Beauty provides a non-union contract workforce to mine the surface reserves at Wildcat Hills. The hourly workforce at the Willow Lake underground mine, which is represented under an International Brotherhood of Boilermakers labor agreement, is supplied by our Big Ridge, Inc. subsidiary. This labor agreement expired in October 2006 and negotiations are continuing for a new labor agreement. The hourly workforce is working under the provisions of the previous labor agreement.

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Australian Mining Operations

In October 2006, we acquired Excel Coal Limited, an independent coal company in Australia, which added three operating mines (Wambo Open-Cut, Metropolitan and Chain Valley), two late development-stage mines (Wilpinjong and Millennium) and a development-stage mine (North Wambo Underground) to our Australia operations. Following the acquisition, we manage six mines in Queensland, Australia, and five mines in New South Wales, Australia, through our wholly-owned subsidiary, Peabody Pacific Pty Limited. During 2006, our Australian operations sold 11.0 million tons of coal, 6.5 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 while 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 0.8 billion tons of proven and probable coal reserves.

Wilkie Creek Mine

The Wilkie Creek Coal Mine, located in Queensland, Australia, is a surface, truck-and-shovel operation. In 2006, the Wilkie Creek Mine sold 2.0 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 2006, we sold 3.5 million tons of metallurgical coal and 0.6 million tons of steam coal from the Burton Mine through the Dalrymple Bay Coal Terminal.

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Millennium Mine

The Millennium Mine, located in Queensland, Australia, is a surface operation utilizing truck-and-shovel mining methods. This mine is expected to begin shipments of metallurgical coal through the Dalrymple Bay Coal Terminal in early 2007, with production targeted at 1.6 million tons. We own an 84.6% interest in the Millennium Mine and manage the operations utilizing a contract miner.

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 2006, the North Goonyella Mine sold 1.2 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 2006, the Eaglefield mine sold 1.4 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 steam coal and a pulverized coal injection (PCI) product, a substitute for metallurgical coal used primarily by steel makers. Shipments through the Port of Gladstone commenced in the first quarter of 2006. During 2006, the Baralaba Mine sold 0.1 million tons of steam coal and 0.1 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. In 2006, the Wambo Open-Cut Mine sold 4.6 million tons of steam coal for the full year and sold 1.3 million tons of steam coal since the acquisition. The coal from this mine was shipped the 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 under development and is expected to begin shipments in mid to late 2007, with production targeted for approximately 3 million tons per year over the next several years. This longwall mining operation plans to produce steam coal and semi-soft metallurgical coal for shipment to customers 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 2006, the Metropolitan Mine sold 1.7 million tons of hard and semi-hard metallurgical coal for the full year and sold 0.5 million tons of this coal since the acquisition. Coal shipments from this mine are to export customers through Port Kembla and to an Australian domestic customer.

Wilpinjong Mine

The Wilpinjong Mine, located in New South Wales, Australia, is a new open-cut mine that was under development until late 2006. The mine is expected to produce 6-7 million tons of thermal coal in 2007 for shipment to export customers through the Port of Newcastle in addition to serving a domestic electricity generator. Coal is mined by a contractor from reserves that we control.

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. The mine sold 0.8 million tons of thermal coal for the full year and sold 0.3 million tons of thermal coal since it was acquired in October 2006. 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.

Carbones del Guasare, S.A.

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 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 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) and all of Transportes Coal-Sea de Venezuela C.A. Cosila owns the Las Carmelitas coal mine development project, which has approximately 30 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 obtained through the Excel acquisition in October 2006.

Resource Management

We hold approximately 10.2 billion tons of proven and probable coal reserves and more than 350,000 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.

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Sales and Marketing

Our sales, trading, brokerage and marketing operations include COALSALES, LLC; COALSALES II, LLC; COALTRADE, LLC and COALTRADE International, LLC. Through our sales, trading, brokerage and marketing departments, 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 emission allowances and provide transportation-related services. As of December 31, 2006, we had 85 employees in our sales, trading, brokerage, marketing and transportation operations, including personnel dedicated to performing market research, contract administration and risk management activities.

International Expansion

In response to growing international markets, we established an international trading group in 2006. This group began trading in international markets in May 2006 and added another operations office in Europe in early 2007. The sales and marketing operations also 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. In 2006, Shenhua Group Corporation Limited and Peabody announced that the two companies have signed a memorandum of understanding to pursue business development opportunities of mutual interest. The agreement formalizes the parties mutual interest in working together in coal and coal-related projects and initiatives. Shenhua Group Corporation Limited is the wholly-state owned parent company of the Hong Kong stock exchange-listed China Shenhua Energy Company Limited.

Long-Term Coal Supply Agreements

We currently have a sales backlog in excess of one billion tons of coal, including backlog subject to price reopener and/or extension provisions, and our coal supply agreements have remaining terms ranging from one to 19 years and an average volume-weighted remaining term of approximately 5 years. For 2006, we sold approximately 90% of our sales volume under long-term coal supply agreements. In 2006, we sold coal to over 400 electricity generating and industrial plants in 20 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. One of our largest coal supply agreements is the subject of ongoing litigation and arbitration, as discussed in Item 3. Legal Proceedings.

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 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. Coal sales under the first five years of the agreement are expected to be in excess of $1 billion. Assumed as part of the Excel Coal Limited acquisition, we have a 19-year coal supply agreement with Macquarie Generation, 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 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, some 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 lower 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, approximately half 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.

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Transportation

Usually coal consumed domestically is 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.

The majority of our sales volume is shipped by rail, 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.

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 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, our Board of Directors approved a project to convert our existing information systems across the major business processes to an integrated information technology system provided by SAP AG. This project will establish a single global information platform for Peabody and will enable standard processes and real-time capabilities in Finance, Materials, Maintenance, Human Resources, Sales, Production, Transportation and Quality across all of our domestic and Australia operations. The project began in the first half of 2006 with development activities, and implementation is targeted to occur mid-2007 in the U.S. and late 2007 to early 2008 for Australia.

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.

We are continuing a major effort to improve 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. A dragline is being refurbished and upgraded in Wyoming with many new design features including a new trapezoidal boom, larger bucket, larger hoist motors and additional drag and swing motors. The upgrade modifications are expected to increase the dragline system capacity by 20% over the original capacity. The dragline is expected to be commissioned near the end of the first quarter of 2007. A large dragline in Arizona was upgraded with many of the same improvements in 2006. All draglines are equipped with stress and performance monitoring equipment.

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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. There are plans to rollout the system to other mining operations. Proprietary software for hand-held Personal Digital Assistant (PDA) devices was developed, and is being used, for safety observations, audits and front-line supervisor reports.

World-class maintenance standards based on condition-based maintenance practices are being implemented at all operations. Use of these techniques is expected to allow us to increase equipment utilization and reduce capital spending by extending the equipment life, while minimizing the risk of premature failures. Lubrication is replaced and work is scheduled on condition rather than time. Benefits from sophisticated lubrication analysis and quality-control include lower lubrication consumption, optimum equipment performance and extended component life. Specialized maintenance reliability software is currently being installed, on a phased schedule, to better predict equipment condition in order to optimize component replacement timing.

Our mines use sophisticated software to schedule and monitor trains, mine and pit blending, quality and customer shipments. The integrated software was developed in-house and provides a competitive tool to differentiate our reliability and product consistency. We are one of the largest users of advanced coal quality analyzers among coal producers, according to the manufacturer of this equipment. These analyzers allow continuous analysis of certain coal quality parameters, such as sulfur content. Their use helps ensure consistent product quality and helps customers meet stringent air emission requirements.

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 2005 Coal Producer Survey, the top 10 coal companies in the United States produced approximately 67% of total domestic coal in 2005. Our principal U.S. competitors are other large coal producers, including Arch Coal, Inc., Rio Tinto Energy America, CONSOL Energy Inc, Foundation Coal Corporation and Massey Energy Company, which collectively accounted for approximately 39% of total U.S. coal production in 2005. Major international competitors include Rio Tinto, Anglo-American PLC and BHP Billiton.

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 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.

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We are continuing to progress on the permitting processes, transmission access agreements and contractor-related activities for developing clean, low-cost mine-mouth generating plants using our surface lands and coal reserves. 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

Our Prairie State Energy Campus (Prairie State) is a planned 1,600 plus-megawatt coal-fueled electricity generation project located in Washington County, Illinois. Prairie State would be fueled by over six million tons of coal each year produced from adjacent underground mining operations. In February 2005, a group of Midwest rural electric cooperatives and municipal joint action agencies entered into definitive agreements to acquire approximately 47% of the project. This group of investors is comprised of Soyland Power Cooperative, Inc. (SPCI) (subsequently assigned to Prairie Power, Inc.), Kentucky Municipal Power Agency (KMPA), Wolverine Power Cooperative, Northern Illinois Municipal Power Agency, Indiana Municipal Power Agency and the Missouri Joint Municipal Electric Utility Commission (MJMEUC). In October 2006, Prairie State entered into agreements with the KMPA, the MJMEUC and the SPCI for the right to purchase an additional 6% equity share of the project. Also in October 2006, we entered an agreement with CMS Enterprises to equally share an expected 30% equity interest in Prairie State and to oversee development and operation of the generating plant. We also signed a letter of intent with Bechtel Power Corporation in October 2006 to provide engineering and procurement services for development of the power-related facilities at Prairie State. The above are all key milestones in the development of Prairie State.

In January 2005, the State of Illinois issued the final air permit for the electric generating station and adjoining coal mine. After an initial appeal, the Illinois Environmental Protection Agency reissued the air permit on April 28, 2005. The same parties who filed the earlier permit challenge filed a new appeal on June 8, 2005. In the third quarter of 2006, the Prairie State Energy Campus received affirmation of the air quality permit from the Environmental Appeals Board of the U.S. Environmental Protection Agency; however, in the fourth quarter of 2006, parties that had previously challenged the permit filed a new appeal with the United States 7th Circuit Court of Appeals.

Thoroughbred Energy Campus

In 2003, the 1,500-megawatt Thoroughbred Energy Campus (Thoroughbred) in Muhlenberg County, Kentucky received a conditional Certificate to Construct from the Commonwealth of Kentucky. We and the Commonwealth of Kentucky defended the air permit granted to Thoroughbred in 2002 as certain environmental groups challenged the permit, and in April 2006, we received a decision affirming the air permit for our Thoroughbred Energy Campus. This milestone allows us to continue advancing the development of that campus. Certain parties subsequently challenged the favorable decision in Kentucky state court. If successfully completed, the Thoroughbred Energy project is expected to utilize approximately six million tons of coal each year.

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 emission coal-fueled power plant. FutureGen is intended to demonstrate advanced coal-based technologies to generate electricity and also produce hydrogen to power fuel cells for transportation and other energy needs. The technology is expected to integrate the capture of carbon emissions with carbon sequestration, helping to address the issue of climate change as energy demand continues to grow worldwide. The alliance announced in December 2005 that it entered into a cooperative agreement with the DOE to develop and site in the United States the cleanest

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coal-fueled power plant in the world with a target of zero emissions, hydrogen production and carbon dioxide sequestration capabilities. Four candidate sites (two in Texas and two in Illinois) are finalists to host FutureGen. The DOE will review the candidate sites in accordance with the National Environmental Policy Act prior to the Alliance s selection of a final site by late-summer 2007.

Btu Conversion

With the increase in domestic demand for natural gas and oil based commodities, we have placed significant attention on determining how we can participate in technologies to economically convert our coal resources. Technology has advanced over the last twenty years to convert coal to natural gas as well as liquids, such as diesel fuel, gasoline and jet fuel.

In October 2005, we reached an agreement to acquire a 30% interest in Econo-Power International Corporation (EPIC). We will invest up to $6 million for the 30% interest and will assist in developing coal supply options for customers of that technology. As of December 31, 2006, we have funded $4.1 million under this agreement and hold a 25.35% interest. EPIC systems use air-blown gasifiers to convert coal into a synthetic gas that is ideal for industrial applications.

In July 2006, we announced that we had entered into 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. Projects would be sited where we have large reserves and would be designed using Rentech s proprietary Fischer-Tropsch coal-to-liquids process. Plant production could range from 10,000 to 30,000 barrels of fuel per day (bpd). A 10,000 bpd plant would use 2 to 3 million tons of coal annually and a 30,000 bpd plant would use 6 to 9 million tons of coal annually, dependent on the quality of coal. With more than 10.2 billion tons of reserves, we have numerous sites in the United States that have potential for Btu Conversion projects.

Coalbed Methane and Oil and Gas Properties

We continue to evaluate the potential of the coalbed methane business and will make acquisitions, develop our properties, enter into joint operating agreements and ventures with other companies or make property sales as appropriate. Our subsidiary, Peabody Natural Gas, LLC, produces coalbed methane and conventional gas and oil from its operations in the Southern Powder River Basin near the Caballo Mine and North Antelope Rochelle Mine. As of December 31, 2006, we operated 62 coalbed methane and conventional gas and oil wells with net production of approximately 1.7 million cubic feet per day. We are evaluating coalbed methane resources in several deep coal seams in the Powder River Basin and continue to evaluate coalbed methane and shale gas opportunities in southern Illinois and Indiana, western Kentucky, and West Virginia.

Certain Liabilities

We have significant long-term liabilities for reclamation (also called asset retirement obligations), work-related injuries and illnesses, pensions and retiree health care. In addition, labor contracts with the UMWA 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.

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 the Surface Mining Control and Reclamation Act. Expense (which includes liability accretion and asset amortization) for the years ended December 31, 2006, 2005 and 2004 was $40.1 million, $35.9 million, and $42.4 million, respectively. As of December 31, 2006, our asset retirement obligations of $423.0 million included $354.0 million related to locations with active mining operations and $69.0 million related to locations that are closed or inactive.

Workers Compensation. These liabilities represent the actuarial estimates for compensable, work-related injuries (traumatic claims) and occupational disease, primarily black lung disease (pneumoconiosis). The Federal Black Lung Benefits Act requires employers to pay black lung awards to current and former employees who filed claims after June 1973. Workers compensation liabilities were $264.4 million as of December 31, 2006, $31.0 million of which was a current liability. The adoption of the Financial Accounting Standards Board s recently issued Statement of Financial Accounting Standard (SFAS) No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS No. 158) on December 31, 2006 resulted in a decrease to our workers compensation liability of $4.5 million and a decrease to accumulated other comprehensive loss of $2.7 million, net of tax. Therefore, in accordance with SFAS No. 158, the $264.4 million liability as of December 31, 2006 represented the accumulated obligation related to our workers compensation plans, including unrecognized actuarial gains. Expense for the years ended December 31, 2006, 2005 and 2004 was $44.0 million, $56.1 million and $59.2 million, respectively.

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. Beginning on January 1, 2008, new minimum funding standards will be required by the Pension Protection Act of 2006. Pension-related liabilities were $128.6 million as of December 31, 2006, $1.3 million of which was a current liability. The adoption of SFAS No. 158 on December 31, 2006 resulted in an increase to our pension-related liability of $14.9 million and an increase to accumulated other comprehensive loss of $8.0 million, net of tax. Therefore, in accordance with SFAS No. 158, the $128.6 million liability as of December 31, 2006 represented the projected benefit obligation associated with our pension plans, including unrecognized actuarial losses and prior service cost, less the fair value of pension plan assets. Expense for the years ended December 31, 2006, 2005 and 2004 was $26.3 million, $38.7 million and $28.5 million, respectively.

Retiree Health Care. Consistent with 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 $1.45 billion as of December 31, 2006, $82.6 million of which was a current liability. The adoption of SFAS No. 158 on December 31, 2006 resulted in an increase to our retiree health care liabilities of $395.5 million and an increase to accumulated other comprehensive loss of $237.3 million, net of tax. Therefore, in accordance with SFAS No. 158, the $1.45 billion liability as of December 31, 2006 represented the accumulated benefit obligations of our retiree health care liabilities, including any unrecognized actuarial losses and prior service cost. Expense for the years ended December 31, 2006, 2005 and 2004 was $108.4 million, $99.0 million and $58.4 million, respectively.

A second category of retiree health care obligations represents the liability for future contributions to certain multi-employer health funds. 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 our retired former employees 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 Fund, 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.

On December 20, 2006, President Bush signed the Surface Mining Control and Reclamation Act Amendments of 2006 (the 2006 Act). Prior to the enactment of this new law, federal statutes required certain Peabody subsidiaries to make contributions to two coal industry retiree health funds for costs of orphans who are retirees and their dependents of bankrupt companies that defaulted in providing their health care benefits. These orphan benefits will be the responsibility of the federal government on a phased-in basis. The legislation authorizes $490 million per year in general fund revenues to pay for these and other benefits under the bill. In addition, future interest from the federal Abandoned Mine Land (AML) trust fund and previous unused interest from the AML trust fund will be available to offset orphan retiree health care costs. Under current projections from the health funds, these available resources are more than adequate to cover all anticipated costs of orphan retirees. These amounts are also in addition to any amounts that may be appropriated by Congress at its discretion. The legislation also reduces AML fees currently paid by us on coal production. Beginning in October 2007, those fees will be reduced by ten percent from current levels for five years, and then twenty percent from current levels for ten years, at which point the authority to collect fees will expire.

The 2006 Act specifically amended the federal laws establishing the Combined Fund, the 1992 Benefit Plan and the 1993 Benefit Plan. The 2006 Act provides new and additional funding to all three programs, subject to the limitations described below. The 2006 Act guarantees full funding of all beneficiaries in the Combined Fund by supplementing the annual transfers of interest earned on the AML trust fund. The 2006 Act further provides funding for the annual orphan health costs under the 1992 Benefit Plan on a phased-in basis: 25%, 50% and 75% in the years 2008, 2009 and 2010, respectively. Thereafter, federal funding will pay for 100% of the orphan health costs. The coal producers that signed the 1988 labor agreement, including some of our subsidiaries, remain responsible for the costs of the 1992 Benefit Plan in 2007. The 2006 Act also included the 1993 Benefit Plan as one of the statutory funds and authorizes the trustees of the 1993 Benefit Plan to determine the contribution rates through 2010 for pre-2007 beneficiaries. During calendar years 2008 through 2010, federal funding will pay a portion of the 1993 Benefit Plan s annual health costs on a phased-in basis; 25%, 50% and 75% in the years 2008, 2009 and 2010, respectively. The 1993 Benefit Plan trustees have set a $2.00 per hour statutory contribution rate for 2007. Under the 2006 Act, these new and additional federal expenditures to the Combined Fund, 1992 Benefit Plan, 1993 Benefit Plan and certain Abandoned Mine Land payments to the states and Indian tribes are collectively limited by an aggregate annual cap of $490 million. To the extent that (i) the annual funding of the programs exceeds this amount (plus the amount of interest from the AML trust fund paid with respect to the Combined Benefit Fund), and (ii) Congress does not allocate additional funds to cover the shortfall, contributing employers and affiliates, including some of our subsidiaries, would be responsible for the additional costs. Those of our subsidiaries that have agreed to the 2007 National Bituminous Coal Wage Agreement will pay $0.50 per hour worked to the 1993 Benefit Plan to provide benefits for post 2006 beneficiaries. To the extent the $0.50 per hour payment exceeds the amount needed for this purpose, the difference will be credited against the $2.00 per hour statutory payment.

Obligations to the United Mine Workers of America Combined Fund were $30.8 million as of December 31, 2006, $5.2 million of which was a current liability. Expense for the years ended December 31, 2006, 2005 and 2004 was $2.5 million, $0.9 million and $4.9 million, respectively. The 1992 Benefit Fund and the 1993 Benefit Fund are expensed as payments are made and no liability is recorded other than amounts due and unpaid. Expense related to these funds was $5.7 million, $4.0 million and $4.4 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Employees

As of December 31, 2006, we had approximately 9,200 employees. Approximately 60% of our hourly employees were non-union as of December 31, 2006 and they generated 86% of our 2006 coal production. Relations with our employees and, where applicable, organized labor are important to our success.

We opened training centers in the eastern, 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 serve as centers for dissemination of 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

Approximately 66% of our U.S. miners are non-union and are employed in the states of Wyoming, Colorado, Indiana, New Mexico, Illinois and Kentucky. The UMWA represented approximately 26% of our subsidiaries hourly employees, who generated 11% of our U.S. production during the year ended December 31, 2006. An additional 5% of our hourly employees are represented by labor unions other than the UMWA. These employees generated 1% of our production during the year ended December 31, 2006. Hourly workers at our mine in Arizona are represented by the UMWA under the Western Surface Agreement of 2000, which is effective through September 1, 2007. Our union workforce east of the Mississippi River is primarily represented by the UMWA. The UMWA-represented workers at one of our eastern mines operate under a contract that expires on December 31, 2007. The remainder of our UMWA-represented workers in the east operate under a recently signed, five-year labor agreement expiring December 31, 2011. This contract replaced a contract that had expired on December 31, 2006 and mirrors the 2007 National Bituminous Coal Wage Agreement.

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 hourly production employees. As of December 31, 2006, our Australian hourly employees were approximately 9% of our hourly workforce and generated 2% of our total production in the year then ended. The labor agreement at our Wilkie Creek Mine was renewed in June 2006 and that agreement expires in June 2009. The North Goonyella Mine operates under an agreement due to expire in 2008, and the Metropolitan Mine operates under an agreement that expires in June 2007.

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.

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Mine Safety and Health

Our goal is to achieve excellent safety and health performance. We measure our progress in this area primarily through the use of accident frequency rates. 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 the establishment of safety standards; 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 record.

Our safety performance in 2006, as measured by accident frequency rates, was 38% better than the U.S. average for our industry. During 2006, we achieved our vision of zero accidents at 12 of our facilities, which contributed to our second best year ever in safety. We received multiple safety awards during the year, including our third consecutive Holmes Safety Association s Green River Council award at our Big Run Mine in Ohio County, Kentucky; our second consecutive Safe Sam award at our North Antelope Rochelle Mine, Wyoming s safest mine and our most productive; and the Mountaineer Guardian Award from the West Virginia Office of Miners Health, Safety and Training and the West Virginia Coal Association for outstanding safety achievement at our Federal No. 2 underground mine. 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. See the Employees section above for a discussion of our Workforce of the Future initiative.

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 rescuers in the escape routes leading to the surface. Our cost for the additional SCSR devices, storage boxes, training units and lifelines to assist miners in potentially dangerous escape routes has exceeded $10 million. Our evacuation training programs have been expanded to include more comprehensive training with the SCSR devices and frequent tours of the escape routes in their entirety. The Miner Act also requires installation of two-way communications systems that allows communication between rescue workers and trapped miners following an accident as mine operators must have the ability to locate each miner s last known position immediately before and after a disaster occurs. Since these technologies are not yet available, our underground mines currently locate miners with existing mine communications telephone systems and we are working with the National Institute for Occupational Safety and Health and several manufacturers to develop new communications and location systems. The projected costs for a new system are approximately $10 million. We are also constructing rescue chambers for trapped miners who are unable to use escape routes due to fires or obstructions and providing at least two mine rescue teams located within thirty minutes of each mine. See risks inherent to mining in Item 1A. Risk Factors.

Most of the states in which we operate have state programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry is perhaps the most comprehensive and pervasive system for protection of employee health and safety affecting any segment of U.S. industry. As a result of the increase in fatal accidents primarily at U.S. underground mines, several states have adopted new safety regulations and the Mine Safety and Health Administration has passed numerous emergency regulations including emergency notification and response plans, increased fines for violations and added mine rescue coverage requirements. While these changes have had a significant effect on our operating costs, our U.S. competitors with underground mines are subject to the same degree of regulation.

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Black Lung

In the United States, 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.

Coal Industry Retiree Health Benefit Act of 1992

The Coal Industry Retiree Health Benefit Act of 1992 (Coal Act) provides for the funding of health benefits for certain UMWA retirees. The Coal Act established the Combined Fund into which signatory operators and related persons are obligated to pay annual premiums for beneficiaries. The Coal Act also created a second benefit fund, the 1992 Benefit Plan, for miners who retired between July 21, 1992, and September 30, 1994, and whose former employers are no longer in business. Annual payments made by certain of our subsidiaries under the Coal Act totaled $13.5 million, $6.3 million $19.3 million, respectively, during the years ended December 31, 2006, 2005 and 2004.

The 2006 Act specifically amended the federal laws establishing the Combined Fund, the 1992 Benefit Plan and the 1993 Benefit Plan. The 2006 Act provides new and additional funding to all three programs, subject to the limitations described below. The 2006 Act guarantees full funding of all beneficiaries in the Combined Fund by supplementing the annual transfers of interest earned on the AML trust fund. The 2006 Act further provides funding for the annual orphan health costs under the 1992 Benefit Plan on a phased-in basis: 25%, 50% and 75% in the years 2008, 2009 and 2010, respectively. Thereafter, federal funding will pay for 100% of the orphan health costs. The coal producers that signed the 1988 labor agreement, including some of our subsidiaries, remain responsible for the costs of the 1992 Benefit Plan in 2007. The 2006 Act also included the 1993 Benefit Plan as one of the statutory funds and authorizes the trustees of the 1993 Benefit Plan to determine the contribution rates through 2010 for pre-2007 beneficiaries. During calendar years 2008 through 2010, federal funding will pay a portion of the 1993 Benefit Plan s annual health costs on a phased-in basis; 25%, 50% and 75% in the years 2008, 2009 and 2010, respectively. The 1993 Benefit Plan trustees have set a $2.00 per hour statutory contribution rate for 2007. Under the 2006 Act, these new and additional federal expenditures to the Combined Fund, 1992 Benefit Plan, 1993 Benefit Plan and certain Abandoned Mine Land payments to the states and Indian tribes are collectively limited by an aggregate annual cap of $490 million. To the extent that (i) the annual funding of the programs exceeds this amount (plus the amount of interest from the AML trust fund paid with respect to the Combined Benefit Fund), and (ii) Congress does not allocate additional funds to cover the shortfall, contributing employers and affiliates, including some of our subsidiaries, would be responsible for the additional costs. Those of our subsidiaries that have agreed to the 2007 National Bituminous Coal Wage Agreement will pay $0.50 per hour worked to the 1993 Benefit Plan to provide benefits for post 2006 beneficiaries. To the extent the $0.50 per hour payment exceeds the amount needed for this purpose, the difference will be credited against the $2.00 per hour statutory payment.

Our subsidiaries have been billed a retroactive assessment in the amount of $7.4 million for periods prior to October 1, 2003 as well as an increase of $0.7 million for the period from October 1, 2003 through September 30, 2004 and $0.6 million from October 2004 through August 15, 2005 as a result of the Social Security Administration s premium recalculation. These amounts were paid as required by the Combined Fund Trustees, but were paid under protest. In August 2005, a federal district court in Maryland ruled in favor of our subsidiaries, and we suspended payments to the Combined Fund to recoup our overpayment. On December 2, 2005, the same federal court granted a stay of payment recoupment, and we paid to the Combined Fund the amount we recouped. In December 2006, the Fourth Circuit Court of Appeals upheld the Maryland district court s finding that the Social Security Administration s premium calculation was unlawful. Our subsidiaries are pursuing a refund of the $8 million overpayment made to the Combined Fund.

Environmental Laws

We are subject to various federal, state and foreign 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 $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 substantial matters that pose a risk to maintaining our existing mining permits or hinder our ability to acquire future mining permits. It is our policy to comply in all material respects with the requirements of the Surface Mining Control and Reclamation Act 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 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.

Title IV of the Clean Air Act places limits on sulfur dioxide emissions from electric power generation plants. The limits set baseline emission standards for these facilities. Reductions in emissions occurred in Phase I in 1995 and in Phase II in 2000 and apply to all coal-based power plants. The affected electricity generators have been able to meet these requirements by, among other ways, switching to lower sulfur fuels; installing pollution control devices, such as flue gas desulfurization systems, which are known as scrubbers; reducing electricity generating levels; or purchasing sulfur dioxide emission allowances. Emission sources receive these sulfur dioxide emission allowances, which can be traded or sold to allow other units to emit higher levels of sulfur dioxide. Title IV also required that certain categories of coal-based electric generating stations install certain types of nitrogen oxide controls. Major changes in Title IV were recently promulgated in the Clean Air Interstate Rule (CAIR) discussed below.

In July 1997, the EPA adopted new, more stringent National Ambient Air Quality Standards for very fine particulate matter (PM2.5) and ozone. As a result, 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. State and federal regulations relating to implementation of the new air quality standards may restrict our ability to develop new mines or could require us to modify our existing operations.

In December 2003, the EPA proposed the CAIR, which is designed to help bring the eastern half of the United States into compliance with the National Ambient Air Quality Standards for fine particulates and ozone. The rule became final in March 2005 and will require further reduction of sulfur dioxide and nitrogen oxide emissions from electricity generating plants in 28 states and the District of Columbia although it is being challenged. Once fully implemented, the rule will reduce sulfur dioxide from power plants by approximately 73% from 2003 levels and, by 2015, nitrogen oxide emissions by approximately 61% from 2003 levels. CAIR is currently under review in court on a number of grounds, including the assertion that the regulation is insufficiently stringent.

On September 21, 2006, EPA promulgated new National Ambient Air Quality Standards revising and updating the 1997 particulate matter standards. The new regulations made the 24-hour standard for PM2.5 more stringent but left the annual PM2.5 standard unchanged. It 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 have an effect on the use of coal for electric generation, but it is impossible at this time to quantify that effect. Lawsuits seeking to compel EPA to adopt more stringent standards both for PM2.5 and PM10 have been filed and are pending in court. It is not possible to determine the chances of success for those lawsuits.

The Clean Air Act also requires electricity generators that currently are major sources of nitrogen oxide in moderate or higher ozone non-attainment areas (areas where the air quality does not meet acceptable standards) to install reasonably available control technology for nitrogen oxide, which is a precursor of ozone. In 1997, the EPA promulgated the final NOx SIP Call rules that require coal-fueled power plants in 19 eastern states and Washington, D.C. to make substantial reductions in nitrogen oxide emissions. These states were required to submit their Phase II SIPs by April 2005. Two additional states, Georgia and Missouri, were required to submit a complete NOx SIP by April 2005 to address affected portions of their states. In August 2005, EPA stayed the applicability of the NOx SIP Call to Georgia, although the stay may be reconsidered. Installation of additional control measures required under the final rules has made and will continue to make it more costly to operate coal-based electricity generating plants.

The Justice Department, on behalf of the EPA, has filed a number of lawsuits since November 1999, alleging that 12 electricity generators violated the new source review provisions of the Clean Air Act Amendments at power plants in the midwestern and southern United States. Six electricity generators have announced settlements with the Justice Department requiring the installation of additional control equipment on selected generating units, and at least one generator has received a favorable court decision. If the remaining electricity generators are found to be in violation, they could be subject to civil penalties and be required to install the required control equipment or cease operations. One of the currently pending enforcement cases is now before the U.S. Supreme Court, with a decision expected shortly. Another of these cases was recently decided adversely to the utility, and the utility has asked the Supreme Court to review the case. 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 have the ability to supply coal from various regions to meet any new coal requirements.

In 2002 and again in 2003, EPA promulgated new regulations clarifying and modifying its new source review regulations, including with respect to electric generation sources that utilize coal. These regulations have been litigated and partially remanded to EPA, which has proposed new regulations and is considering proposing others. There is also ongoing litigation concerning aspects of the regulations. These regulations could affect the pending new source review enforcement cases, whether additional cases are brought, and the extent to which other existing coal-based electric generating units may undertake repairs, replacements and modifications without triggering a requirement to install new pollution control equipment. It is difficult to determine at this point the exact configuration of the final new source review regulations that ultimately will emerge and the impact they will have on the utilization of coal for electric generation.

The Clean Air Act set a national goal of the prevention of any future, and the remedying of any existing, impairment of visibility in 156 national parks and wilderness areas across the U.S. Under regulations issued by the EPA in 1999, states were required to consider setting a goal of restoring natural visibility conditions in Class I areas in their states by 2064 and to explain their reasons to the extent they determine not to adopt this goal. The state plans must require the application of Best Available Retrofit Technology (BART) after 2010 on certain electric generating stations reasonably anticipated to cause or contribute to regional haze which impairs visibility in these areas. The extent and nature of these BART requirements have been the subject of litigation. As a result of the litigation, EPA finalized amendments to the 1999 BART regulations in June 2005. EPA included in the amendments guidelines for states to use in determining which facilities must install controls and the types of controls the facilities must use. States are required to develop their implementation plans by December 2007. For electric generating units subject to CAIR in states that adopt the CAIR cap and trade program for sulfur dioxide and NOx, the state is allowed to apply CAIR controls as a substitute for those required by BART. The EPA regional haze regulations may affect other (non-BART) sources to the extent determined necessary to make reasonable progress towards the national visibility improvement goal. Also, five western states

have elected an option offered by the EPA of regulating visibility-impairing emissions through a regional rather than a source-by-source approach. However, this option was litigated and the states rules were invalidated. On October 13, 2006, EPA promulgated new regulations that may allow these western states and possibly others to adopt a regional approach. The EPA s regional haze regulations could cause our customers to install equipment to control sulfur dioxide and nitrogen oxide emissions. The requirement to install control equipment could affect the amount of coal supplied to those customers if they decide to switch to other sources of fuel to lower emission of sulfur dioxide and nitrogen oxide.

In 2005, the EPA adopted the Clean Air Mercury Rule (CAMR) to permanently cap and reduce nationwide mercury emissions from coal-fired power plants. When fully implemented, and after the appeals have been resolved, the rule will reduce mercury emissions by nearly 70%. CAMR establishes standards of performance limiting mercury emissions from new and existing power plants and creates a cap-and-trade program, which will reduce emissions in two phases. When fully implemented, the cap on mercury emissions will be 15 tons per year. Some states have adopted rules that are more stringent than the federal program and other states are considering such rules. Implementation of the federal program or the more stringent state programs could cause our customers to switch to other fuels to the extent it would be economically preferable for them to do so, and could impact the completion or success of our generation development projects. CAMR is currently under review in court on a number of grounds, including the assertion by a number of states and environmental groups that the regulation is insufficiently stringent.

Legislation that would reduce emissions of sulfur dioxide, nitrogen oxide and mercury and other greenhouse gases in phases has been introduced in Congress. No such legislation has passed either house of Congress. If this type of legislation were enacted into law, it 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 emission of sulfur dioxide, nitrogen oxide, mercury and carbon dioxide.

A small number of states have either proposed or adopted legislation or regulations limiting emissions of sulfur dioxide, nitrogen oxide and mercury from electric generating stations. A smaller number of states have also proposed to limit emissions of carbon dioxide from electric generating stations, with California recently having adopted legislation and regulations requiring that all fossil-fueled generation in the state or sold into the state meet a greenhouse gas performance standard that coal-based generation cannot meet without capturing and sequestering a significant amount of carbon dioxide emissions. Limitations imposed by states on emissions of any of these four substances from electric generating stations could result in fuel switching by the generators if they determined it to be economically preferable to do so.

The U.S. Supreme Court in November 2006 heard oral arguments in a case seeking to establish that EPA has authority to regulate carbon dioxide emissions as a pollutant under the Clean Air Act. A decision is expected early this year. It is too soon to speculate on whether a decision in that case could cause EPA to issue carbon dioxide regulations and, if so, 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.

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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,

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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.

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. Surface rights are typically acquired directly from landowners and, in the absence of agreement, there is an arbitration provision in the mining law.

COAL21 Fund

Our subsidiary, Peabody Pacific, has committed to pay up to a maximum of A$0.20/tonne (approximately US$0.15/tonne) of coal sales for a period of five years to the Australian COAL21 Fund. The COAL21 Fund is a voluntary coal industry fund to support clean coal technology demonstration projects and research in Australia. All major coal companies in Australia have committed to this fund. The commitment to pay starts on April 1, 2007 with a levy of A$0.10/tonne of coal sales. This levy is expected to rise to A$0.20/tonne on July 1, 2007.

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.

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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 provide 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.

Global Climate Change

Legislation was introduced in Congress in 2006 to reduce greenhouse gas emissions in the United States. Such or similar federal legislative action could be taken in 2007 or later years. In addition, a number of states in the United States have taken steps to regulate greenhouse gas emissions. For example, seven northeastern states (New York, Vermont, New Hampshire, Maine, Connecticut, Delaware and New Jersey) entered into the Regional Greenhouse Gas Initiative (RGGI) agreement in December 2005 to reduce carbon dioxide emissions from power plants, and in August 2006 finalized a model rule to help implement the agreement; Maryland has approved legislation that may result in inclusion in the RGGI in 2007; in August 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. Greenhouse gas intensity measures the ratio of greenhouse gas emissions, such as carbon dioxide, to economic output. Passage of regulations regarding greenhouse gas emissions by the United States or other actions to limit carbon dioxide emissions could result in fuel switching, from coal to other fuel sources, by electric generators.

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 Australian Federal Government has not signed the Kyoto Protocol but has indicated interest in meeting the emissions reduction requirements of the protocol. No legislation currently exists that restricts or requires reduction in greenhouse emissions within Australia. The Australian Federal Government has created significant incentives for companies that are large energy users. The New South Wales State Government requires certain businesses to prepare an Energy Reduction Plan and is considering introducing mandatory emissions reporting for all coal mines. None of these programs mandate any greenhouse gas emission or energy usage reduction, but seek disclosure of current emissions and voluntary reduction.

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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. 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.

If a substantial portion of our long-term coal supply agreements terminate, our revenues and operating profits could suffer if we were 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, 2006, 90% of our sales volume was sold under long-term coal supply agreements. At December 31, 2006, our coal supply agreements had remaining terms ranging from one to 19 years and an average volume-weighted remaining term of approximately 5 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, 2006, we derived 22% of our total coal revenues from sales to our five largest customers. At December 31, 2006, we had 123 coal supply agreements with these customers expiring at various times from 2007 to 2016. 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, 2006, 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. We are also susceptible to port congestion and demurrage fees. In Australia, we export our Queensland production from Dalrymple Bay Coal Terminal and the Ports of Gladstone and Brisbane. We export our New South Wales production from the Ports of Newcastle and Kembla.

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.

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. In addition, significant legislation mandating specified benefits for retired coal miners affects our industry. 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. The majority of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser s plant or results in specified increases in the cost of coal or its use. These factors and legislation, if enacted, could have a material adverse effect on our financial condition and results of operations.

According to the Department of Energy s Energy Information Administration, Emissions of Greenhouse Gases in the United States 2003, coal accounts for 31% of greenhouse gas emissions in the United States, and efforts to control greenhouse gas emissions could result in reduced use of coal if electricity generators switch to lower carbon sources of fuel. Legislation was introduced in Congress in 2006 to reduce greenhouse gas emissions in the United States. Such or similar federal legislative action could be taken in 2007 or later years (see additional discussion in Item 1 under the heading Global Climate Change). Further developments in connection with legislation, regulations or other limits on greenhouse emissions, both in the United States and in other countries where we sell coal, could have a material adverse effect on our financial condition or 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.

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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 $1.45 billion as of December 31, 2006, $82.6 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 could increase our obligations to provide these or additional benefits.

We are party to an agreement with the Pension Benefit Guaranty Corporation (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, 2006.

In addition, certain of our subsidiaries participate in two defined benefit multi-employer pension funds that were established as a result of collective bargaining with the UMWA pursuant to the National Bituminous Coal Wage Agreement as periodically negotiated. The UMWA 1950 Pension Plan provides pension and disability pension benefits to qualifying represented employees retiring from a participating employer where the employee last worked prior to January 1, 1976. This is a closed group of beneficiaries with no new entrants. The UMWA 1974 Pension Plan provides pension and disability pension benefits to qualifying represented employees retiring from a participating employer where the employee last worked after December 31, 1975. In December 2006, the 2007 National Bituminous Coal Wage Agreement was signed, which required funding of the 1974 Pension Plan through 2011 under a phased funding schedule. The funding is based on an hourly rate for certain UMWA workers. Under the labor contract, the per hour funding rate increased from zero to $2.00 in 2007 and increased each year thereafter until reaching $5.50 in 2011. Although our subsidiaries are not a party to that labor agreement, they are required to contribute to the 1974 Pension Plan at the new hourly rates. During 2006, represented employees subject to the new rate worked a total of approximately four million hours.

Contributions to these funds could increase as a result of future collective bargaining with the UMWA, a shrinking contribution base as a result of the insolvency of other coal companies who currently contribute to these funds, lower than expected returns on pension fund assets, higher medical and drug costs or other funding deficiencies.

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 our retired former employees 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), which was enacted in December 2006, amended the federal laws establishing the Combined Fund, 1992 Benefit Plan and the 1993 Benefit Plan. Among other things, the 2006 Act guarantees full funding of all beneficiaries in the Combined Fund, provides funds on a phased-in basis for the 1992 Benefit Plan, and authorizes the trustees of the 1993 Benefit Plan to determine the contribution rates through 2010 for pre-2007 beneficiaries. The new and additional federal expenditures to the Combined Fund, 1992 Benefit Plan, 1993 Benefit Plan and certain Abandoned Mine Land payments to the states and Indian tribes are collectively limited by an aggregate annual cap of $490 million. To the extent that (i) the annual funding of the programs exceeds this amount (plus the amount of interest from the AML trust fund paid with respect to the Combined Benefit Fund), and (ii) Congress does not allocate additional funds to cover the shortfall, contributing employers and affiliates, including some of our subsidiaries, would be responsible for the additional costs.

Based upon the enactment of the Medicare Prescription Drug, Improvement and Modernization Act of 2003, we estimated future cash savings which allowed us to reduce our projected postretirement benefit obligations and related expense. Failure to achieve these assumed future savings under all benefit plans could adversely affect our financial condition, results of operations and cash flows.

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, 2006, 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 the price or our production of metallurgical coal could decrease our anticipated profitability.

We have annual capacity to produce approximately 15 to 18 million tons of metallurgical coal. Prices for metallurgical coal at the end of 2005 and during 2006 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 will be reduced in 2007.

The majority of our 2007 metallurgical coal production will be priced during the first quarter of 2007; however, early indications are that prices will be down from historical highs. As a result, a decrease in metallurgical coal prices 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, 2006, our total indebtedness was $3.26 billion, and we had $1.29 billion of available borrowing capacity under our revolving credit facility. The indentures governing the convertible debentures and senior notes do not limit the amount of indebtedness that we may issue, and the indentures governing our other 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 of, and interest on, our indebtedness, thereby reducing the availability of the cash flow to fund working capital, capital expenditures, research and development or other general corporate uses;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, 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.

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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, 2006, we had $685.2 million of self bonds in place primarily for our reclamation obligations. As of December 31, 2006, we also had outstanding surety bonds with third parties and letters of credit of $1.09 billion, of which $445.6 million was for post-mining reclamation, $188.5 million related to workers compensation obligations, $119.4 was for retiree healthcare obligations, $104.2 million was for coal lease obligations, and $236.0 million was for other obligations, including collateral for surety companies and bank guarantees, road maintenance, and performance guarantees. 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

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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 outstanding 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 contract miner or 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.

Recently, certain of our brokerage sources and contract miners in the United States have experienced adverse geologic mining, escalated operating costs and/or financial difficulties that have made their delivery of coal to us at the contracted price difficult or uncertain. In some instances, the contract miners and third-party suppliers have suspended mining operations, and it has become increasing difficult to identify and retain contract workers. Our profitability or exposure to loss on transactions or relationships such as these is dependent upon the reliability (including financial viability) and price of the third-party supply, our obligation to supply coal to customers in the event that adverse geologic mining conditions restrict deliveries from our suppliers, our willingness to participate in temporary cost increases experienced by our third-party coal suppliers, our ability to pass on temporary cost increases to our customers, the ability to substitute, when economical, third-party coal sources with internal production or coal purchased in the market, and other factors.

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. Recently, the coal industry experienced lower demand as electricity usage was at lower than historical growth levels. Therefore, as of December 2006, total coal inventories of 130 to 140 million tons at generators were above the five-year average.

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

As of December 31, 2006, we had approximately 9,200 employees. As of December 31, 2006, approximately 40% of our hourly employees were represented by unions and they generated approximately 14% of our 2006 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 66% of our U.S. miners are non-union and are employed in the states of Wyoming, Colorado, Indiana, New Mexico, Illinois and Kentucky. The UMWA represented approximately 26% of our subsidiaries hourly employees, who generated 11% of our U.S. production during the year ended December 31, 2006. An additional 5% of our hourly employees are represented by labor unions other than the UMWA. These employees generated 1% of our production during the year ended December 31, 2006. Hourly workers at our mine in Arizona are represented by the UMWA under the Western Surface Agreement of 2000, which is effective through September 1, 2007. Our union workforce east of the Mississippi River is primarily represented by the UMWA. The UMWA-represented workers at one of our eastern mines operate under a contract that expires on December 31, 2007. The remainder of our UMWA-represented workers in the east operate under a recently signed, five-year labor agreement expiring December 31, 2011. This contract replaced a contract that had expired on December 31, 2006 and mirrors the 2007 National Bituminous Coal Wage Agreement.

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 hourly production employees. As of December 31, 2006, our Australian hourly employees were approximately 9% or our hourly workforce and generated 2% of our total production in the year then ended. The labor agreement at our Wilkie Creek Mine was renewed in June 2006 and that agreement expires in June 2009. The North Goonyella Mine operates under an agreement due to expire in 2008, and the Metropolitan Mine operates under an agreement that expires in June 2007.

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. We do not have key person life insurance to cover our executive officers. 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

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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 resources, and it is challenging to locate resources 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 $225.0 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 of 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.

The extent to which we are able to successfully integrate the newly acquired Excel operations and successfully complete the development of the new mine sites acquired from Excel will have a bearing on our future financial results.

The process of integrating the operations of the Excel coal mines could cause an interruption of, or loss of momentum in, the activities of the business or the development of new mines. We will need to make significant capital expenditures to utilize and maintain the assets we acquired in the Excel acquisition. There are currently three development-stage mines, two of which are scheduled to begin production in early 2007. Delays in optimizing the operations of the development-stage mines, and to a lesser extent the existing Excel operations, could impact our future financial results. Additionally, our ability to integrate and manage the Excel operations will have a direct bearing on the realization of anticipated cost savings and synergies. Further, we may encounter unanticipated risks associated with the Excel acquisition.

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 recently opened a business development, sales and marketing office in Beijing, China and an international trading group in our trading and brokerage operations. 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 domestic 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 2006, the Paso Diablo Mine contributed $28.0 million to segment Adjusted EBITDA in Corporate and Other Adjusted EBITDA (see Item 7) and paid a dividend of $18.2 million. At December 31, 2006, our investment in Paso Diablo was $60.1 million, recorded in Investment 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. The projects we are currently pursuing 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. 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 extent of our success in converting our current information systems to our new enterprise resource planning system will directly impact our ability to perform functions critical to our day-to-day business.

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 project began in the first quarter of 2006 and certain phases of implementation are expected to be completed in 2007. The successful conversion of our information technology systems will have direct bearing on our ability to perform certain day-to-day functions critical to our business, including billing, processing invoices, certain Treasury functions, recordkeeping and financial reporting.

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

None.

Item 2. ***Properties.***

Coal Reserves

We had an estimated 10.2 billion tons of proven and probable coal reserves as of December 31, 2006. An estimated 9.4 billion tons of our proven and probable coal reserves are in the United States and 0.8 billion tons are in Australia. Forty-three percent of our reserves, or 4.4 billion tons, are compliance coal and 57% are non-compliance coal. We own approximately 42% of these reserves and lease property containing the remaining 58%. 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.

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

Operating Regions	Locations	Proven and Probable Reserves as of December 31, 2006(1) Owned Tons	Leased Tons	Total Tons
		(Tons in millions)		
Midwest	Illinois, Indiana and Kentucky	3,270	900	4,170
Powder River Basin	Wyoming and Montana	67	3,400	3,467
Southwest	Arizona and New Mexico	617	363	980
Appalachia	West Virginia and Ohio	249	306	555
Colorado	Colorado	43	184	227
Total United States		4,246	5,153	9,399
Australia	New South Wales		466	466
Australia	Queensland		337	337
Total Proven and Probable Coal Reserves		4,246	5,956	10,202

(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 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 to review estimates of our coal reserves. The most recent of these audits, which was completed in January 2007, included a review of the procedures used by us to prepare our internal estimates, verification of the accuracy of selected property reserve estimates and retabulation of reserve groups according to standard classifications of reliability. This audit confirmed that we controlled approximately 10.2 billion tons of proven and probable reserves as of December 31, 2006.

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. On a regional basis, the expected degree of variance from reserve estimate to tons produced is lower in the Powder River Basin, Southwest and Illinois Basin due to the continuity of the coal seams as confirmed by the mining history. Appalachia, however, has a higher degree of risk due to the mountainous nature of the topography which makes exploration drilling more difficult. Our recovered reserves in Appalachia are less predictable and may vary by an additional one to two percent above the threshold discussed above.

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, 2006, 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 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 leases provide for royalties to be paid to

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the lessor either as a fixed amount per ton or as a percentage of the sales price. Many 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 leases are normally extended by active production on or near the end of the lease term. Leases containing undeveloped reserves may expire or these leases may be renewed periodically. With a portfolio of approximately 10.2 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.

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.

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The following chart provides a summary, by mining complex, of production for the years ended December 31, 2006 and 2005 and 2004, 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 31, 2006				
Geographic Region/Mining Complex	Year Ended Dec. 31, 2006	Year Ended Dec. 31, 2005	Year Ended Dec. 31, 2004	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	Surface	Underground
Appalachia:													
Federal	4.6	4.1	4.9	Steam			31	13,300	31	11	20		31
Big Mountain	2.0	1.9	1.9	Steam	4	30		12,300	34		34		34
Kanawha Eagle[4]	1.9			Steam/Met.	31	22		13,100	53		53		53
Harris	1.6	2.0	3.0	Steam/Met.	5	3		13,800	8		8		8
Rocklick	2.2	2.6	2.0	Steam/Met.	5	7	1	13,100	13		13	3	10
Wells	2.3	2.6	2.6	Steam/Met.	20	29		12,800	49		49		49
Total	14.6	13.2	14.4		65	91	32		188	11	177	3	185
Midwest:													
Highland	3.7	3.8	3.2	Steam			88	11,400	88	31	57		88
Patriot	3.9	4.2	4.1	Steam			41	10,800	41	4	37	3	38
Air Quality	2.2	2.1	1.8	Steam		25	33	10,700	58	5	53		58
Riola/ Vermilion Grove	1.7	2.3	2.3	Steam			19	10,500	19		19		19
Miller Creek	1.6	1.0	0.9	Steam		2	28	10,000	30	29	1	30	
Francisco Surface	2.0	1.8	2.1	Steam			6	10,500	6	2	4	6	
Francisco Underground	1.1	1.2	0.9	Steam			22	10,600	22	3	18		22
Farmersburg	3.8	3.8	4.2	Steam	1	11	95	10,300	107	93	14	107	
Somerville Central	3.5	3.4	3.2	Steam			4	10,300	4	2	2	4	
Somerville North	2.4	2.4	2.1	Steam			7	10,500	7	6	1	7	
	2.5	2.4	2.0	Steam			14	10,000	14	8	6	14	

Somerville South Viking	1.5	1.5	1.5	Steam		1	7	10,700	8		8	8	
Wildcat Hills Surface/Underground	2.4	2.6	2.7	Steam			10	10,300	10	5	5	10	
Willow Lake	3.6	3.7	3.4	Steam			64	11,200	64	48	17		64
Gateway	2.6	0.5		Steam			20	10,300	20	20			20
Dodge Hill	1.1	1.2	1.2	Steam			8	11,100	8	3	5		8
Total	39.6	37.9	35.6		1	39	466		506	259	247	189	317
Powder River Basin:													
North Antelope/ Rochelle	88.6	82.7	82.5	Steam	1,171			8,800	1,171		1,171	1,171	
Caballo	32.8	30.5	26.5	Steam	787	122	22	8,600	931		931	931	
Rawhide	17.0	12.4	6.9	Steam	290	62	55	8,600	407		407	407	
Total	138.4	125.6	115.9		2,248	184	77		2,509		2,509	2,509	
Southwest/ Colorado:													
Black Mesa		3.9	4.8	Steam	10	1		10,600	11		11	11	
Kayenta	8.2	8.2	8.2	Steam	185	82	3	11,000	270		270	270	
Lee Ranch	5.5	5.3	5.8	Steam	20	123	12	10,000	155	88	67	155	
Twentymile	8.6	9.4	6.4	Steam	73			10,800	73	14	59		73
Seneca		1.1	1.5	Steam				NA					
Total	22.3	27.9	26.7		288	206	15		509	102	407	436	73

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	Production				Sulfur Content[2]					As of December 31, 2006			
Geographic Region/Mining Complex	**Year Ended Dec. 31, 2006**	**Year Ended Dec. 31, 2005**	**Year Ended Dec. 31, 2004**	**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**	**Surface**	**Underground**
Australia:													
North Goonyella/ Eaglefield	2.2	2.1	1.7	Met.	48			12,800	48		48	2	46
Metropolitan	0.4			Met.	40			12,700	40		40		40
Wilkie Creek	2.0	1.9	1.4	Steam	223			10,800	223		223	223	
Chain Valley (80.0%)[5]	0.2			Steam	17			11,900	17		17		17
Wambo Open Cut[4]	1.2			Steam	106			12,400	106		106	106	
Burton (95.0%)[5]	4.3	4.4	3.2	Steam/Met.	38			12,400	38		38	38	
Baralaba[4]	0.2			Steam/Met.		2		12,200	2		2	2	
Wilpinjong	0.3			Steam		165		9,900	165		165	165	
Millennium[4]	0.1			Met.	26			12,800	26		26	26	
Total	10.9	8.4	6.3		498	167			665		665	562	103
Total	225.8	213.0	198.9		4,377	4,377	4,377		4,377	4,377	4,377	4,377	4,377

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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, 2006
(Tons in millions)

	Total Tons		Proven and Probable				Sulfur Content[2]			As	Reserve Control		Mining Me	
Seam Location	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	Received Btu per pound[3]	Owned	Leased	Surface	Under
lachia:														
		25	25	19	6	Steam			25	11,300	25			
t inia	188	342	530	310	220	Steam/Met.	141	190	199	13,000	224	306	15	
alachia	188	367	555	329	226		141	190	224		249	306	15	
est:														
ois	113	2,292	2,405	1,190	1,215	Steam	5	38	2,362	10,400	2,195	210	78	2
ana	255	353	608	410	198	Steam	1	40	567	10,300	402	206	258	
ucky	138	1,019	1,157	622	535	Steam		1	1,156	10,800	673	484	105	1
west	506	3,664	4,170	2,222	1,948		6	79	4,085		3,270	900	441	3
er Basin:														
tana		162	162	158	4	Steam	15	117	30	8,600	67	95	162	
ming	2,509	796	3,305	3,226	79	Steam	3,020	183	102	8,700		3,305	3,305	
der r Basin	2,509	958	3,467	3,384	83		3,035	300	132		67	3,400	3,467	
west/ ado:														
ona	281		281	281		Steam	195	83	3	10,900		281	281	
rado	73	154	227	165	62	Steam	139		88	10,600	43	184		
ico	155	544	699	636	63	Steam	91	344	264	9,200	617	82	699	
hwest	509	698	1,207	1,082	125		425	427	355		660	547	980	
alia:														
South es	328	138	466	253	213	Steam/Met.	466			12,400		466	271	

ensland	337		337	104	233	Steam/Met.	335	2		11,200		337	291	
ralia	665	138	803	357	446		801	2				803	562	
Proven robable	10,202	10,202	10,202	10,202	10,202		4,408	998	4,796		10,202	10,202	10,202	10

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(1) Assigned reserves represent recoverable coal reserves that we have committed to mine at locations operating as of December 31, 2006. 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 as-received Btu by region:

Appalachia	6.0%
Midwest:	
Illinois	14.0%
Indiana	15.0%
Kentucky	12.5%
Missouri/ Oklahoma	12.0%
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: Kanawha Eagle 73.9%; 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 30 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. On March 4, 2003, the U.S. Supreme Court issued a ruling in a companion lawsuit involving the Navajo Nation and the United States rejecting the Navajo Nation s allegation that the United States breached its trust responsibilities to the Tribe in approving the coal lease amendments. 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 are in mediation with respect to this litigation and other business issues.

The outcome of this litigation, or the current mediation, 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, 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 $76.8 million and $74.2 million included in Investments and other assets in the consolidated balance sheets as of December 31, 2006 and 2005, respectively.

The outcome of this litigation and arbitration 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, we believe this matter is likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Gulf Power Company Litigation

On June 21, 2006, our subsidiary filed a complaint in the U.S. District Court, Southern District of Illinois, seeking a declaratory judgment upholding its declaration of a permanent force majeure under a coal supply agreement with Gulf Power Company. On June 22, 2006, Gulf Power Company filed a breach of contract lawsuit against our subsidiary in the U.S. District Court, Northern District of Florida, contesting the force majeure declaration and seeking damages for alleged past and future tonnage shortfalls of nearly 5 million tons under the coal supply agreement, which would have expired on December 31, 2007. The parties have filed motions to determine which court will hear the lawsuits. On October 6, 2006, the Florida District Court stayed Gulf Power s lawsuit until the Illinois court decides whether it has jurisdiction.

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, we believe this matter is likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

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Claims and Litigation relating to Indemnities or Historical Operations

Citizens Power

In connection with the August 2000 sale of our former subsidiary, Citizens Power LLC (Citizens Power), we have indemnified the buyer, Edison Mission Energy, from certain losses resulting from specified power contracts and guarantees. During the period that Citizens Power was owned by us, Citizens Power guaranteed the obligations of two affiliates to make payments to third parties for power delivered under fixed-priced power sales agreements with terms that extend through 2008. Edison Mission Energy has stated and we believe there will be sufficient cash flow to pay the power suppliers, assuming timely payment by the power purchasers. There is no pending litigation with respect to these indemnities at this time.

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. Today Gold Fields is 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. 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 is also a defendant, along with other companies, in several personal injury lawsuits involving over 50 children, arising out of the same lead mill operations. Plaintiffs in these actions are seeking compensatory and punitive damages for alleged personal injuries from lead exposure. The first personal injury trial has been scheduled for March 2007 and Gold Fields along with the former affiliate will be the only defendants. In December 2003, the Quapaw Indian tribe and certain Quapaw land owners filed a class action lawsuit against Gold Fields and five other companies. The plaintiffs are seeking compensatory and punitive damages based on a variety of theories. 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, 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

We are subject to applicable federal, state and local environmental laws and regulations in those countries where we conduct operations. Current and past mining operations in the United States are primarily covered by the Surface Mining Control and Reclamation Act of 1977, the Clean Water Act and the Clean Air Act but also include the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA or Superfund), the Superfund Amendments and Reauthorization Act of 1986 and the Resource Conservation and Recovery Act of 1976. Superfund and similar state laws create liability for investigation and remediation in response to releases of hazardous substances in the environment and for damages to natural resources. Under that legislation and many state Superfund statutes, joint and several liability may be imposed on waste generators, site owners and operators and others regardless of fault. These regulations could require us to do some or all of the

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following: (i) remove or mitigate the effects on the environment at various sites from the disposal or release of certain substances; (ii) perform remediation work at such sites; and (iii) pay damages for loss of use and non-use values.

Our policy is to accrue environmental cleanup-related costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures requires an assessment of many factors, including the nature and extent of contamination, the timing, extent and method of the remedial action, changing laws and regulations, advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement. We also assess the financial capability and proportional share of costs of other PRPs and, where allegations are based on tentative findings, the reasonableness of our apportionment. We have not anticipated any recoveries from insurance carriers in the estimation of liabilities recorded in our consolidated balance sheets.

Although waste substances generated by coal mining and processing are generally not regarded as hazardous substances for the purposes of Superfund and similar legislation and are generally covered by the Surface Mining Control and Reclamation Act of 1977, some products used by coal companies in operations, such as chemicals, and the disposal of these products are governed by the Superfund statute. Thus, coal mines currently or previously owned or operated by us, and sites to which we have sent waste materials, may be subject to liability under Superfund and similar state laws.

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) based on CERCLA at five sites, and claims have been asserted at 18 other sites. 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 $43.0 million as of December 31, 2006 and $42.5 million as of December 31, 2005, $14.4 million and $23.6 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 ongoing settlement discussions. 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 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.

Other

In addition, at times we become a party to other claims, lawsuits, arbitration proceedings and administrative procedures in the ordinary course of business. Management believes 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.

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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, 2006.

Executive Officers of the Company

Set forth below are the names, ages as of February 16, 2007 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	52	President and Chief Executive Officer, Director
Sharon D. Fiehler	50	Executive Vice President Human Resources and Administration
Richard A. Navarre	46	Chief Financial Officer and Executive Vice President of Corporate Development
Alexander C. Schoch	52	Executive Vice President Law and Chief Legal Officer
Roger B. Walcott, Jr.	50	Executive Vice President Strategy and Business Services
Richard M. Whiting	52	Executive Vice President and Chief Marketing Officer
Rick Bowen	51	President, Generation and Btu Conversion
Ian S. Craig	53	Managing Director Australia Operations
Jiri Nemec	50	Group Vice President U.S. Eastern Operations
Kemal Williamson	47	Group Vice President U.S. Western Operations

Gregory H. Boyce has been a director of the Company since March 2005. Mr. Boyce 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 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 Center for Energy and Economic Development, the National Mining Association and the National Coal Council, and a past board member of the Western Regional Council, Mountain States Employers Council and Wyoming Business Council.

Sharon D. Fiehler has been our Executive Vice President of Human Resources and Administration since April 2002, with executive responsibility for employee development, benefits, compensation, employee relations, affirmative action programs, information services, flight services and facilities management. She joined us in 1981 as Manager Salary Administration and has held a series of employee relations, compensation and salaried benefits positions. Ms. Fiehler holds degrees in social work and psychology and an MBA, and prior to joining Peabody 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 and a Board member of the Chancellor s Council of the University of Missouri at St. Louis. She is also a member of the Women s Advisory Council of the University of Missouri at St. Louis Executive Leadership Institute and the St. Louis Women s Forum.

Richard A. Navarre is our Chief Financial Officer and Executive Vice President of Corporate Development. He has served as Chief Financial Officer since October 1999. He also previously served as President of Peabody s COALSALES, LLC affiliate, President of Peabody Energy Solutions, Inc., Vice President of Finance and Vice President and Controller. He joined our predecessor company in 1993. Prior to joining us, Mr. Navarre was a senior manager with KPMG Peat Marwick. Mr. Navarre is former Chairman of the Bituminous Coal Operators Association. He serves on the Board of Advisors to the College of Business for Southern Illinois University at Carbondale and is a member of the International Business Advisory Board, University of Missouri-St. Louis, College of Business Administration. He is a member of Financial Executives International. Mr. Navarre is on the Board of Directors of the Missouri Historical Society.

Alexander C. Schoch was named our Executive Vice President Law 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 Strategy and Business Services in May 2006. Prior to that he was our Executive Vice President Resource Management and Strategic Planning since July 2005 and our Executive Vice President Corporate Development since February 2001. 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.

Richard M. Whiting became Executive Vice President and Chief Marketing Officer in May 2006. Prior to that he was our Executive Vice President Sales, Marketing and Trading since October 2002. Previously, Mr. Whiting served as our President and Chief Operating Officer and President of Peabody s COALSALES, LLC affiliate. He joined our predecessor company in 1976 and has held a number of operations, sales and engineering positions both at the corporate offices and at field locations. Mr. Whiting is the former Chairman of the National Mining Association s Safety and Health Committee, the former Chairman of the Bituminous Coal Operators Association, a past board member of the National Coal Council and is a member of the Visiting Committee of West Virginia University College of Engineering and Mineral Resources.

Rick Bowen became President of Generation and Btu Conversion in July 2006, 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. He joined us in September 2004 as Corporate Senior Vice President and President of Generation. Prior to joining us, Mr. Bowen served for 20 years with Dynegy Inc. and its predecessor companies. Mr. Bowen is a member of the Board of Directors of the Western Electric Coordinating Council and the Industry Advisory Board, Consortium for Electric Reliability Technology Solutions. He holds a Bachelor of Science in Business Administration and a Master of Business Administration from the University of Houston.

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.

Jiri Nemec has been our Group Vice President U.S. Eastern Operations since July 2005. Previously, Mr. Nemec was Group Executive of Appalachia and Highland Operations from April 2004 to July 2005; Appalachia Operations from January 2001 to April 2004; Midwest Operations from August 1999 to January 2001; and Northern Appalachia Operations from July 1998 to August 1999. He has extensive experience in mining engineering and operations, primarily with a Peabody subsidiary in West Virginia. He holds a Bachelor of Science Degree in Engineering from Pennsylvania State University and an MBA from Washington University.

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 an MBA from Kellogg Graduate School of Management, Northwestern University.

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 16, 2007, there were 952 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
2005		
First Quarter	$ 25.47	$ 18.38
Second Quarter	28.23	19.68
Third Quarter	43.03	26.01
Fourth Quarter	43.48	35.22
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

Dividend Policy

The quarterly dividend rate for Common Stock was increased 26% by the Board of Directors to $0.06 per share (from $0.0475 per share) on January 23, 2006, when a dividend of $0.06 per share was declared on Common Stock, payable on February 22, 2006, to stockholders of record on February 7, 2006. We paid quarterly dividends totaling $0.24 per share during the year ended December 31, 2006, and $0.17 per share during the year ended December 31, 2005. Most recently, our Board of Directors declared a dividend of $0.06 per share of Common Stock on January 23, 2007, payable on February 27, 2007, to stockholders of record on February 6, 2007. 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

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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.

Stock Split

On February 22, 2006, we effected a two-for-one stock split on all shares of our common stock. Shareholders of record at the close of business on February 7, 2006, received a dividend of one share of stock for every share held. The stock began trading ex-split on February 23, 2006. On March 30, 2005, we effected a two-for-one stock split on all shares of our common stock. Shareholders of record at the close of business on March 16, 2005 received a dividend of one share of stock for every share held. The stock began trading ex-split on March 31, 2005. All share and per share amounts in this Annual Report on Form 10-K reflect both two-for-one stock splits.

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, 2006, there were approximately 10.9 million shares available for repurchase. There were no share repurchases made in the three months ended December 31, 2006.

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Stock Performance Graph

The following performance graph compares the cumulative total return on our common stock with the cumulative total return of the following indices: (i) the S&P© 400 MidCap Stock Index; (ii) the S&P© 500 Stock Index; (iii) a peer group comprised of Arch Coal Inc., Massey Energy Company, CONSOL Energy, Inc. and Westmoreland Coal Company (Peer Group 1) and (iv) a peer group comprised of Arch Coal Inc., Massey Energy Company, CONSOL Energy, Inc., Foundation Coal Holdings Inc., Alpha Natural Resources, Inc. and International Coal Group, Inc. (Peer Group 2). The companies included in Peer Group 2 are listed in the Bloomberg U.S. Coal Index as of December 31, 2006. In November 2006, we were added to the S&P© 500 Stock Index and we have accordingly changed our equity market index to the S&P© 500 Stock Index from the S&P© 400 MidCap Stock Index. The graph assumes that the value of the investment in our common stock and each index was $100 at December 31, 2001. The graph also assumes that all dividends were reinvested and that investments were held through December 31, 2006. These indices are included for comparative purposes only and do not necessarily reflect management s opinion that such indices are an appropriate measure of the relative performance of the stock involved, and are not intended to forecast or be indicative of possible future performance of the common stock.

	Dec-01	Dec-02	Dec-03	Dec-04	Dec-05	Dec-06
Peabody Energy Corporation	$ 100	$ 105	$ 153	$ 299	$ 614	$ 605
S&P© 500 Stock Index	$ 100	$ 78	$ 100	$ 111	$ 117	$ 135
S&P© MidCap 400 Stock Index	$ 100	$ 85	$ 116	$ 135	$ 152	$ 168
Peer Group 1	$ 100	$ 71	$ 117	$ 175	$ 278	$ 229
Peer Group 2	$ 100	$ 70	$ 116	$ 173	$ 246	$ 197

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 2006 and 2005 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.

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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.

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 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 include 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, 2006, 2005, 2004, 2003 and 2002 from our audited financial statements. All share and per share amounts included in the following consolidated financial data have been retroactively adjusted to reflect the two-for-one stock splits, effective February 22, 2006, and March 30, 2005. 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.

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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,				
	2006	**2005**	**2004**	**2003**	**2002**
	(Dollars in thousands, except share and per share data)				
Results of Operations Data					
Revenues					
Sales	$ 5,144,925	$ 4,545,323	$ 3,545,027	$ 2,729,323	$ 2,630,371
Other revenues	111,390	99,130	86,555	85,973	89,267
Total revenues	5,256,315	4,644,453	3,631,582	2,815,296	2,719,638
Costs and expenses					
Operating costs and expenses	4,155,984	3,715,836	2,965,541	2,332,137	2,225,344
Depreciation, depletion and amortization	377,210	316,114	270,159	234,336	232,413
Asset retirement obligation expense	40,112	35,901	42,387	31,156	
Selling and administrative expenses	175,941	189,802	143,025	108,525	101,416
Other operating income:					
Net gain on disposal of assets	(132,162)	(101,487)	(23,829)	(32,772)	(15,763)
(Income) loss from equity affiliates	(23,852)	(30,096)	(12,399)	(2,872)	2,540
Operating profit	663,082	518,383	246,698	144,786	173,688
Interest expense	143,450	102,939	96,793	98,540	102,458
Early debt extinguishment costs	1,396		1,751	53,513	
Interest income	(12,726)	(10,641)	(4,917)	(4,086)	(7,574)
Income (loss) before income taxes and minority interests	530,962	426,085	153,071	(3,181)	78,804
Income tax provision (benefit)	(81,515)	960	(26,437)	(47,708)	(40,007)
Minority interests	11,780	2,472	1,282	3,035	13,292
Income from continuing operations	600,697	422,653	178,226	41,492	105,519
Loss from discontinued operations			(2,839)		
Income before accounting changes	600,697	422,653	175,387	41,492	105,519

Cumulative effect of accounting changes								(10,144)		
Net income	$	600,697	$	422,653	$	175,387	$	31,348	$	105,519
Basic earnings per share from continuing operations	$	2.28	$	1.62	$	0.72	$	0.19	$	0.51
Diluted earnings per share from continuing operations	$	2.23	$	1.58	$	0.70	$	0.19	$	0.49
Weighted average shares used in calculating basic earnings per share		263,419,344		261,519,424		248,732,744		213,638,084		208,662,940
Weighted average shares used in calculating diluted earnings per share		269,166,005		268,013,476		254,812,632		219,342,512		215,287,040
Dividends declared per share	$	0.24	$	0.17	$	0.13	$	0.11	$	0.10
Other Data										
Tons sold (in millions)		247.6		239.9		227.2		203.2		197.9
Net cash provided by (used in):										
Operating activities	$	595,726	$	702,759	$	283,760	$	188,861	$	234,804
Investing activities		(2,143,818)		(584,202)		(705,030)		(192,280)		(144,078)
Financing activities		1,371,325		(4,915)		693,404		48,598		(58,398)
Adjusted EBITDA[(1)]		1,080,404		870,398		559,244		410,278		406,101
Additions to property, plant, equipment & mine development		477,721		384,304		151,944		156,443		208,562
Federal coal lease expenditures		178,193		118,364		114,653				
Purchase of mining and related assets				141,195						
Acquisitions, net		1,552,313				429,061		90,000		46,012
Balance Sheet Data (at period end)										
Total assets	$	9,514,056	$	6,852,006	$	6,178,592	$	5,280,265	$	5,125,949
Total debt		3,263,826		1,405,506		1,424,965		1,196,539		1,029,211
Total stockholders equity		2,338,526		2,178,467		1,724,592		1,132,057		1,081,138

(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

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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,				
	2006	2005	2004	2003	2002
	(Dollars in thousands)				
Income from continuing operations	$ 600,697	$ 422,653	$ 178,226	$ 41,492	$ 105,519
Income tax provision (benefit)	(81,515)	960	(26,437)	(47,708)	(40,007)
Depreciation, depletion and amortization	377,210	316,114	270,159	234,336	232,413
Asset retirement obligation expense	40,112	35,901	42,387	31,156	
Interest expense	143,450	102,939	96,793	98,540	102,458
Early debt extinguishment costs	1,396		1,751	53,513	
Interest income	(12,726)	(10,641)	(4,917)	(4,086)	(7,574)
Minority interests	11,780	2,472	1,282	3,035	13,292
Adjusted EBITDA	$ 1,080,404	$ 870,398	$ 559,244	$ 410,278	$ 406,101

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 40 coal operations located throughout all major U.S. coal producing regions and internationally in Australia and Venezuela. In 2006, we sold 247.6 million tons of coal, which was approximately 38% greater than the sales of our closest competitor. Our domestic sales represented 22% of all U.S. coal sales and was approximately 80% greater than the sales of our closest domestic competitor. Based on Energy Information Administration (EIA) estimates, demand for coal in the United States was approximately 1.1 billion tons in 2006. Domestic coal consumption is expected to grow at an average rate of 1.8% per year through 2030 when U.S. coal demand is forecasted to be 1.8 billion tons. The EIA expects demand for coal use at coal-to-liquids (CTL) plants to grow to 112 million tons by 2030. Coal-fueled generation is used in most cases to meet baseload electricity requirements, and coal use generally grows at the approximate rate of electricity growth, which is expected to average 1.5% annually through 2030. Coal production located west of the Mississippi River is projected to provide most of the incremental growth as Western production increases to an estimated 68% share of total production in 2030. In 2005, coal s share of electricity generation was approximately 50%, a share that the EIA projects will grow to 57% by 2030.

Our primary customers are U.S. utilities, which accounted for 87% of our sales in 2006. We typically sell coal to utility customers under long-term contracts (those with terms longer than one year). During 2006, approximately 90% of our sales were under long-term contracts. As of December 31, 2006, production totaled 226.2 million tons and sales totaled 247.6 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.

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 Appalachia and Midwest operations. The principal business of the Western U.S. Mining segment is the mining, preparation and sale of steam coal, sold primarily to electric utilities. The principal business of the Eastern U.S. Mining segment is the mining, preparation and sale of steam coal, sold primarily to electric utilities, as well as the mining of metallurgical coal, sold to steel and coke producers.

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 predominantly 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 US$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 more than 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 2006, the Paso Diablo Mine contributed $28.0 million to segment Adjusted EBITDA in Corporate and Other Adjusted EBITDA and paid a dividend of $18.2 million. At December 31, 2006, our investment in Paso Diablo was $60.1 million.

Metallurgical coal is produced primarily from four of our Australian mines (two of which were acquired in the Excel transaction) and two of our U.S. mines. Metallurgical coal is approximately 5% of our total sales volume and approximately 3% of U.S. sales volume.

In addition to our mining operations, which comprised 87% of revenues in 2006, our trading and brokerage operations (13% of revenues), transactions utilizing our vast natural resource position (selling non-core land holdings and mineral interests) and other ventures generate revenues and additional cash flows.

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. The projects we are currently pursuing include the 1,600-megawatt Prairie State Energy Campus in Washington County, Illinois and 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. In October 2006, we entered an agreement with CMS Enterprises to share equally an expected 30% equity interest in the Prairie State Energy Campus and to oversee development and operation of the generating plant and coal mine. In the third quarter of 2006, the Prairie State Energy Campus received affirmation of the air quality permit from the U.S. Environmental Protection Agency, and in the fourth quarter of 2006, parties that had previously challenged the permit filed a new appeal.

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 generation of electricity. We are exploring several Btu conversion projects, which are designed to

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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.

Effective February 22, 2006, we implemented a two-for-one stock split on all shares of our common stock. All share and per share amounts in this annual report on Form 10-K reflect this split. 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.

Results of 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 primarily as a measure of our segments operating performance. 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 25 to our consolidated financial statements.

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 13.2% increase in revenues to $5.26 billion compared to 2005. Segment Adjusted EBITDA increased 13.8% to $1.23 billion primarily on growth in international volumes and higher sales prices from our Australian mining operations and increased results 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, equipment and third-party supply 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 year 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	54.7	52.5	2.2	4.2%
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	247.6	239.9	7.7	3.2%

Revenues

The following table presents revenues for the year ended December 31, 2006 and 2005:

	Year Ended December 31,		Increase to Revenues	
	2006	2005	$	%
	(Dollars in thousands)			
Sales	$ 5,144,925	$ 4,545,323	$ 599,602	13.2%
Other revenues	111,390	99,130	12,260	12.4%
Total revenues	$ 5,256,315	$ 4,644,453	$ 611,862	13.2%

In 2006, our total revenues were $5.26 billion, an increase of $611.9 million, or 13.2%, 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 regional sales due to late 2005 mine closures in the Western U.S. Mining operations and lower brokerage volumes.

Sales increased $599.6 million, or 13.2%, to $5.14 billion in 2006, which included increases of $91.9 million in Western U.S. Mining sales, $318.1 million in Eastern U.S. Mining sales and $245.1 million in Australian Mining sales, partially offset by a decrease of $55.5 million in our brokerage operations. 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. Offsetting this increase 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. On average, per ton sales prices in our Eastern U.S. Mining operations increased, driven by increases in metallurgical and steam coal prices. Sales volumes increased due to a newly developed mine, which began operation in late 2005, and the expansion of several existing mines, partially offset by lower production at one of our mines and at contract miner operations, as both managed geologic, equipment and, in certain locations, supplier issues. Sales 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 sales decreased $55.5 million in 2006 compared to prior year due to lower sales volumes, partially offset by higher sales prices.

Other revenues increased $12.3 million, or 12.4%, compared to prior year. The increase includes proceeds of $28.2 million from settlement of commitments by a third-party coal producer following a brokerage contract restructuring. Offsetting this increase were lower revenues related to synthetic fuel facilities as customers idled their synthetic fuel plants due to high crude oil prices.

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Segment Adjusted EBITDA

Our total segment Adjusted EBITDA was $1.23 billion for the year ended 2006, compared with $1.08 billion in the prior year. Details were as follows:

	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	384,107	374,628	9,479	2.5%
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	$ 1,228,196	$ 1,079,307	$ 148,889	13.8%

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 by the cessation of operations at the Black Mesa mine in late 2005.

Eastern U.S. Mining operations Adjusted EBITDA increased $9.5 million, or 2.5%, compared to prior year primarily due to higher sales volumes partially offset by a decrease in margin per ton. Results improved compared to prior year as benefits of higher volumes, product mix and sales prices were partially offset by higher costs. The Eastern U.S. Mining operations experienced higher costs per ton due to fuel costs, revenue-based royalties and production taxes as well as higher costs associated with equipment, geologic and contract miner 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. Also impacting Eastern U.S. Mining results was $8.9 million of income from a settlement related to customer billings regarding coal quality.

Our Australian Mining operations Adjusted EBITDA increased $75.8 million, or 37.4%, compared to prior year 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 the prior year, as 2006 results included proceeds from restructuring the brokerage contract mentioned above, improved brokerage margins and contribution from the newly established international operation, partially offset by lower domestic trading results.

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Income Before Income Taxes and Minority Interests

The following table presents income before income taxes and minority interests for the years ended December 31, 2006 and 2005:

	Year Ended December 31,		Increase (Decrease) to Income	
	2006	2005	$	%
	(Dollars in thousands)			
Total Segment Adjusted EBITDA	$ 1,228,196	$ 1,079,307	$ 148,889	13.8%
Corporate and Other Adjusted EBITDA	(147,792)	(208,909)	61,117	29.3%
Depreciation, depletion and amortization	(377,210)	(316,114)	(61,096)	(19.3)%
Asset retirement obligation expense	(40,112)	(35,901)	(4,211)	(11.7)%
Interest expense and early debt extinguishment costs	(144,846)	(102,939)	(41,907)	(40.7)%
Interest income	12,726	10,641	2,085	19.6%
Income before income taxes and minority interests	$ 530,962	$ 426,085	$ 104,877	24.6%

Income before income taxes and minority interests of $531.0 million for 2006 is $104.9 million, or 24.6%, 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 $61.1 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 $30.7 million. The 2006 activity included sales with a combined gain of $66.3 million from the sale of non-strategic coal reserves and surface lands located in Kentucky and West Virginia, 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 $26.7 million. In comparison, activity in 2005 included a $37.4 million gain on exchange of coal reserves as part of a dispute settlement with a third-party supplier, a $31.1 million gain from 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, a $6.2 million gain on an asset exchange from which we received Illinois Basin coal and other gains on asset disposals of $14.3 million;

Lower selling and administrative expenses of $13.9 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 the prior year;

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; 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.

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Depreciation, depletion and amortization increased $61.1 million in 2006 due to higher production volume, acquisitions and the impact of escalating 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 $41.9 million primarily due to approximately $1.7 billion in new debt issuances in the second half of 2006 to finance the Excel acquisition. See Liquidity and Capital Resources for more details of the debt issued.

Net Income

The following table presents net income for the year ended December 31, 2006 and 2005:

	Year Ended December 31,		Increase (Decrease) to Income	
	2006	2005	$	%
	(Dollars in thousands)			
Income before income taxes and minority interests	$ 530,962	$ 426,085	$ 104,877	24.6%
Income tax benefit (provision)	81,515	(960)	82,475	n/a
Minority interests	(11,780)	(2,472)	(9,308)	(376.5)%
Net income	$ 600,697	$ 422,653	$ 178,044	42.1%

Net income increased $178.0 million in 2006 compared to prior year due to the increase in income 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.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Summary

Our 2005 revenues of $4.64 billion increased 27.9% over the prior year. Revenues were driven higher by improved pricing in all of our mining operations and increased sales volume with 239.9 million tons sold compared to 227.2 million tons in 2004. Segment Adjusted EBITDA of $1.08 billion was a 39.5% increase over the prior year due to increases in sales volumes and prices at our U.S. and Australian Mining Operations. Results in our Western U.S. Mining Operations segment include amounts for our April 15, 2004, acquisition of the Twentymile Mine in Colorado. Results in our Australian Mining Operations segment include amounts for our April 15, 2004, acquisition of the Burton and North Goonyella Mines as well as the opening of the Eaglefield Mine adjacent to the North Goonyella Mine in the fourth quarter of 2004. Our Corporate and Other segment includes results from our December 2004 acquisition of a 25.5% interest in Carbones del Guasare, which owns and operates the Paso Diablo Mine in Venezuela. In addition, higher gains on property transactions contributed to higher year over year results. Net income was $422.7 million in 2005, or $1.58 per diluted share, an increase of 141.0% over 2004 net income of $175.4 million, or $0.69 per diluted share.

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Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2005 and 2004:

	Year Ended December 31,		Increase (Decrease)	
	2005	2004	Tons	%
	(Tons in millions)			
Western U.S. Mining Operations	154.3	142.2	12.1	8.5%
Eastern U.S. Mining Operations	52.5	51.7	0.8	1.5%
Australian Mining Operations	8.3	6.1	2.2	36.1%
Trading and Brokerage Operations	24.8	27.2	(2.4)	(8.8)%
Total tons sold	239.9	227.2	12.7	5.6%

Revenues

The table below presents revenues for the years ended December 31, 2005 and 2004:

	Year Ended December 31,		Increase to Revenues	
	2005	2004	$	%
	(Dollars in thousands)			
Sales	$ 4,545,323	$ 3,545,027	$ 1,000,296	28.2%
Other revenues	99,130	86,555	12,575	14.5%
Total revenues	$ 4,644,453	$ 3,631,582	$ 1,012,871	27.9%

Our revenues increased by $1.01 billion, or 27.9%, to $4.64 billion compared to prior year. The three mines we acquired in the second quarter of 2004 contributed $365.2 million of revenue growth due to the additional 105 days of operations in 2005 compared to the prior year. The remaining $647.7 million of revenue growth was driven by higher sales prices and volumes across all mining segments and improved volumes in our brokerage operations.

Sales increased 28.2% to $4.55 billion in 2005, reflecting increases in every operating segment. Western U.S. Mining sales increased $222.2 million, Eastern U.S. Mining sales were $224.0 million higher, sales in Australia Mining improved $328.0 million and sales from our brokerage operations increased $226.0 million. Sales in every segment increased on improved pricing, and volumes were higher in every segment other than Trading and Brokerage. Our average sales price per ton increased 17.4% during 2005 due to increased demand for all of our coal products, which drove pricing higher, particularly in the regions where we produce metallurgical coal. Prices for metallurgical coal and our ultra-low sulfur Powder River Basin coal have been the subject of increasing demand. We sell metallurgical coal from our Eastern U.S. and Australian Mining operations. We sell ultra-low sulfur Powder River Basin coal from our Western U.S. Mining operations. The sales mix also improved due to an increase in sales from our Australian Mining segment, where per ton prices are higher than in domestic markets due primarily to a higher proportion of metallurgical coal production in the Australian segment sales mix.

The increase in Eastern U.S. Mining operations sales was primarily due to improved pricing for both steam and metallurgical coal from the region. On average, prices in our Eastern U.S. Mining operations increased 14.1% to $33.10 per ton. Sales increased in our Western U.S. Mining operations due to higher demand-driven volumes and prices, particularly in the Powder River Basin. Overall, prices in our Western U.S. Mining operations increased 6.6% to $10.45 per ton. Powder River Basin production and sales volumes were up as a result of increasingly strong demand for the mines low-sulfur product, which continues to expand its market area geographically. Powder River Basin operations were able to ship record volumes during 2005 by overcoming train derailments, weather and track maintenance disruptions on the main shipping line out of the basin. Our Twentymile Mine, acquired in April of 2004, contributed to higher sales in 2005 due to an additional four months of ownership, higher prices and increased mine productivity. Sales from our Australian Mining operations were $328.0 million, or 122.1%, higher than in 2004. The increase in Australian sales was due primarily to a 63.3% increase in per ton sales prices largely due to higher international metallurgical coal prices, an increase in volumes which included the opening of our Eaglefield surface mine at the end of 2004, and $197.6 million of incremental sales from the two mines we acquired in April 2004 due to 105 additional days of operations in 2005 compared to 2004. Our Trading and Brokerage operations sales increased $226.0 million in 2005 compared to prior year due to an increase in average per ton prices and higher eastern U.S. and international brokerage volumes.

Other revenues increased $12.6 million, or 14.5%, compared to prior year primarily due to proceeds from a purchase contract restructuring and higher synthetic fuel revenues in the Midwest.

Segment Adjusted EBITDA

Our total segment Adjusted EBITDA of $1.08 billion for 2005 was $305.5 million higher than 2004 segment Adjusted EBITDA of $773.8 million, and was composed of the following:

	Year Ended December 31,		Increase to Segment Adjusted EBITDA	
	2005	2004	$	%
	(Dollars in thousands)			
Western U.S. Mining Operations	$ 459,039	$ 402,052	$ 56,987	14.2%
Eastern U.S. Mining Operations	374,628	280,357	94,271	33.6%
Australian Mining Operations	202,582	50,372	152,210	302.2%
Trading and Brokerage Operations	43,058	41,039	2,019	4.9%
Total Segment Adjusted EBITDA	$ 1,079,307	$ 773,820	$ 305,487	39.5%

Adjusted EBITDA from our Western U.S. Mining operations increased $57.0 million during 2005 due to a margin per ton increase of $0.15, or 5.3%, and a sales volume increase of 12.1 million tons. Results in the Powder River Basin operations contributed to the increase in Western U.S. Mining operations as it earned 12.3% higher per ton margins while increasing volumes 8.5% in response to greater demand for our low-sulfur products. Improved revenues overcame increased unit costs that resulted from higher fuel and explosives costs, lower than anticipated volume due to rail difficulties and an increase in revenue-based royalties and production taxes. The Twentymile Mine, acquired in April of 2004, contributed $25.4 million more to Adjusted EBITDA in 2005 than in 2004, due to four months of incremental ownership and a 22.2% increase in per ton margin.

Eastern U.S. Mining operations Adjusted EBITDA increased $94.3 million, or 33.6%, compared to prior year primarily due to an increase in margin per ton of $1.71, or 31.5%. Our Eastern U.S. Mining operations Adjusted EBITDA increased as a result of sales price increases, partially offset by lower production at two of our mines and higher costs related to geologic issues, contract mining, fuel, repair and maintenance and the impact of heavy rainfall on surface operations early in the year.

Our Australian Mining operations Adjusted EBITDA increased $152.2 million in the current year, a 302.2% increase compared to prior year due to an increase of $16.23, or 197.4%, in margin per ton and 2.2 million additional tons shipped. Our Australian operations produce mostly (75% to 85%) high margin metallurgical coal. The two mines we acquired in April 2004 added $87.4 million to Adjusted EBITDA compared to eight months of ownership in 2004. The remaining increase of $64.8 million was primarily due to an increase in volume, including tonnage from our surface operation opened at the end of the prior year, and an increase of 63.3% in average per ton sale price. While current year margins benefited from strong sales prices, margin growth was limited by the impact of port congestion, related demurrage costs and higher costs due to geological problems at the underground mine.

Trading and Brokerage operations Adjusted EBITDA increased $2.0 million from the prior year primarily due to higher brokerage results. Results in 2005 included a net charge of $4.0 million, primarily related to the breach of a coal supply contract by a producer.

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Reconciliation of Segment Adjusted EBITDA to Income Before Income Taxes and Minority Interests

	Year Ended December 31,		Increase (Decrease) to Income	
	2005	2004	$	%
	(Dollars in thousands)			
Total Segment Adjusted EBITDA	$ 1,079,307	$ 773,820	$ 305,487	39.5%
Corporate and Other Adjusted EBITDA	(208,909)	(214,576)	5,667	2.6%
Depreciation, depletion and amortization	(316,114)	(270,159)	(45,955)	(17.0)%
Asset retirement obligation expense	(35,901)	(42,387)	6,486	15.3%
Interest expense and early debt extinguishment costs	(102,939)	(98,544)	(4,395)	(4.5)%
Interest income	10,641	4,917	5,724	116.4%
Income before income taxes and minority interests	$ 426,085	$ 153,071	$ 273,014	178.4%

Income before income taxes and minority interest of $426.1 million for the current year is $273.0 million, or 178.4%, higher than prior year primarily due to improved segment Adjusted EBITDA as discussed above. Increases in depreciation, depletion and amortization expense and interest expense offset improvements in Corporate and Other Adjusted EBITDA, asset retirement obligation expense, debt extinguishment costs and interest income.

Corporate and Other Adjusted EBITDA results include selling and administrative expenses, equity income from our Venezuelan 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 and resource management. The $5.7 million improvement in Corporate and Other Adjusted EBITDA (net expense) in 2005 compared to 2004 included:

net gains on asset sales that were $77.7 million higher than prior year primarily due to a $37.4 million gain from a property exchange related to settlement of a contract dispute with a third-party coal supplier (see Note 3 to our consolidated financial statements), sales of Penn Virginia Resource Partners, L.P. (PVR) units ($31.1 million) (see Note 9 to our consolidated financial statements), resource sales involving non-strategic coal assets and properties ($12.5 million), and an asset exchange in which we acquired Illinois Basin coal reserves ($6.2 million). The gain from PVR unit sales in 2005 was from the sale of all of our remaining 0.838 million units compared to a gain of $15.8 million on the sale of 0.775 million units in two separate transactions during 2004. All other gains on asset disposals in 2005 and 2004 were $14.3 million and $8.0 million, respectively;

higher equity income of $18.7 million from our 25.5% interest in Carbones del Guasare (acquired in December 2004), which owns and operates the Paso Diablo Mine in Venezuela, and;

lower net expenses related to generation development of $5.1 million, primarily due to reimbursements from the Prairie State Energy Campus partnership group.

These improvements were partially offset by:

a $36.0 million increase in past mining obligations expense, primarily related to higher retiree health care costs. The increase in retiree health care costs was actuarially driven by higher trend rates, and lower interest discount assumptions and higher amortization of actuarial losses in 2005, and;

an increase of $46.8 million in selling and administrative expenses primarily related to accruals for higher short-term and long-term performance-based incentive plans ($32.2 million). These incentives are principally long-term plans that are driven by total shareholder returns. Our share price increased 104% during 2005, significantly outperforming industrial benchmarks and our coal peer group average. The remaining increase in selling and administrative expenses was due to higher personnel and outside services costs needed to advance our growth initiatives in areas such as China and BTU conversion, acquisitions and regulatory costs (e.g. Sarbanes-Oxley), and an increase in advertising costs related to an industry awareness campaign launched in late 2005.

Depreciation, depletion and amortization increased $46.0 million during 2005. Approximately 56% of the increase was due to acquisitions completed during 2004 and the remainder was from increased volumes at existing mines and operations opened during 2005. Asset retirement obligation expense decreased $6.5 million in 2005 due to additional expenses incurred in 2004 to accelerate the planned reclamation of certain closed mine sites. Interest expense increased $6.1 million primarily related to a full year of interest in 2005 on $250 million of 5.875% Senior Notes issued in late March of 2004 and increases in the cost of floating rate debt due to higher interest rates. Interest income improved $5.7 million due to higher yields on short-term interest rates and an increase in invested balances due to improved cash flows during 2005.

Net Income

	Year Ended December 31,		Increase (Decrease) to Income	
	2005	2004	$	%
	(Dollars in thousands)			
Income before income taxes and minority interests	$ 426,085	$ 153,071	$ 273,014	178.4%
Income tax benefit (provision)	(960)	26,437	(27,397)	(103.6)%
Minority interests	(2,472)	(1,282)	(1,190)	(92.8)%
Income from continuing operations	422,653	178,226	244,427	(137.1)%
Loss from discontinued operations		(2,839)	2,839	n/a
Net income	$ 422,653	$ 175,387	$ 247,266	141.0%

Net income increased $247.3 million, or 141.0%, compared to the prior year due to the increase in income before income taxes and minority interests discussed above, partially offset by increases in our income tax provision. The income tax benefit in 2004 included a $25.9 million reduction in the valuation allowance on net operating loss carry-forwards and alternative minimum tax credits. The income tax provision in 2005 was higher based on the increase in pretax income which was partially offset by the higher permanent benefit of percentage depletion and the partial benefit of tax loss from a deemed liquidation of a subsidiary arising as an indirect consequence of a comprehensive and strategic internal restructuring we completed during 2005. This restructuring resulted from efforts to better align corporate ownership of subsidiaries on a geographic and functional basis.

Outlook

Events Impacting Near-Term Operations

In October 2006, we acquired Excel Coal Limited, which included three operating mines, two late development-stage mines and a development-stage mine. These development-stage mines are expected to begin shipments in 2007, and our 2007 results will be impacted to the extent we complete ramp up activities at these development-stage mines on time and at expected capacity. Furthermore, our two primary Australian shipping points, Dalrymple Bay Coal Terminal and Port of Newcastle, are experiencing significant queues of vessels, which could result in delayed shipments and demurrage charges.

Currently depressed Central Appalachian coal prices combined with escalating costs of our third-party contractors could adversely impact our saleable production as it becomes uneconomic to mine.

Although we expect that the Twentymile longwall system will allow for expanded capacity over the next several years, we continue to manage equipment and lower coal quality issues at our Twentymile mine.

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Shipments from our Powder River Basin mines improved in 2006, but were still impacted by rail service disruptions. Rail carriers are expected to continue improvements in 2007. Although we currently expect to increase our shipment levels from our Powder River Basin operations in 2007 compared with 2006, our ability to reach these targeted shipment levels is dependent upon the performance of the rail carriers.

Our union workforce east of the Mississippi River is primarily represented by the UMWA. The UMWA-represented workers at one of our eastern mines operate under a contract that expires on December 31, 2007. The remainder of our UMWA-represented workers in the east operate under a recently signed, five-year labor agreement expiring December 31, 2011. The new contract mirrors the 2007 National Bituminous Coal Wage Agreement and stipulates a $1.50 per hour increase to wages effective January 1, 2007 and a total wage increase of $4.00 per hour over the life of the agreement. The contract also calls for a $1,000 bonus for each of our UMWA-represented employees.

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. Approximately 115 gigawatts of new coal-fueled electricity generating capacity is scheduled to come on line around the world over the next three years, and the EIA projects an additional 156 gigawatts of new U.S. coal-fueled generation by 2030, which by itself represents more than 500 million tons of additional coal demand.

Global coal markets continued to grow, driven by increased demand from growing economies. The U.S. economy grew at an annual rate of 3.5% based on fourth quarter 2006 data as reported by the U.S. Commerce Department, while China s economy grew 10.7% in 2006 as published by the National Bureau of Statistics of China. Metallurgical coal continued to sell at a significant premium to steam coal. Metallurgical markets, while off record levels, remain strong as seaborne metallurgical coal prices for the upcoming fiscal year were settling from a reference price near $100 per metric ton and as China steel production shows signs of continued growth over 2005 levels. We expect to capitalize on the strong global market for metallurgical coal primarily through production and sales of metallurgical coal from our Appalachia and Australian operations. In response to growing international markets, we established an international trading group in 2006, and added another operations office in Europe in early 2007.

Coal-to-gas 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 coal-to-liquids, and in the U.S. coal-to-liquid technologies are receiving growing bipartisan support as demonstrated by the newly introduced CTL bills such as the Coal-to-Liquid Fuel Promotion Act within the Senate. China and India are developing coal-to-gas and coal-to-liquids 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 3.5 billion tons of proven and probable reserves in the Southern Powder River Basin, and we sold 138.4 million tons of coal from this region during 2006, an increase of 10.1% over the prior year.

We are targeting 2007 production of 240 to 260 million tons and total sales volume of 265 to 285 tons, including 15 to 18 million tons of metallurgical coal. As of December 31, 2006, our unpriced 2007 volumes for planned produced tonnage were 5 to 15 million U.S. tons and 14 million Australia tons. Our total unpriced planned production for 2008 is approximately 70 to 80 million tons in the United States and 20 to 22 million tons in Australia.

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.

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, workers compensation obligations and defined benefit pension plans. Detailed information related to these liabilities is included in Notes 14, 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 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, 2006, for these liabilities totaled $178.7 million, while payments were $146.2 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.

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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]	$ 9,501	$ (7,989)
Effect on total postretirement benefit obligation[1]	$ 179,264	$ (150,765)

Discount rate:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in thousands)	
Effect on total service and interest cost components[1]	$ 1,064	$ (1,496)
Effect on total postretirement benefit obligation[1]	$ (78,243)	$ 82,702

(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 8.47 years at December 31, 2006.

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, 2006, was $40.1 million, and payments totaled $36.6 million. See detailed information regarding our asset retirement obligations in Note 13 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 basis of recorded assets and liabilities. SFAS No. 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In 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 11.

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. This interpretation is effective for fiscal years beginning after December 15, 2006 (January 1, 2007 for the Company).

Revenue Recognition

In general, we recognize revenues when they are realizable and earned. We generated 98% of our revenue in 2006 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 in over-the-counter markets. 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 and emission allowance positions. 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.

All of the contracts in our trading portfolio as of December 31, 2006 were valued utilizing prices from over-the-counter market sources, adjusted for coal quality and traded transportation differentials. As of December 31, 2006, 41% of the estimated future value of our trading portfolio was scheduled to be realized by the end of 2007 and 80% within 24 months. See Note 5 to our consolidated financial statements for additional details regarding assets and liabilities from our coal trading activities.

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 the sale 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 was $595.7 million for the year ended December 31, 2006, a decrease of $107.1 million compared to $702.8 million provided by operating activities in the prior year. The decrease was primarily related to the timing of working capital needs. The decrease in cash from operating activities would have been $30.4 million lower had 2006 and 2005 operating cash flows been shown on a comparable basis. The 2006 operating cash flows include a required reclassification of the excess tax benefit related to stock option exercises ($33.2 million) from operating to financing activities.

Net cash used in investing activities was $2.14 billion for the year ended December 31, 2006 compared to $584.2 million used in the prior year. The increase reflects the acquisition of Excel for $1.51 billion, net of cash acquired, higher capital expenditures of $93.4 million, higher federal coal lease expenditures of $59.8 million, the acquisition of an additional interest in a joint venture for $44.5 million, and the receipt of notes in lieu of payments on asset sales of $45.6 million, partially offset by higher proceeds from asset disposals of $46.9 million in 2006 and the purchase of mining and related assets of $141.2 million in 2005. Capital expenditures included longwall equipment and mine development at our Australian mines (including our recently acquired Excel operations), the opening of new mines and the purchase of equipment for expansion. The $141.2 million purchase of mining and related assets in 2005 included 70 million tons of Illinois and Indiana coal reserves, surface properties and equipment from Lexington Coal Company ($56.5 million) and rail, loadout and surface facilities as well as other mining assets for $84.7 million from another major coal producer.

Net cash provided by financing activities was $1.37 billion during the year ended December 31, 2006, compared to a use of $4.9 million in 2005. In 2006, we issued net borrowings of $1.74 billion, which were 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. See the detailed discussion of our Senior Unsecured Credit Facility, Convertible Junior Subordinated Debentures, Senior Notes offerings and borrowings under our Senior Unsecured Credit Facility below. In addition to the net issuance of debt related to the Excel acquisition, we repaid $23.8 million of debt held by a majority-owned joint venture, purchased $7.7 million of our 5.875% Senior Notes in the open market, and made scheduled debt repayments of $11.1 million on our 5% Subordinated Note and other notes payable.

The 2006 activity compared to 2005 also reflected payments for common stock repurchases of $99.8 million, debt issuance costs of $40.6 million and higher dividends of $18.9 million. During the year ended December 31, 2006, we repurchased 2.2 million of our common shares at a cost of $99.8 million under our share repurchase program as authorized by the Board of Directors. The 2006 activity included a decrease in the usage of our accounts receivable securitization program of $5.8 million compared to an increase of $25.0 million in 2005. The 2006 activity compared to 2005 also reflected $7.0 million lower proceeds from the exercise of stock options as well as a $33.2 million tax benefit related to stock option exercises included in financing activity based on the newly adopted accounting standard for share-based compensation (see Newly Adopted Accounting Pronouncements below for more discussion about the adoption of this standard). In 2005, the tax benefit related to stock option exercises (totaling $30.4 million) was included in operating activities.

Our total indebtedness as of December 31, 2006 and 2005 consisted of the following:

	December 31,	
	2006	2005
	(Dollars in thousands)	
Term Loan under Senior Unsecured Credit Facility	$ 547,000	$
Term Loan under Senior Secured Credit Facility		442,500
Convertible Junior Subordinated Debentures due 2066	732,500	
7.375% Senior Notes due 2016	650,000	
6.875% Senior Notes due 2013	650,000	650,000
7.875% Senior Notes due 2026	246,897	
5.875% Senior Notes due 2016	231,845	239,525
5.0% Subordinated Note	59,504	66,693
6.84% Series C Bonds due 2016	43,000	
6.34% Series B Bonds due 2014	21,000	
6.84% Series A Bonds due 2014	10,000	
Capital lease obligations	56,707	1,529
Fair value of interest rate swaps	(13,784)	(8,879)
Other	29,157	14,138
Total	$ 3,263,826	$ 1,405,506

Senior Unsecured Credit Facility

In September 2006, we entered into a Third Amended and Restated Credit Agreement, which established a $2.75 billion Senior Unsecured Credit Facility and which amended and restated in full our then existing $1.35 billion Senior Secured Credit Facility. The Senior Unsecured Credit Facility provides a $1.8 billion Revolving Credit Facility and a $950.0 million Term Loan Facility. The Revolving Credit Facility replaced our previous $900.0 million revolving credit facility and the increased capacity is intended to accommodate working capital needs, letters of credit, the funding of capital expenditures and other general corporate purposes. The Revolving Credit Facility also includes a $50.0 million sub-facility available for same-day swingline loan borrowings. In September 2006, we borrowed $312.0 million under the Revolver in conjunction with the Excel acquisition and repaid this $312.0 million outstanding balance in December 2006 with net proceeds from the Debentures.

The Term Loan Facility consisted of an unsecured $440.0 million portion, which was drawn at closing to replace the previous term loan ($437.5 million balance at time of replacement; $442.5 million at December 31, 2005) issued under the Senior Secured Credit Facility. The Term Loan Facility also included a Delayed Draw Term Loan Sub-Facility of up to $510.0 million, which was fully drawn in October 2006 in connection with the Excel acquisition. In December 2006, $403.0 million of the outstanding balance of the Term Loan Facility ($950.0 million was outstanding at time of repayment) was repaid with the net proceeds from the Debentures. In conjunction with the establishment of the Senior Unsecured Credit Facility, we incurred $8.6 million in financing costs, of which $5.6 million related to the Revolving Credit Facility and $3.0 million related to the Term Loan Facility. These debt issuance costs will be amortized to interest expense over five years, the term of the Senior Unsecured Credit Facility.

Loans under the facility are available in U.S. dollars, with a sub-facility under the Revolving Credit Facility available in Australian dollars, pounds sterling and Euros. Letters of credit under the Revolving Credit Facility are available to us in U.S. dollars with a sub-facility available in Australian dollars, pounds sterling and Euros. The interest rate payable on the Revolving Credit Facility and the Term Loan Facility under the Senior Unsecured Credit Facility is LIBOR plus 1.0% with step-downs to LIBOR plus 0.50% based on improvement in the leverage ratio, as defined in the Third Amended and Restated Credit Agreement. The rate applicable to the Term Loan Facility was 6.35% at December 31, 2006.

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

As of December 31, 2006, we had no borrowings outstanding under our Revolving Credit Facility. Our revolving line of credit was primarily used for standby letters of credit until September 2006, when we also used the revolving line of credit to facilitate the Excel acquisition. As discussed above, the $312.0 million outstanding under the revolving line of credit was repaid in December 2006 with net proceeds from the Debentures. The remaining available borrowing capacity ($1.29 billion as of December 31, 2006) will be used to fund strategic acquisitions or meet other financing needs, including standby letters of credit. During 2005, we had no borrowings outstanding under our previous $900.0 million revolving line of credit, which we used primarily for standby letters of credit. We were in compliance with all of the covenants of the Senior Unsecured Credit Facility, the 6.875% Senior Notes, the 5.875% Senior Notes, the 7.375% Senior Notes, the 7.875% Senior Notes, and the Convertible Junior Subordinated Debentures as of December 31, 2006.

Convertible Junior Subordinated Debentures

On December 20, 2006, we issued $732.5 million aggregate principal amount of 4.75% Convertible Junior Subordinated Debentures due 2066 (the Debentures), including $57.5 million issued pursuant to the underwriters exercise of their over-allotment option. Net proceeds from the offering, after deducting underwriting discounts and offering expenses, were $715.0 million and were used to repay indebtedness under our Senior Unsecured Credit Facility. The Debentures will pay interest semiannually at a rate of 4.75% per year. We may elect to, and if and to the extent that a mandatory trigger event (as defined in the indenture governing the Debentures) has occurred and is continuing will be required to, defer interest payments on the Debentures. After five years of deferral at our option, or upon the occurrence of a mandatory trigger event, we generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay deferred interest, subject to certain limitations. In no event may we defer payments of interest on the Debentures for more than ten years.

The Debentures are convertible at any time on or prior to December 15, 2036 if any of the following conditions occur: (i) our closing common stock price exceeds 140% of the then applicable conversion price for the Debentures (currently $86.73 per share) for at least 20 of the final 30 trading days in any quarter; (ii) a notice of redemption is issued with respect to the Debentures; (iii) a change of control, as defined in the indenture governing the Debentures; (iv) satisfaction of certain trading price conditions; and (v) other specified corporate transactions described in the indenture governing the Debentures. In addition, the Debentures are convertible at any time after December 15, 2036 to December 15, 2041, the scheduled maturity date. In the case of conversion following a notice of redemption or upon a non-stock change of control, as defined in the indenture governing the Debentures, holders may convert their Debentures into cash in the amount of the principal amount of their Debentures and shares of our common stock for any conversion value in excess of the principal amount. In all other conversion circumstances, holders will receive perpetual preferred stock (see Note 17 to our consolidated financial statements) with a liquidation preference equal to the principal amount of their Debentures, and any conversion value in excess of the principal amount will be settled with our common stock. The consideration delivered upon conversion will be based upon an initial conversion rate of 16.1421 shares of common stock per $1,000 principal amount of Debentures, subject to adjustment. This conversion rate represents an initial conversion price of approximately $61.95 per share, a 40% premium over the closing stock price of $44.25 on December 14, 2006, the date of the pricing of the offering of the Debentures.

The Debentures are unsecured obligations, ranking junior to all existing and future senior and subordinated debt (excluding trade accounts payable or accrued liabilities arising in the ordinary course of

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business) except for any future debt that ranks equal to or junior to the Debentures. The Debentures will rank equal in right of payment with our obligations to trade creditors. Substantially, all of our existing indebtedness is senior to the Debentures. In addition, the Debentures will be effectively subordinated to all indebtedness of our subsidiaries. The indenture governing the Debentures places no limitation on the amount of additional indebtedness that we or any of our subsidiaries may incur (see Note 12 of our consolidated financial statements for additional information on the Debentures).

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

On October 12, 2006, we completed a $650 million offering of 7.375% 10-year Senior Notes due 2016 and $250 million of 7.875% 20-year Senior Notes due 2026. The notes are general unsecured obligations and rank senior in right of payment to any subordinated indebtedness; equally in right of payment with any senior indebtedness; effectively junior in right of payment to our existing and future secured indebtedness, to the extent of the value of the collateral securing that indebtedness; and effectively junior to all the indebtedness and other liabilities of our subsidiaries that do not guarantee the notes. Interest payments are scheduled to occur on May 1 and November 1 of each year, commencing on May 1, 2007.

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

Series Bonds

As of December 31, 2006, we had $74.0 million in Series Bonds outstanding, which were assumed as part of the Excel acquisition. The 6.84% Series A Bonds have a balloon maturity in December 2014. The 6.34% Series B Bonds mature in December 2014 and are payable in installments beginning December 2008. The 6.84% Series C Bonds mature in December 2016 and are payable in installments beginning December 2012. Interest payments occur in June and December of each year.

Interest Rate Swaps

Prior to completion of the Senior Unsecured Credit Facility, we had two $400.0 million interest rate swaps. A $400.0 million notional amount floating-to-fixed interest rate swap was designated as a hedge of changes in expected cash flows on the previous term loan under the Senior Secured Credit Facility. Under this swap, we paid a fixed rate of 6.764% and received a floating rate of LIBOR plus 2.5% that reset each March 15, June 15, September 15 and December 15 based upon the three-month LIBOR rate. A $400.0 million notional amount fixed-to-floating interest rate swap was designated as a hedge of the changes in the fair value of the 6.875% Senior Notes due 2013. Under this swap, we paid a floating rate of LIBOR plus 1.97% that reset each March 15, June 15, September 15 and December 15 based upon the three-month LIBOR rate and received a fixed rate of 6.875%.

In conjunction with the completion of the new Senior Unsecured Credit Facility, the $400.0 million notional amount floating-to-fixed interest rate swap was terminated and resulted in payment to us of $5.2 million. We recorded the $5.2 million fair value of the swap in Accumulated other comprehensive loss on the consolidated balance sheet and will amortize this amount to interest expense over the remaining term of the forecasted interest payments initially hedged. We then entered into a $120.0 million notional amount floating-to-fixed interest rate swap with a fixed rate of 6.25% and a floating rate of LIBOR plus 1.0%. This interest rate swap was designated as a hedge of the variable interest payments on the Term Loan under the new Senior Unsecured Credit Facility.

We also terminated $280.0 million of our $400.0 million notional amount fixed-to-floating interest rate swap designated as a hedge of the changes in fair value of the 6.875% Senior Notes due 2013. Reducing the notional amount of the interest rate swap to $120.0 million resulted in payment of $5.2 million to the counterparty. Reduction of the notional amount of the swap did not affect our floating and fixed rates. The $5.2 million of fair value associated with the termination of the $280.0 million portion of the swap was recorded as an adjustment to the carrying value of long-term debt and will be amortized to interest expense through maturity of the 6.875% Senior Notes due 2013.

Because the critical terms of the swaps and the respective debt instruments they hedge coincide, there was no hedge ineffectiveness recognized in the consolidated statements of operations during the years ended December 31, 2006 and 2005. At December 31, 2006 there was an unrealized loss related to the cash flow hedge of $2.5 million and at December 31, 2005 there was an unrealized gain related to the cash flow hedge of $2.3 million. As of December 31, 2006 and 2005, the net unrealized loss on the fair value hedges discussed above were $13.8 million and $8.9 million, respectively, which is reflected as an adjustment to the carrying value of the Senior Notes (see table above).

Third-party Security Ratings

In 2006, third-party rating agencies performed a comprehensive review of our securities ratings based on our entrance into the new senior unsecured credit facility and the issuance of additional debt securities to facilitate the Excel acquisition. The ratings for our senior unsecured credit facility and our senior unsecured notes are as follows: Moody s issued a Ba1 rating, Standard & Poor s issued a BB rating and Fitch issued a BB+ rating. The rating on our convertible junior subordinated debentures issued in December 2006 were as follows: Moody s issued a Ba2 rating, Standard & Poor s issued a B rating and Fitch issued a BB- rating. These security ratings reflected the views of the rating agency only. An explanation of the significance of these ratings may be obtained from the rating agency. Such ratings are not a recommendation to buy, sell or hold securities, but rather an indication of creditworthiness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Shelf Registration Statement

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

Excel Transaction

On July 5, 2006, we signed a merger implementation agreement to acquire Excel Coal Limited (Excel), an independent coal company, by means of a scheme of arrangement transaction under Australian law. The merger implementation agreement was amended on September 18, 2006, and we agreed to pay A$9.50 per share (US$7.16 as of the amendment date) for the outstanding shares of Excel. On September 20, 2006, as part of the amended agreement, we acquired 19.99% of the outstanding shares of Excel at A$9.50 per share, resulting in payment of A$408.3 million, or US$307.8 million. In October 2006, we acquired the remaining interest in Excel for A$9.50 per share (US$7.07 per share), a total of A$1.63 billion or US$1.21 billion. The total acquisition price, including the advance purchase of 19.99% and related costs, was US$1.54 billion in cash plus assumed debt of US$293.0 million, less US$30.0 million of cash acquired in the transaction, and was financed with borrowings under our Senior Unsecured Credit Facility and Senior Notes due 2016 and 2026 (see Note 12 of our consolidated financial statements for additional information on the financing of the Excel acquisition). The Excel acquisition includes three operating mines (Wambo Open-Cut Mine, Metropolitan Mine and Chain Valley Mine) and three development-stage mines (North Wambo Underground Mine, Wilpinjong Mine and Millennium Mine), with more than 500 million tons of proven and probable coal reserves. We also acquired a 51.0%

interest in Excelven Pty Ltd., which owns Transportes Coal-Sea de Venezuela C.A. and a 96.7% interest in Cosila Complejo Siderurgico Del Lago S.A., which owns the Las Carmelitas coal mine development project. The results of operations of Excel are included in our Australian Mining Operations segment from October 2006. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, Business Combinations (see Note 4 of our consolidated financial statements for additional information on the Excel acquisition).

Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2006:

	Payments Due By Year			
	Within 1 Year	2-3 Years	4-5 Years	After 5 Years
	(Dollars in thousands)			
Long-term debt obligations (principal and interest)	$ 303,849	$ 481,974	$ 859,965	$ 4,323,807
Capital lease obligations (principal and interest)	11,335	21,806	15,686	23,428
Operating leases obligations	102,256	152,264	101,386	168,076
Unconditional purchase obligations[(1)]	125,791			
Coal reserve lease and royalty obligations	216,996	344,407	25,459	46,611
Other long-term liabilities[(2)]	170,716	337,809	396,113	1,362,711
Total contractual cash obligations	$ 930,943	$ 1,338,260	$ 1,398,609	$ 5,924,633

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

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

As of December 31, 2006, we had $125.8 million of purchase obligations for capital expenditures and $479.8 million of obligations related to federal coal reserve lease payments due over the next three years. Total capital expenditures for 2007 are expected to range from $450 million to $525 million, excluding federal coal reserve lease payments, and relate to replacement, improvement, or expansion of existing mines, particularly in Australia, Appalachia and the Midwest, and growth initiatives such as increasing capacity in the Powder River Basin. Approximately $10 million of the expenditures relate to safety equipment that will be utilized to comply with recently issued federal and state regulations. Capital expenditures were funded primarily through operating cash flow. Despite the acquisition of three development stage mines in 2006, we will exercise capital discipline in 2007, limiting capital expenditures to 2006 levels.

Our subsidiary, Peabody Pacific, has committed to pay up to a maximum of A$0.20/tonne (approximately US$0.15/tonne) of coal sales for a period of five years to the Australian COAL21 Fund. The COAL21 Fund is a voluntary coal industry fund to support clean coal technology demonstration projects and research in Australia. All major coal companies in Australia have committed to this fund. The commitment to pay starts on April 1, 2007 with a levy of A$0.10/tonne of coal sales. This levy is expected to rise to A$0.20/tonne on July 1, 2007.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include guarantees, indemnifications, financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds and our accounts receivable securitization. Liabilities related to these arrangements are not reflected in our consolidated balance sheets, and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

We use a combination of surety bonds, corporate guarantees (i.e. self bonds) and letters of credit to secure our financial obligations for reclamation, workers compensation, postretirement benefits and coal lease obligations as follows as of December 31, 2006:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Retiree Healthcare Obligations	Other[1]	Total
	(Dollars in millions)					
Self Bonding	$ 685.3	$	$	$	$ 2.9	$ 688.2
Surety Bonds	441.5	83.9	31.7		27.2	584.3
Letters of Credit	4.1	20.3	156.8	119.4	208.8	509.4
	$ 1,130.9	$ 104.2	$ 188.5	$ 119.4	$ 238.9	$ 1,781.9

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

As part of arrangements through which we obtain exclusive sales representation agreements with small coal mining companies (the Counterparties), we issued financial guarantees on behalf of the Counterparties. These guarantees facilitate the Counterparties efforts to obtain bonding or financing. In July 2006, we issued $5.2 million of financial guarantees, expiring at various dates through July 2013, on behalf of a small coal producer to facilitate its efforts in obtaining financing. In the event of default, we have multiple recourse options, including the ability to assume the loans and procure title and use of the equipment purchased through the loans. If default occurs, we have the ability and intent to exercise our recourse options, so the liability associated with the guarantee has been valued at zero. We have also guaranteed bonding for a partnership in which we formerly held an interest. The aggregate amount guaranteed for all such Counterparties was $12.1 million, and the fair value of the guarantees recognized as a liability was $0.4 million as of December 31, 2006. Our obligations under the guarantees extend to September 2015. In March 2006, we issued a guarantee for certain equipment lease arrangements on behalf of one of the sales representation parties with maximum potential future payments totaling $2.7 million at December 31, 2006, and with lease terms that extend to April 2010. See Note 21 to our consolidated financial statements included in this report for a discussion of our guarantees.

Under our accounts receivable securitization program, undivided interests in a pool of eligible trade receivables contributed to our wholly-owned, bankruptcy-remote subsidiary are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit (Conduit). Purchases by the Conduit are financed with the sale of highly rated commercial paper. We utilize proceeds from the sale of our accounts receivable as an alternative to other forms of debt, effectively reducing our overall borrowing costs. The funding cost of the securitization program was $1.9 million and $2.5 million for the years ended December 31, 2006 and 2005, respectively. The securitization program is scheduled to expire in September 2009. The securitization transactions have been recorded as sales, with those accounts receivable sold to the Conduit removed from the consolidated balance sheets. The amount of undivided interests in accounts receivable sold to the Conduit was $219.2 million and $225.0 million as of December 31, 2006 and 2005 (see Note 6 to our consolidated financial statements for additional information on accounts receivable securitization).

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The following is a summary of specified types of commercial commitments available to us as of December 31, 2006:

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

Newly Adopted Accounting Pronouncements

We adopted Emerging Issues Task Force (EITF) Issue No. 04-6, Accounting for Stripping Costs in the Mining Industry (EITF Issue No. 04-6) on January 1, 2006 and utilized the cumulative effect adjustment approach whereby a cumulative effect adjustment reduced retained earnings by $150.3 million, net of tax. EITF Issue No. 04-6 states that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. Advance stripping costs include those costs necessary to remove overburden above an unmined coal seam as part of the surface mining process and prior to the adoption were included as the work-in-process component of Inventories in the consolidated balance sheet. EITF Issue No. 04-6 and its interpretations require stripping costs incurred during a period to be attributed only to the inventory costs of the coal that is extracted during that same period, and therefore, advance stripping costs are no longer separately classified as a component of inventory.

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment (SFAS No. 123(R)), which is a revision of SFAS No. 123, Accounting for Stock-Based Compensation (SFAS No. 123). SFAS No. 123(R) supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees (APB Opinion No. 25) and amends SFAS No. 95, Statement of Cash Flows. Prior to January 1, 2006, we applied APB Opinion No. 25 and related interpretations in accounting for our stock option plans, as permitted under SFAS No. 123 and SFAS No. 148 Accounting for Stock-Based Compensation-Transition and Disclosure. We applied SFAS No. 123(R) through use of the modified prospective method, in which compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS No. 123(R) for all share-based payments granted or modified after the effective date and (b) based on the requirements of SFAS No. 123 for all awards granted to employees prior to the effective date of SFAS No. 123(R) that remain unvested on the effective date. SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values at the grant date. SFAS No. 123(R) also requires that the excess income tax benefits from stock options exercised be recorded as financing cash inflow on the statements of cash flows. The excess income tax benefit from stock option exercises during 2005 and 2004 are included in operating cash flows, netted in deferred tax activity.

For share-based payment instruments excluding restricted stock, we recognized $17.7 million (or $0.07 per diluted share), $24.8 million (or $0.09 per diluted share) and $12.8 million (or $0.05 per diluted share) of expense, net of taxes, for the years ended December 31, 2006, 2005 and 2004, respectively. As a result of adopting SFAS No. 123(R), our net income for the year ended December 31, 2006 was $4.4 million (or $0.02 per diluted share) lower than if we had continued to account for share-based compensation under APB Opinion No. 25. Share-based compensation expense is recorded in Selling and administrative expenses in the consolidated statements of operations. We used the Black-Scholes option pricing model to determine the fair value of stock options and employee stock purchase plan share-based payments made before and after the adoption of SFAS No. 123(R). We began utilizing restricted stock as part of our equity-based compensation strategy in January 2005. Accounting for restricted stock awards was not changed by the adoption of SFAS No. 123(R). As of December 31, 2006, the total unrecognized compensation cost related to nonvested awards was $24.0 million, net of taxes, which is expected to be recognized over 5.0 years with a weighted-average period of 1.3 years. See Note 18 to our consolidated financial statements for further discussion of our share-based compensation plans.

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

We adopted SFAS No. 158 on December 31, 2006, and as a result, recorded a noncurrent liability of $376.1 million, which reflected the total underfunded status of the pension, retiree healthcare and workers compensation plans. The funded status of each plan was measured as the difference between the fair value of the assets and the projected benefit obligation (the funded status). SFAS No. 158 did not impact net income. The impact to the balance sheet was as follows (see Notes 14, 15, and 16 to our consolidated financial statements for additional details):

	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
		(Dollars in thousands)	
Workers compensation obligations	$ 237,965	$ (4,558)	$ 233,407
Accrued postretirement benefit costs	973,164	395,522	1,368,686
Other noncurrent liabilities (includes long-term pension and UMWA Combined Fund liabilities)	375,485	(14,855)	360,630
Deferred income taxes (long-term liability)	344,712	(149,499)	195,213
Total liabilities	6,915,583	226,610	7,142,193
Accumulated other comprehensive loss	(22,448)	(226,610)	(249,058)
Total stockholders equity	2,565,136	(226,610)	2,338,526

Accounting Pronouncements Not Yet Implemented

In June 2006, the FASB issued FIN No. 48. This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006 (January 1, 2007 for the Company). Any adjustments required upon the adoption of this interpretation must be recorded directly to retained earnings in the year of adoption and reported as a change in accounting principle. We expect the adoption of FIN No. 48 will not have a material impact on our financial position.

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

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

Coal Trading Activities and Related Commodity Price Risk

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

We account for coal trading using the fair value method, which requires us to reflect financial instruments with third parties, such as forwards, options and swaps, at market value in our consolidated financial statements. Our trading portfolio included forwards and swaps as of December 31, 2006 and forwards as of December 31, 2005.

We perform a value at risk analysis on our coal trading portfolio, which includes over-the-counter and brokerage trading of coal. The use of value at risk allows us to quantify in dollars, on a daily basis, the price risk inherent in our trading portfolio. Value at risk represents the potential loss in value of our mark-to-market portfolio due to adverse market movements over a defined time horizon (liquidation period) within a specified confidence level. Our value at risk model is based on the industry standard variance/co-variance approach. This captures our exposure related to both option and forward positions. Our value at risk model assumes a 15-day holding period and a 95% one-tailed confidence interval. This means that there is a one in 20 statistical chance that the portfolio would lose more than the value at risk estimates during the liquidation period.

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

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

During the year ended December 31, 2006, the actual low, high, and average values at risk for our coal trading portfolio were $0.7 million, $2.7 million, and $1.4 million, respectively. As of December 31, 2006, the timing of the estimated future realization of the value of our trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio
2007	41%
2008	39%
2009	15%
2010	5%
	100%

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

Credit Risk

Our concentration of credit risk is substantially with energy producers and marketers and electric utilities. Our policy is to independently evaluate each customer s creditworthiness prior to entering into

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transactions and to constantly monitor the credit extended. In the event that we engage in a transaction with a counterparty that does not meet our credit standards, we will protect our position by requiring the counterparty to provide appropriate credit enhancement. When appropriate (as determined by our credit management function), we have taken steps to reduce our credit exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk of failure to perform under their contractual obligations. These steps include obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for our benefit to serve as collateral in the event of a failure to pay. To reduce our credit exposure related to trading and brokerage activities, we seek to enter into netting agreements with counterparties that permit us to offset receivables and payables with such counterparties. Counterparty risk with respect to interest rate swap and foreign currency forwards and options transactions is not considered to be significant based upon the creditworthiness of the participating financial institutions.

Foreign Currency Risk

We utilize currency forwards to hedge currency risk associated with anticipated Australian dollar expenditures. Our currency hedging program for 2007 targets hedging approximately 70% of our anticipated, non-capital Australian dollar-denominated expenditures. As of December 31, 2006, we had in place forward contracts designated as cash flow hedges with notional amounts outstanding totaling A$1.35 billion of which A$764.2 million, A$359.7 million, A$196.7 million and A$28.8 million will expire in 2007, 2008, 2009, and 2010, respectively. The accounting for these derivatives is discussed in Note 2 to our consolidated financial statements. Our current expectation for 2007 non-capital, Australian dollar-denominated cash expenditures is approximately $1.37 billion. An increase or decrease in the Australian dollar/ U.S. dollar exchange rate of US$0.01 (ignoring the effects of hedging) would result in an increase or decrease, respectively, in our Operating costs and expenses of $13.7 million per year.

Interest Rate Risk

Our objectives in managing exposure to interest rate changes are to limit the impact of interest rate changes on earnings and cash flows and to lower overall borrowing costs. To achieve these objectives, we manage fixed-rate debt as a percent of net debt through the use of various hedging instruments, which are discussed in detail in Note 12 to our consolidated financial statements. As of December 31, 2006, after taking into consideration the effects of interest rate swaps, we had $2.61 billion of fixed-rate borrowings and $649.3 million of variable-rate borrowings outstanding. A one percentage point increase in interest rates would result in an annualized increase to interest expense of $6.5 million on our variable-rate borrowings. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a $0.2 million decrease in the estimated fair value of these borrowings.

Other Non-trading Activities

We manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements, rather than through the use of derivative instruments. We sold 90% of our sales volume under long-term coal supply agreements during 2006 and 2005. As of December 31, 2006, we had 5 to 15 million tons of expected U.S. production unpriced for 2007. We had 14 million tons remaining to be priced in Australia at December 31, 2006. We have approximately 70 to 80 million tons of expected U.S. production unpriced for 2008, with an additional 20 to 22 million tons of expected Australia coal production.

Some of the products used in our mining activities, such as diesel fuel and explosives, are subject to commodity price risk. To manage this risk, we use a combination of forward contracts with our suppliers and financial derivative contracts, primarily swap contracts with financial institutions. As of December 31, 2006, we had derivative contracts outstanding that are designated as cash flow hedges of anticipated purchases of fuel and explosives.

Notional amounts outstanding under fuel-related, derivative swap contracts were 11.6 million gallons of heating oil scheduled to expire through 2007 and 83.2 million gallons of crude oil scheduled to expire through 2009. At December 31, 2006, we had outstanding option contracts designated as a collar of crude oil prices with notional amounts of 43.1 million gallons, expiring through 2007. We expect to consume 100 to 105 million gallons of fuel next year. On a per gallon basis, based on this usage, a change in fuel prices of one cent per gallon (ignoring the effects of hedging) would result in an increase or decrease in our operating costs of approximately $1 million per year. Alternatively, a one dollar per barrel change in the price of crude oil would increase or decrease our annual fuel costs (ignoring the effects of hedging) by approximately $2.4 million.

Notional amounts outstanding under explosives-related swap contracts, scheduled to expire through 2009, were 5.7 mmbtu of natural gas. We expect to consume 315,000 to 325,000 tons of explosives per year. Through our natural gas hedge contracts, we have fixed prices for approximately 46% of our anticipated explosives requirements for 2007. Based on our expected usage, a change in natural gas prices of ten cents per mmbtu (ignoring the effects of hedging) would result in an increase or decrease in our operating costs of approximately $0.6 million per year.

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

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

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

None.

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

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Annual Report on Form 10-K, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective in timely alerting them to material information relating to our company and its consolidated subsidiaries required to be included in our periodic SEC filings.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting identified during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management s Report on Internal Control Over Financial Reporting

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

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

Management conducted an assessment of the effectiveness of our internal control over financial reporting using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Based on this assessment, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2006.

Management s assessment of internal control over financial reporting excludes the operations of Excel Coal Limited acquired during 2006, as allowed by SEC guidance related to internal controls of recently acquired entities. These operations constituted $2.34 billion and $1.58 billion of total and net assets, respectively; and $105.1 million and $8.4 million of revenues and operating profits, respectively; and such amounts are included in our consolidated financial statements as of and for the year ended December 31, 2006. Management did not assess the effectiveness of internal control over financial reporting at these operations because we continue to integrate these operations into our control environment, thus making it impractical to complete an assessment by December 31, 2006.

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

/s/ GREGORY H. BOYCE	/s/ RICHARD A. NAVARRE
Gregory H. Boyce President and Chief Executive Officer	Richard A. Navarre Chief Financial Officer and Executive Vice President of Corporate Development

February 20, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited management s assessment, included in the accompanying Management s Report on Internal Controls, that Peabody Energy Corporation maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Peabody Energy Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

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

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

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

As indicated in the accompanying Management s Report on Internal Control Over Financial Reporting, management s assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls over Excel Coal Limited acquired in 2006, which is included in the December 31, 2006, consolidated financial statements of Peabody Energy Corporation and constituted $2.34 billion and $1.58 billion of total and net assets, respectively, as of December 31, 2006, and $105.1 million and $8.4 million of revenues and operating profits, respectively, for the year then ended. Our audit of internal control over financial reporting of Peabody Energy Corporation also did not include an evaluation of the internal control over financial reporting of Excel Coal Limited.

In our opinion, management s assessment that Peabody Energy Corporation maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Peabody Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Peabody Energy Corporation as of

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December 31, 2006 and 2005, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006, and our report dated February 20, 2007, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 20, 2007

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

None.

PART III

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

The information required by Item 401 of Regulation S-K is included under the caption Election of Directors in our 2007 Proxy Statement and in Part I of this report under the caption Executive Officers of the Company. The information required by Item 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions Ownership of Company Securities Section 16(a) Beneficial Ownership Reporting Compliance, Corporate Governance Matters and Information Regarding Board of Directors and Committees in our 2007 Proxy Statement. Such information is incorporated herein by reference.

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

The information required by Items 402 and 407 (e)(4) and (e)(5) of Regulation S-K is included under the captions Executive Compensation, Compensation Committee Interlocks and Insider Participation and Report of the Compensation Committee in our 2007 Proxy Statement and is incorporated herein by reference.

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

The information required by Item 403 of Regulation S-K is included under the caption Ownership of Company Securities in our 2007 Proxy Statement and is incorporated herein by reference.

Equity Compensation Plan Information

As required by Item 201(d) of Regulation S-K, the following table provides information regarding our equity compensation plans as of December 31, 2006:

Plan Category	(a) Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	9,320,718	$8.16	14,967,519
Equity compensation plans not approved by security holders			
Total	9,320,718	$8.16	14,967,519

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

The information required by Items 404 and 407(a) of Regulation S-K is included under the captions Certain Transactions and Relationships and Information Regarding Board of Directors and Committees in our 2007 Proxy Statement and is incorporated herein by reference.

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

The information required by Item 9(e) of Schedule 14A is included under the caption Appointment of Independent Registered Public Accounting Firm and Fees in our 2007 Proxy Statement and is incorporated herein by reference.

PART IV

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

(a) Documents Filed as Part of the Report

(1) Financial Statements.

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

(2) Financial Statement Schedule.

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

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

(3) Exhibits.

See Exhibit Index hereto.

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SIGNATURES

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

PEABODY ENERGY CORPORATION

/s/ GREGORY H. BOYCE

Gregory H. Boyce
President, Chief Executive Officer and Director

Date: February 28, 2007

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

Signature	Title	Date
/s/ GREGORY H. BOYCE Gregory H. Boyce	President, Chief Executive Officer and Director (principal executive officer)	February 28, 2007
/s/ RICHARD A. NAVARRE Richard A. Navarre	Chief Financial Officer and Executive Vice President of Corporate Development (principal financial and accounting officer)	February 28, 2007
/s/ IRL F. ENGELHARDT Irl F. Engelhardt	Chairman	February 28, 2007
/s/ B.R. BROWN B.R. Brown	Director	February 28, 2007
/s/ WILLIAM A. COLEY William A. Coley	Director	February 28, 2007
/s/ HENRY GIVENS, JR., PhD Henry Givens, Jr., PhD	Director	February 28, 2007
/s/ WILLIAM E. JAMES William E. James	Director	February 28, 2007
/s/ ROBERT B. KARN III Robert B. Karn III	Director	February 28, 2007

/s/ HENRY E. LENTZ Henry E. Lentz	Director	February 28, 2007
/s/ WILLIAM C. RUSNACK William C. Rusnack	Director	February 28, 2007

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Signature	Title	Date
/s/ JAMES R. SCHLESINGER, PhD James R. Schlesinger, PhD	Director	February 28, 2007
/s/ BLANCHE M. TOUHILL, PhD Blanche M. Touhill, PhD	Director	February 28, 2007
/s/ JOHN F. TURNER John F. Turner	Director	February 28, 2007
/s/ SANDRA VAN TREASE Sandra Van Trease	Director	February 28, 2007
/s/ ALAN H. WASHKOWITZ Alan H. Washkowitz	Director	February 28, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited the accompanying consolidated balance sheets of Peabody Energy Corporation as of December 31, 2006 and 2005, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Peabody Energy Corporation at December 31, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Peabody Energy Corporation s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 20, 2007, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 20, 2007

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands, except share and per share data)		
Revenues			
Sales	$ 5,144,925	$ 4,545,323	$ 3,545,027
Other revenues	111,390	99,130	86,555
Total revenues	5,256,315	4,644,453	3,631,582
Costs and Expenses			
Operating costs and expenses	4,155,984	3,715,836	2,965,541
Depreciation, depletion and amortization	377,210	316,114	270,159
Asset retirement obligation expense	40,112	35,901	42,387
Selling and administrative expenses	175,941	189,802	143,025
Other operating income:			
Net gain on disposal or exchange of assets	(132,162)	(101,487)	(23,829)
Income from equity affiliates	(23,852)	(30,096)	(12,399)
Operating Profit	663,082	518,383	246,698
Interest expense	143,450	102,939	96,793
Early debt extinguishment costs	1,396		1,751
Interest income	(12,726)	(10,641)	(4,917)
Income From Continuing Operations Before Income Taxes and Minority Interests	530,962	426,085	153,071
Income tax provision (benefit)	(81,515)	960	(26,437)
Minority interests	11,780	2,472	1,282
Income From Continuing Operations	600,697	422,653	178,226
Loss from discontinued operations, net of income tax benefit of $1,893			(2,839)
Net Income	$ 600,697	$ 422,653	$ 175,387
Basic Earnings Per Share			
Income from continuing operations	$ 2.28	$ 1.62	$ 0.72
Loss from discontinued operations			(0.01)
Net income	$ 2.28	$ 1.62	$ 0.71
Weighted Average Shares Outstanding Basic	263,419,344	261,519,424	248,732,744
Diluted Earnings Per Share			
Income from continuing operations	$ 2.23	$ 1.58	$ 0.70
Loss from discontinued operations			(0.01)

Net income	$	2.23	$	1.58	$	0.69
Weighted Average Shares Outstanding Diluted		269,166,005		268,013,476		254,812,632
Dividends Declared Per Share	$	0.24	$	0.17	$	0.13

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2006	2005
	(Dollars in thousands, except share and per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 326,511	$ 503,278
Accounts receivable, net of allowance for doubtful accounts of $11,144 and $10,853 at December 31, 2006 and 2005, respectively	358,242	202,134
Inventories	215,384	389,771
Assets from coal trading activities	150,373	146,596
Deferred income taxes	106,967	9,027
Other current assets	116,863	54,431
Total current assets	1,274,340	1,305,237
Property, plant, equipment and mine development		
Land and coal interests	7,127,385	4,775,126
Buildings and improvements	893,049	793,254
Machinery and equipment	1,516,765	1,237,184
Less accumulated depreciation, depletion and amortization	(1,985,682)	(1,627,856)
Property, plant, equipment and mine development, net	7,551,517	5,177,708
Goodwill	240,667	
Investments and other assets	447,532	369,061
Total assets	$ 9,514,056	$ 6,852,006
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 95,757	$ 22,585
Liabilities from coal trading activities	126,731	132,373
Accounts payable and accrued expenses	1,145,043	867,965
Total current liabilities	1,367,531	1,022,923
Long-term debt, less current maturities	3,168,069	1,382,921
Deferred income taxes	195,213	338,488
Asset retirement obligations	423,031	399,203
Workers compensation obligations	233,407	237,574
Accrued postretirement benefit costs	1,368,686	959,222
Other noncurrent liabilities	386,256	330,658
Total liabilities	7,142,193	4,670,989
Minority interests	33,337	2,550

Stockholders equity				
Preferred Stock $0.01 per share par value; 10,000,000 shares authorized, no shares issued or outstanding as of December 31, 2006 or 2005				
Series A Junior Participating Preferred Stock 1,500,000 shares authorized, no shares issued or outstanding as of December 31, 2006 or 2005				
Perpetual Preferred Stock 750,000 shares authorized, no shares issued or outstanding as of December 31, 2006 or 2005				
Series Common Stock $0.01 per share par value; 40,000,000 shares authorized, no shares issued or outstanding as of December 31, 2006 or 2005				
Common Stock $0.01 per share par value; 800,000,000 shares authorized, 266,554,157 shares issued and 263,846,839 shares outstanding as of December 31, 2006 and 400,000,000 shares authorized, 263,879,762 shares issued and 263,357,402 shares outstanding as of December 31, 2005		2,666		2,638
Additional paid-in capital		1,572,614		1,497,454
Retained earnings		1,115,994		729,086
Accumulated other comprehensive loss		(249,058)		(46,795)
Treasury shares, at cost: 2,707,318 shares as of December 31, 2006 and 522,360 shares as of December 31, 2005		(103,690)		(3,916)
Total stockholders equity		2,338,526		2,178,467
Total liabilities and stockholders equity	$	9,514,056	$	6,852,006

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands)		
Cash Flows From Operating Activities			
Net income	$ 600,697	$ 422,653	$ 175,387
Loss from discontinued operations			2,839
Income from continuing operations	600,697	422,653	178,226
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	377,210	316,114	270,159
Deferred income taxes	(189,243)	(24,962)	(31,925)
Amortization of debt discount and debt issuance costs	7,410	6,938	8,330
Net gain on disposal or exchange of assets	(132,162)	(101,487)	(23,829)
Income from equity affiliates	(23,852)	(30,096)	(12,399)
Dividends received from equity affiliates	28,063	7,552	13,614
Changes in current assets and liabilities, net of acquisitions:			
Accounts receivable, net of sale	(103,399)	(52,757)	(34,649)
Inventories	(38,208)	(67,125)	(57,781)
Net assets from coal trading activities	(9,419)	11,377	(3,583)
Other current assets	(24,108)	(10,769)	(1,438)
Accounts payable and accrued expenses	88,014	173,919	66,576
Asset retirement obligations	(52)	(981)	(6,571)
Workers compensation obligations	391	11,390	10,479
Accrued postretirement benefit costs	13,942	19,719	(32,499)
Contributions to pension plans	(6,146)	(7,162)	(62,082)
Other, net	6,588	28,436	3,132
Net cash provided by operating activities	595,726	702,759	283,760
Cash Flows From Investing Activities			
Acquisition of Excel Coal, net of cash acquired	(1,507,775)		
Other acquisitions, net	(44,538)		(429,061)
Additions to property, plant, equipment and mine development	(477,721)	(384,304)	(151,944)
Purchase of mining and related assets		(141,195)	
Federal coal lease expenditures	(178,193)	(118,364)	(114,653)
Proceeds from disposal of assets, net of notes receivable	77,579	76,227	39,339
Additions to advance mining royalties	(11,021)	(14,566)	(16,239)
Investments in joint ventures	(2,149)	(2,000)	(32,472)
Net cash used in investing activities	(2,143,818)	(584,202)	(705,030)
Cash Flows From Financing Activities			
Proceeds from long-term debt	2,580,295	11,734	700,013

Payments of long-term debt	(1,045,973)	(20,198)	(482,924)
Common stock repurchase	(99,774)		
Dividends paid	(63,456)	(44,535)	(32,568)
Payment of debt issuance costs	(40,611)		(12,875)
Excess tax benefit related to stock options exercised	33,173		
Net proceeds from equity offering			383,125
Proceeds from stock options exercised	15,617	22,573	27,266
Distributions to minority interests	(6,664)	(2,498)	(1,007)
Increase (decrease) of securitized interests in accounts receivable	(5,800)	25,000	110,000
Proceeds from employee stock purchases	4,518	3,009	2,374
Net cash provided by (used in) financing activities	1,371,325	(4,915)	693,404
Net increase (decrease) in cash and cash equivalents	(176,767)	113,642	272,134
Cash and cash equivalents at beginning of year	503,278	389,636	117,502
Cash and cash equivalents at end of year	$ 326,511	$ 503,278	$ 389,636

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

	Common Stock	Additional Paid-In Capital	Other Employee Stock Loans	Accumulated Other Comprehensive Loss	Retained Earnings	Treasury Stock	Total Stockholders Equity
				(Dollars in thousands)			
December 31, 2003	$ 2,190	$ 1,007,008	$ (31)	$ (81,572)	$ 208,149	$ (3,687)	$ 1,132,057
Comprehensive income:							
Net income					175,387		175,387
Increase in fair value of cash flow hedges (net of $9,945 tax provision)				14,915			14,915
Minimum pension liability adjustment (net of $4,026 tax provision)				6,039			6,039
Comprehensive income							196,341
Issuance of common stock in connection with equity offering, net of expenses	352	382,773					383,125
Dividends paid					(32,568)		(32,568)
Loan repayments			31				31
Stock options exercised	54	27,621					27,675
Income tax benefits from stock options exercised		15,718					15,718
Employee stock purchases		2,343					2,343
Employee stock grants							
Share-based compensation		99					99
Shares repurchased						(229)	(229)
December 31, 2004	$ 2,596	$ 1,435,562	$	$ (60,618)	$ 350,968	$ (3,916)	$ 1,724,592
Comprehensive income:							
Net income					422,653		422,653
Increase in fair value of cash flow hedges (net of $7,613 tax provision)				11,421			11,421

Minimum pension liability adjustment (net of $1,601 tax provision)				2,402			2,402
Comprehensive income							436,476
Dividends paid					(44,535)		(44,535)
Stock options exercised	36	22,627					22,663
Income tax benefits from stock options exercised		30,437					30,437
Employee stock purchases	2	3,007					3,009
Employee stock grants	4	(4)					
Share-based compensation		5,825					5,825
December 31, 2005	$ 2,638	$ 1,497,454	$	$ (46,795)	$ 729,086	$ (3,916)	$ 2,178,467
Comprehensive income:							
Net income					600,697		600,697
Increase in fair value of cash flow hedges (net of $16,230 tax provision)				24,347			24,347
Minimum pension liability adjustment (net of $16,842 tax provision)				22,377			22,377
Comprehensive income							647,421
Postretirement plans and workers compensation obligations (net of $149,499 tax benefit):							
Accumulated actuarial loss, net of tax				(241,954)			
Prior service cost, net of tax				(7,033)			
				(248,987)			(248,987)
Dividends paid					(63,456)		(63,456)
Stock options exercised	20	15,600					15,620
Share-based compensation		21,877					21,877
Income tax benefits from stock options exercised		33,173					33,173
	2	4,516					4,518

Employee stock purchases								
Employee stock grants	6	(6)						
Advance stripping adjustment (net of $95,189 tax benefit)						(150,333)		(150,333)
Shares repurchased							(99,774)	(99,774)
December 31, 2006	$ 2,666	$ 1,572,614	$	$	(249,058)	$ 1,115,994	$ (103,690)	$ 2,338,526

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

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

Description of Business

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

New Accounting Pronouncements

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

The Company adopted SFAS No. 158 on December 31, 2006, and as a result, recorded a noncurrent liability of $376.1 million, which reflected the net underfunded status of the pension, retiree healthcare and workers compensation plans. The funded status of each plan was measured as the difference between the fair value of the assets and the projected benefit obligation (the funded status). SFAS No. 158 did not impact net income. The impact to the balance sheet was as follows (see Notes 14, 15, and 16 for additional details):

	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
		(Dollars in thousands)	
Workers compensation obligations	$ 237,965	$ (4,558)	$ 233,407
Accrued postretirement benefit costs	973,164	395,522	1,368,686
Other noncurrent liabilities (includes long-term pension and UMWA Combined Fund liabilities)	375,485	(14,855)	360,630
Deferred income taxes (long-term liability)	344,712	(149,499)	195,213
Total liabilities	6,915,583	226,610	7,142,193
Accumulated other comprehensive loss	(22,448)	(226,610)	(249,058)
Total stockholders equity	2,565,136	(226,610)	2,338,526

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN No. 48). This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006 (January 1, 2007 for the Company). Any adjustments required upon the adoption of this interpretation must be recorded directly to retained earnings in the year of adoption and reported as a change in accounting principle. The Company expects the adoption of FIN No. 48 will not have a material impact on its results of operations or financial position.

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

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

The Company adopted SFAS No. 123(R) on January 1, 2006 and used the modified prospective method, in which compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS No. 123(R) for all share-based payments granted or modified after the effective date and (b) based on the requirements of SFAS No. 123 for all awards granted to employees prior to the effective date of SFAS No. 123(R) that remain unvested on the effective date. Prior to January 1, 2006, the Company had elected to apply APB Opinion No. 25 and related interpretations in accounting for its stock option plans, as permitted under SFAS No. 123 and SFAS No. 148 Accounting for Stock-Based Compensation-Transition and Disclosure. Beginning in 2006, SFAS No. 123(R) also requires that excess income tax benefits from stock options exercised be recorded as financing cash inflow on the statements of cash flows. The excess income tax benefit from stock option exercises during 2005 and 2004 is included in operating cash flows, netted in deferred tax activity.

Sales

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

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Revenues

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

Discontinued Operations

The Company classifies items within discontinued operations in the consolidated statements of operations when the operations and cash flows of a particular component (defined as operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the entity) of the Company have been (or will be) eliminated from the ongoing operations of the Company as a result of a disposal transaction, and the Company will no longer have any significant continuing involvement in the operations of that component. Discontinued operations for the year ended December 31, 2004, reflected a $2.8 million loss, net of taxes, related to the Company s former Citizens Power subsidiary.

Cash and Cash Equivalents

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

Inventories

Materials and supplies and coal inventory are valued at the lower of average cost or market. Raw coal represents coal stockpiles that may be sold in current condition or may be further processed prior to shipment to a customer. Coal inventory costs include labor, supplies, equipment, operating overhead and other related costs. Prior to the adoption of EITF Issue No. 04-6, advance stripping consisted of the costs to remove overburden above an unmined coal seam as part of the surface mining process. As a result of the adoption of EITF Issue No. 04-6 on January 1, 2006, advance stripping costs are primarily expensed as incurred.

Assets and Liabilities from Coal Trading Activities

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

The Company s trading contracts are reflected at fair value and are included in Assets and liabilities from coal trading activities in the consolidated balance sheets as of December 31, 2006 and 2005. Under EITF Issue No. 02-3, all mark-to-market gains and losses on energy trading contracts (including derivatives and hedged contracts) are presented on a net basis in the statement of operations, even if

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

settled physically. The Company s consolidated statements of operations reflect revenues related to all mark-to-market trading contracts on a net basis in Other revenues.

Property, Plant, Equipment and Mine Development

Property, plant, equipment and mine development are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period, including $3.0 million, $0.1 million and $0.2 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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

Coal reserves are recorded at cost, or at fair value in the case of acquired businesses. As of December 31, 2006 and 2005, the net book value of coal reserves totaled $5.2 billion and $3.7 billion, respectively. These amounts included $2.1 billion and $1.8 billion at December 31, 2006 and 2005, respectively, attributable to properties where the Company was not currently engaged in mining operations or leasing to third parties and, therefore, the coal reserves were not currently being depleted. Included in the book value of coal reserves are mineral rights for leased coal interests including advance royalties and the net book value of these mineral rights was $3.5 billion and $2.1 billion at December 31, 2006 and 2005, respectively.

Depletion of coal reserves and amortization of advance royalties is computed using the units-of-production method utilizing only proven and probable reserves in the depletion base. Mine development costs are principally amortized over the estimated lives of the mines using the straight-line method.

Depreciation of plant and equipment (excluding life of mine assets) is computed using the straight-line method over the estimated useful lives as follows:

	Years
Building and improvements	10 to 30
Machinery and equipment	3 to 30
Leasehold improvements	Life of Lease

In addition, certain plant and equipment assets associated with mining are depreciated using the straight-line method over the estimated life of the mine, which varies from one to 33 years.

Goodwill and Intangible Assets

Assets and liabilities acquired in business combinations are accounted for using the purchase method and recorded at their respective fair values. Substantially all goodwill is assigned to the reporting unit that acquires a business. A reporting unit is an operating segment as defined in SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information, or a business one level below an operating segment if discrete financial information is prepared and regularly reviewed by the segment manager. The Company conducts a formal impairment test of goodwill on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. Under the impairment test, if a reporting unit s carrying amount exceeds its estimated fair value, a goodwill impairment is recognized to the extent that the reporting unit s carrying amount of goodwill exceeds the implied fair value of the goodwill.

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All of the Company s intangibles (other than goodwill) are subject to amortization. Intangibles consist of contractual obligations and are amortized based on tons sold. These intangibles are also subject to evaluation for potential impairment if an event occurs or circumstances change that indicate the carrying amount may not be recoverable.

Investments in Joint Ventures

The Company accounts for its investments in less than majority owned corporate joint ventures under either the equity or cost method. The Company applies the equity method to investments in joint ventures when it has the ability to exercise significant influence over the operating and financial policies of the joint venture. Investments accounted for under the equity method are initially recorded at cost, and any difference between the cost of the Company s investment and the underlying equity in the net assets of the joint venture at the investment date is amortized over the lives of the related assets that gave rise to the difference. The Company s pro rata share of earnings from joint ventures and basis difference amortization is reported in the consolidated statements of operations in Income from equity affiliates. The book value of the Company s equity method investments as of December 31, 2006 and 2005 was $65.5 million and $97.2 million, respectively, and is reported in Investments and other assets in the consolidated balance sheets. Included in the Company s equity method investments was its 25.5% interest in Carbones del Guasare, which owns and operates the Paso Diablo Mine in Venezuela. The Company s investment in Paso Diablo was $60.1 million and $50.3 million as of December 31, 2006 and 2005, respectively. The Company recorded income from this equity affiliate of $28.0 million, $20.0 million and $1.2 million for the years ended December 31, 2006, 2005 and 2004, respectively, which is reported in Income from equity affiliates in the consolidated statements of operations.

Generation Development Costs

Development costs related to coal-based electricity generation, including expenditures for permitting and licensing, are capitalized at cost under the guidelines in SFAS No. 142, Goodwill and Other Intangible Assets. Start-up costs, as defined in Statement of Position (SOP) No. 98-5, Reporting on the Costs of Start-up Activities, are expensed as incurred. Development costs of $21.4 million and $22.4 million were recorded as part of Investments and other assets in the consolidated balance sheets as of December 31, 2006 and 2005, respectively.

Asset Retirement Obligations

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

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

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

adjusted risk-free rate. The Company also recognizes an obligation for contemporaneous reclamation liabilities incurred as a result of surface mining. Contemporaneous reclamation consists primarily of grading, topsoil replacement and revegetation of backfilled pit areas.

Environmental Liabilities

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

Income Taxes

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

Postretirement Health Care and Life Insurance Benefits

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

Multi-Employer Benefit Plans

The Company has an obligation to contribute to two plans established by the Coal Industry Retiree Health Benefits Act of 1992 (the Coal Act) the Combined Fund and the 1992 Benefit Plan . A third fund, the 1993 Benefit Fund (the 1993 Benefit Plan), was originally established through collective bargaining, but is now a statutory plan under the terms of the 2006 Tax Relief and Health Care Act. The Combined Fund obligations are accounted for in accordance with EITF Issue No. 92-13, Accounting for Estimated Payments in Connection with the Coal Industry Retiree Health Benefit Act of 1992, as determined on an actuarial basis. The 1992 Benefit Plan and 1993 Benefit Plan qualify as multi-employer plans under SFAS No. 106 and expense is recognized as contributions are made.

Pension Plans

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

The Company also participates in two multi-employer pension plans, the United Mine Workers of America 1950 Pension Plan (the 1950 Plan) and the United Mine Workers of America 1974 Pension Plan (the 1974 Plan). These plans qualify as multi-employer plans under SFAS No. 87 and expense is recognized as contributions are made.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Postemployment Benefits

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

Derivatives

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

Gains or losses on derivative financial instruments designated as cash flow hedges are recorded as a separate component of stockholders equity until settlement (or until hedge ineffectiveness is determined), whereby gains or losses are reclassified to the consolidated statements of operations in conjunction with the recognition of the underlying hedged item. To the extent that the periodic changes in the fair value of the derivatives are not effective, or if the hedge ceases to qualify for hedge accounting, the ineffective portion of the periodic non-cash changes are recorded in Operating costs and expenses in the consolidated statement of operations in the period of the change. The potential for hedge ineffectiveness is only present in the design of the hedge relationship in the Company s cash flow hedges of anticipated fuel purchases (see Note 2 for additional details).

Use of Estimates in the Preparation of the Consolidated Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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

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

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Impairment of Long-Lived Assets

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

Fair Value of Financial Instruments

SFAS No. 107, Disclosures About Fair Value of Financial Instruments, defines the fair value of a financial instrument as the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced or liquidation sale. See Note 22 for additional information.

Foreign Currency Translation

For the Company s foreign subsidiaries where the functional currency is the U.S. dollar, monetary assets and liabilities are translated at year-end exchange rates while non-monetary items are translated at historical rates. Income and expense accounts are translated at the average rates in effect during the year, except for those expenses related to balance sheet amounts that are remeasured at historical exchange rates. The Company has foreign subsidiaries whose functional currency is the U.S. dollar during the years ended December 31, 2006, 2005, and 2004. Gains and losses from foreign currency remeasurement are included in the consolidated statements of operations. The foreign currency remeasurement loss for the year ended December 31, 2006 was $12.8 million. Gains and losses from foreign currency remeasurement did not have a material impact on the Company s consolidated financial position or results of operations for the years ended December 31, 2005 and 2004.

(2) Risk Management and Derivative Financial Instruments

The Company is exposed to various types of risk in the normal course of business, including fluctuations in commodity prices, interest rates and foreign currency exchange rates. These risks are actively monitored to ensure compliance with the risk management policies of the Company. In most cases, commodity price risk (excluding coal trading activities) related to the sale of coal is mitigated through the use of long-term, fixed-price contracts rather than financial instruments, while commodity price risk related to materials used in production is managed through the use of fixed price and cost plus contracts and derivatives. Interest rate and foreign currency exchange risk are managed through the use of forward contracts, swaps and options. The Company s usage of interest rate swaps is discussed in Note 12.

Trading Activities

The Company performs a value at risk analysis of its trading portfolio, which includes over-the-counter and brokerage trading of coal. The use of value at risk allows management to quantify, in dollars, on a daily basis, the price risk inherent in its trading portfolio. The Company s value at risk model is based on the industry standard variance/co-variance approach. This captures exposure related to both option and forward positions. During the year ended December 31, 2006, the low, high, and average values at risk for the Company s coal trading portfolio were $0.7 million, $2.7 million and $1.4 million, respectively. Further discussion of the Company s coal trading assets and liabilities is included in Note 5.

The Company also monitors other types of risk associated with its coal trading activities, including credit, market liquidity and counterparty nonperformance.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Commodity Price Risk

In addition to the derivatives related to trading activities, the Company manages its exposure to price volatility of materials used in production, including diesel fuel and explosives, through various contractual arrangements. As of December 31, 2006, the Company had designated derivative contracts as cash flow hedges for 137.9 million gallons of anticipated fuel usage with contract maturities extending through 2009. The consolidated balance sheet at December 31, 2006 reflects unrealized gains on these cash flow hedges of $12.9 million, which is recorded net of a $5.2 million tax provision in Accumulated other comprehensive loss (see Note 19).

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

Due to the inherent ineffectiveness that occurs when the price of a derivative contract does not perfectly mirror the value of the hedged instrument or transaction, SFAS No. 133 permits a degree of ineffectiveness within a narrowly defined corridor, provided that critical terms of the hedge contract and the hedged activity are sufficiently matched, including maturity and notional amount, and provided that historical and expected future prices are sufficiently correlated. During 2006, the Company did not recognize any impact due to ineffectiveness of hedging contracts that exceeded the defined corridor stipulated in SFAS No. 133. During 2005, the Company recognized approximately $0.1 million of lower operating costs and expenses related to the ineffectiveness of its diesel fuel hedges. Hedge ineffectiveness had no effect on results of operations for the year ended December 31, 2004.

The notional amounts outstanding of 137.9 million gallons included derivative swap contracts for 11.6 million gallons of heating oil and 83.2 million gallons of crude oil and collar contracts for 43.1 million gallons of crude oil that were designated as cash flow hedges of future anticipated diesel fuel purchases as of December 31, 2006. The heating oil contracts are used to hedge fuel purchases in the Company s Eastern mining operations, and the crude oil swaps are used to hedge incremental fuel purchases in the Company s Eastern mining operations with any excess over Eastern requirements allocated to Western operations. The crude collar contracts hedge the Company s remaining expected diesel fuel usage in excess of the crude and heating oil derivative swap contracts in the Eastern and Western mining operations.

In addition to the derivatives related to trading activities and diesel fuel, the Company enters contracts to manage its exposure to the price volatility of explosives. As of December 31, 2006, the Company had derivative contracts designated as cash flow hedges with notional amounts outstanding totaling 5.7 million MMBtu of natural gas, with maturities extending through May 2009. The consolidated balance sheet as of December 31, 2006, reflects unrealized losses on these cash flow hedges of $6.6 million, which is recorded net of a $2.6 million tax benefit in Accumulated other comprehensive loss (see Note 19). The Company s hedge of explosives with natural gas is perfectly effective by design since the contractual purchase of explosives is fixed to the previous month s closing price for natural gas, which occurs in a constant ratio of MMBtu per ton in the manufacture of explosives, plus a fixed surcharge.

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Credit Risk

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

When appropriate, the Company has taken steps to reduce the Company s credit exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk, as determined by the Company s credit management function, of failure to perform under their contractual obligations. These steps include obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for the Company s benefit to fund payment for coal under existing coal supply agreements.

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

Foreign Currency Risk

The Company utilizes currency forwards to hedge currency risk associated with anticipated Australian dollar expenditures. As of December 31, 2006, the Company had forward contracts designated as cash flow hedges with notional amounts outstanding totaling approximately A$1.35 billion, with maturities extending through 2010. The consolidated balance sheet as of December 31, 2006, reflects unrealized gains on the cash flow hedges of $64.1 million, which is recorded net of a $25.6 million tax benefit in Accumulated other comprehensive loss (see Note 19).

Employees

As of December 31, 2006, the Company had approximately 9,200 employees. As of December 31, 2006, approximately 40% of the Company s hourly employees were represented by organized labor unions and generated 14% of the 2006 coal production. Relations with its employees and, where applicable, organized labor are important to the Company s success.

United States Labor Relations

The United Mine Workers of America (UMWA) represented approximately 26% of the Company s subsidiaries hourly employees, who generated 11% of the Company s domestic production during the year ended December 31, 2006. An additional 5% of the hourly employees are represented by labor unions other than the UMWA. These employees generated 1% of the Company s domestic production during the year ended December 31, 2006. Hourly workers at the Company s mine in Arizona are represented by the UMWA under the Western Surface Agreement of 2000, which is effective through September 1, 2007. The Company s union workforce east of the Mississippi River is primarily represented by the UMWA. The UMWA-represented workers at one of the Company s eastern mines operate under a contract that expires on December 31, 2007. The remainder of the Company s UMWA-represented workers in the east operate under a recently signed, five-year labor agreement expiring December 31, 2011. This contract replaced a contract that had expired on December 31, 2006 and mirrors the 2007 National Bituminous Coal Wage Agreement.

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Australia Labor Relations

The Australian coal mining industry is unionized and the majority of workers employed at the Company s Australian Mining Operations are members of trade unions. The Construction Forestry Mining and Energy Union represents the Company s hourly production employees. As of December 31, 2006, the Company s Australian hourly employees were approximately 9% of its hourly workforce and generated 2% of its total production in the year then ended. The labor agreement at the Wilkie Creek Mine was renewed in June 2006 and that agreement expires in June 2009. The North Goonyella Mine operates under an agreement due to expire in 2008, and the Metropolitan Mine operates under an agreement that expires in June 2007.

(3) Resource Management and Other Commercial Events

During 2006, the Company sold non-strategic coal reserves and surface lands located in Kentucky and West Virginia for proceeds of $75.3 million and recognized a gain of $58.9 million. In June 2006, the Company exchanged with the Bureau of Land Management approximately 63 million tons of leased coal reserves at its Caballo mining operation for approximately 46 million tons of coal reserves contiguous with its North Antelope Rochelle mining operation. Based on the fair value of the coal reserves exchanged, the Company recognized a gain on assets exchanged totaling $39.2 million. This non-cash addition is not included in Additions to property, plant, equipment and mine development in the consolidated statement of cash flows. The gains from these transactions are included in Net gain on disposal or exchange of assets in the consolidated statements of operations.

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

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

In the third quarter of 2005, the Company exchanged certain idle steam coal reserves for steam and metallurgical coal reserves as part of a contractual dispute settlement. Under the settlement, the Company received $10.0 million in cash, a new coal supply agreement that partially replaced the disputed coal supply agreement, and exchanged the idle steam coal reserves. As a result of the final settlement and based on the fair values of the items exchanged in the overall settlement transaction, the Company recorded net contract losses of $4.0 million and a gain on assets exchanged of $37.4 million. The fair value of assets exchanged exceeded the book value by $33.4 million and this non-cash addition is not included in Additions to property, plant, equipment and mine development in the consolidated statements of cash flows. The gain from this transaction is included in Net gain on disposal or exchange of assets in the consolidated statements of operations.

(4) Business Combinations

The results of operations for each of the acquired entities discussed below are included in the Company s consolidated statements of operations from the effective date of each acquisition. Had the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

results of operations for Dodge Hill Holding JV, LLC and Carbones del Guasare been included in the Company s results of operations since January 1 of the year acquired, there would have been no material effect on the Company s consolidated statements of operations, financial position or cash flows.

Excel Coal Limited

On July 5, 2006, the Company signed a Merger Implementation Agreement (the Merger Implementation Agreement) to acquire Excel Coal Limited (Excel), an independent coal company, by means of a scheme of arrangement transaction under Australian law (the Transaction). The Merger Implementation Agreement was amended on September 18, 2006, and the Company agreed to pay A$9.50 per share (US$7.16 as of the amendment date) for the outstanding shares of Excel. On September 20, 2006, as part of the amended agreement, the Company acquired 19.99% of the outstanding shares of Excel at A$9.50 per share (the Advance Purchase), resulting in payment of A$408.3 million, or US$307.8 million. In October 2006, the Company acquired the remaining interest in Excel for A$9.50 per share (US$7.07 per share), a total of A$1.63 billion or US$1.21 billion. The total acquisition price, including the Advance Purchase and related costs, was US$1.54 billion in cash plus assumed debt of US$293.0 million, less US$30.0 million of cash acquired in the transaction, and was financed with borrowings under the Company s Senior Unsecured Credit Facility and Senior Notes due 2016 and 2026 as discussed in Note 12. The Excel acquisition includes three operating mines (Wambo Open-Cut Mine, Metropolitan Mine and Chain Valley Mine) and three development-stage mines (North Wambo Underground Mine, Wilpinjong Mine and Millennium Mine), with more than 500 million tons of proven and probable coal reserves. The Company also acquired a 51.0% interest in Excelven Pty Ltd., which owns Transportes Coal-Sea de Venezuela C.A. and a 96.7% interest in Cosila Complejo Siderurgico Del Lago S.A., which owns the Las Carmelitas coal mine development project. The results of operations of Excel are included in the Company s Australian Mining Operations segment from October 2006. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, Business Combinations.

The preliminary purchase accounting allocations related to the acquisition have been recorded in the accompanying consolidated financial statements as of, and for periods subsequent to, October 2006. The final valuation of the net assets acquired is expected to be finalized once third-party appraisals are completed. The following table summarizes the preliminary estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition:

		(Dollars in thousands)
Accounts receivable, net	$	18,700
Inventories		32,044
Other current assets		5,336
Property, plant, equipment and mine development, net		1,897,672
Goodwill		240,667
Current maturities of long-term debt		(17,090)
Accounts payable and accrued expenses		(135,474)
Long-term debt less current maturities		(275,934)
Deferred income taxes, net		(179,026)
Other noncurrent assets and liabilities, net		(60,857)
Minority interests		(18,263)
Total purchase price, net of cash received of $29,995	$	1,507,775

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The preliminary amount allocated to goodwill reflects the excess of the purchase price of acquiring Excel over the net fair value of assets acquired and liabilities assumed and is primarily attributable to customer relations and the Company s ability to acquire and develop coal reserves adjacent to certain operations. The Company is conducting drilling and reserve studies on the acquired properties, the outcome of which will determine the fair value to be allocated to reserve assets. Goodwill will be adjusted upon the final valuation of the net acquired assets and allocated to reporting units. Also, in connection with the Excel acquisition, the Company acquired contract based intangibles consisting solely of coal supply agreement obligations (customer contracts) that were unfavorable based upon current market prices for similar coal in October 2006. These below market obligations were recorded at their preliminarily determined fair value when allocating the purchase price, resulting in a $27.7 million liability. The liability will be amortized as the coal is shipped over an average amortization period of approximately five years.

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

	Year Ended December 31,	
	2006	**2005**
	(Dollars in thousands, except per share data)	
Revenues:		
As reported	$ 5,256,315	$ 4,644,453
Pro forma	5,551,347	4,972,791
Net income:		
As reported	$ 600,697	$ 422,653
Pro forma	568,582	362,884
Basic earnings per share net income:		
As reported	$ 2.28	$ 1.62
Pro forma	2.16	1.39
Diluted earnings per share net income:		
As reported	$ 2.23	$ 1.58
Pro forma	2.11	1.35

RAG Coal International AG

On April 15, 2004, the Company purchased, through two separate agreements, all of the equity interests in three coal operations from RAG Coal International AG. The combined purchase price, including related costs and fees, of $442.2 million was funded from equity and debt offerings. The purchases included two mines in Queensland, Australia that collectively produce 6 to 7 million tons per year of metallurgical coal and the Twentymile Mine in Colorado, which produces 8 to 9 million tons per year of steam coal. The results of operations of the two mines in Queensland, Australia are included in the Company s Australian Mining Operations segment and the results of operations of the Twentymile Mine are included in the Company s Western U.S. Mining Operations segment from the April 15, 2004, purchase date. The acquisition was accounted for as a purchase.

In connection with the acquisition of the assets of the Australian mines and the Twentymile Mine, the Company acquired contract based intangibles consisting solely of coal supply agreement obligations (customer contracts) that were unfavorable based upon current market prices for similar coal as of

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

April 15, 2004. These below market obligations were recorded at fair value as part of the purchase price allocation resulting in a $46.8 million liability, which is amortized as the coal is shipped. As of December 31, 2006, the carrying value of these acquired contract liabilities is $8.1 million and the estimated amortization (reduction to Depreciation, depletion and amortization in the consolidated statements of operations) is $6.5 million, $1.0 million and $0.6 million for the years ending December 31, 2007, 2008, and 2009, respectively.

Dodge Hill Holding JV, LLC

On December 29, 2004, the Company purchased the remaining 55% interest in Dodge Hill Holding JV, LLC for $7.0 million of assumed debt that was repaid immediately upon closing, $2.8 million of cash and contingent earn-out payments based on annual and cumulative EBIT (as defined in the purchase agreement) through 2007. Dodge Hill Holding JV, LLC is located in Kentucky and operates an underground operation which mines approximately 1.5 million tons per year. The acquisition was accounted for as a purchase.

Carbones del Guasare

On December 2, 2004, the Company acquired a 25.5% equity interest in Carbones del Guasare, S.A., from RAG Coal International AG for a net purchase price of $32.5 million. Carbones del Guasare, a joint venture that includes Anglo American plc and a Venezuelan governmental partner, operates the Paso Diablo surface mine in northwestern Venezuela. In 2006, the mine produced approximately 6 million tons of steam coal for electricity generators and steel producers primarily in North America and Europe. The Company accounted for the purchase under the equity method of accounting.

(5) Assets and Liabilities from Coal Trading Activities

The Company s coal trading portfolio included forward and swap contracts as of December 31, 2006 and forward contracts as of December 31, 2005. The fair value of coal trading derivatives and related hedge contracts is set forth below:

	December 31, 2006		December 31, 2005	
	Assets	Liabilities	Assets	Liabilities
	(Dollars in thousands)			
Forward contracts	$ 142,105	$ 120,718	$ 146,596	$ 131,988
Financial swaps	8,268	6,013		
Other				385
Total	$ 150,373	$ 126,731	$ 146,596	$ 132,373

All of the contracts in the Company s trading portfolio as of December 31, 2006 were valued utilizing prices from over-the-counter market sources, adjusted for coal quality and traded transportation differentials.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2006, the estimated future realization of the value of the Company s trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio
2007	41%
2008	39%
2009	15%
2010	5%
	100%

At December 31, 2006, 62% of the Company s credit exposure related to coal trading activities was with investment grade counterparties and 38% was with non-investment grade counterparties. The Company s coal trading operations traded 79.1 million tons, 36.2 million tons and 33.4 million tons for the years ended December 31, 2006, 2005 and 2004, respectively.

(6) Accounts Receivable Securitization

The Company has established an accounts receivable securitization program through its wholly-owned, bankruptcy-remote subsidiary (Seller). Under the program, the Company contributes undivided interests in a pool of eligible trade receivables to the Seller, which then sells, without recourse, to a multi-seller, asset-backed commercial paper conduit (Conduit). Purchases by the Conduit are financed with the sale of highly rated commercial paper. The Company utilizes proceeds from the sale of its accounts receivable as an alternative to other forms of debt, effectively reducing its overall borrowing costs. The funding cost of the securitization program was $1.9 million, $2.5 million and $1.7 million for the years ended December 31, 2006, 2005 and 2004, respectively. The securitization program is currently scheduled to expire in September 2009.

The securitization transactions have been recorded as sales, with those accounts receivable sold to the Conduit removed from the consolidated balance sheets. The amount of undivided interests in accounts receivable sold to the Conduit was $219.2 million and $225.0 million as of December 31, 2006 and 2005, respectively.

The Seller is a separate legal entity whose assets are available first and foremost to satisfy the claims of its creditors. Eligible receivables, as defined in the securitization agreement, consist of trade receivables from most of the Company s domestic subsidiaries, and are reduced for certain items such as past due balances and concentration limits. Of the eligible pool of receivables contributed to the Seller, undivided interests in only a portion of the pool are sold to the Conduit. The Company (the Seller) continues to own $166.4 million of receivables as of December 31, 2006, that represents collateral supporting the securitization program. The Seller s interest in these receivables is subordinate to the Conduit s interest in the event of default under the securitization agreement. If the Company defaulted under the securitization agreement or if its pool of eligible trade receivables decreased significantly, the Company could be prohibited from selling any additional receivables in the future under the agreement.

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(7) Earnings per Share

A reconciliation of weighted-average shares outstanding follows:

	Year Ended December 31,		
	2006	2005	2004
Weighted-average shares outstanding basic	263,419,344	261,519,424	248,732,744
Dilutive impact of stock options, restricted stock units and performance units	5,746,661	6,494,052	6,079,888
Weighted-average shares outstanding diluted	269,166,005	268,013,476	254,812,632

For the year ended December 31, 2004, options for three thousand shares were excluded from the diluted earnings per share calculations for the Company s common stock because they were anti-dilutive.

(8) Inventories

Inventories consisted of the following:

	December 31,	
	2006	2005
	(Dollars in thousands)	
Materials and supplies	$ 85,242	$ 65,942
Raw coal	42,693	14,033
Saleable coal	87,449	64,274
Advance stripping		245,522
Total	$ 215,384	$ 389,771

Due to an accounting change that was effective on January 1, 2006, advance stripping costs are no longer a separate component of inventory (see Note 1).

(9) Leases

The Company leases equipment and facilities under various noncancelable lease agreements. Certain lease agreements require the maintenance of specified ratios and contain restrictive covenants which limit indebtedness, subsidiary dividends, investments, asset sales and other Company actions. Rental expense under operating leases was $106.9 million, $108.6 million and $108.1 million for the years ended December 31, 2006, 2005 and 2004, respectively. The net book value of property, plant, equipment and mine development assets under capital leases was $56.7 million and $1.5 million as of December 31, 2006 and 2005, respectively, related primarily to the leasing of mining equipment.

The Company also leases coal reserves under agreements that require royalties to be paid as the coal is mined. Certain agreements also require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Total royalty expense was $336.8 million, $288.1 million and $233.9 million for the years ended December 31, 2006, 2005 and 2004, respectively.

A substantial amount of the coal mined by the Company is produced from mineral reserves leased from the owner. One of the major lessors is the U.S. government, from which the Company leases substantially all of the coal it mines in Wyoming and Colorado under terms set by Congress and administered by the U.S. Bureau of Land Management. These leases are generally for an initial term of ten years but may be extended by diligent development and mining of the reserve until all economically recoverable reserves are depleted. The Company has met the diligent development requirements for substantially all of these federal leases either directly through production or by including the lease as a

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PEABODY ENERGY CORPORATION
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part of a logical mining unit with other leases upon which development has occurred. Annual production on these federal leases must total at least 1.0% of the original amount of coal in the entire logical mining unit. In addition, royalties are payable monthly at a rate of 12.5% of the gross realization from the sale of the coal mined using surface mining methods and at a rate of 8.0% of the gross realization for coal produced using underground mining methods. The Company also leases coal reserves in Arizona from The Navajo Nation and the Hopi Tribe under leases that are administered by the U.S. Department of the Interior. These leases expire upon exhaustion of the leased reserves or upon the permanent ceasing of all mining activities on the related reserves as a whole. The royalty rates are also generally based upon a percentage of the gross realization from the sale of coal. These rates are subject to redetermination every ten years under the terms of the leases. The remainder of the leased coal is generally leased from state governments, land holding companies and various individuals. The duration of these leases varies greatly. Typically, the lease terms are automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

Future minimum lease and royalty payments as of December 31, 2006, are as follows:

Year Ended December 31,	**Capital Leases**	**Operating Leases**	**Coal Reserves**
		(Dollars in thousands)	
2007	$ 11,335	$ 102,256	$ 216,996
2008	9,986	86,358	201,839
2009	11,820	65,906	142,568
2010	7,843	56,666	14,664
2011	7,843	44,720	10,795
2012 and thereafter	23,428	168,076	46,611
Total minimum lease payments	$ 72,255	$ 523,982	$ 633,473
Less interest	15,548		
Present value of minimum capital lease payments	$ 56,707		

During 2002, the Company entered into a transaction with Penn Virginia Resource Partners, L.P. (PVR) whereby the Company sold 120 million tons of coal reserves in exchange for $72.5 million in cash and 2.76 million units, or 15%, of the PVR master limited partnership. The Company s subsidiaries leased back the coal and pay royalties as the coal is mined. No gain or loss was recorded at the inception of this transaction. In 2005 and 2004, the Company sold 0.838 million and 0.775 million, respectively, of the PVR units received in the original transaction. As of December 31, 2006 and 2005, the Company had no remaining ownership in PVR. The PVR unit sales were accounted for under SFAS No. 66, Sales of Real Estate , and gains of $31.1 million and $15.8 million were recognized in the years ended December 31, 2005 and 2004, respectively. The remaining deferred gain from the sales of the reserves and units of $13.3 million at December 31, 2006 is intended to provide for the Company s potential exposure to loss resulting from its continuing involvement in the properties and will be amortized over the minimum term of the leases.

As of December 31, 2006, certain of the Company s lease obligations were secured by outstanding surety bonds and letters of credit totaling $104.2 million.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consisted of the following:

	December 31,	
	2006	2005
	(Dollars in thousands)	
Trade accounts payable	$ 462,553	$ 348,320
Accrued taxes other than income	128,336	111,997
Accrued payroll and related benefits	130,306	110,675
Accrued health care	88,472	78,523
Workers compensation obligations	30,966	34,312
Other accrued benefits	11,647	21,939
Accrued royalties	53,260	50,344
Accrued environmental	14,390	23,619
Income taxes payable Australia	94,692	23,409
Accrued interest	38,189	21,260
Other accrued expenses	92,232	43,567
Total accounts payable and accrued expenses	$ 1,145,043	$ 867,965

(11) Income Taxes

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

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands)		
U.S.	$ 292,079	$ 253,329	$ 118,076
Non U.S.	238,883	172,756	34,995
Total	$ 530,962	$ 426,085	$ 153,071

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands)		
Current:			
U.S. federal	$ 6,585	$	$ 655
Non U.S.	67,565	25,622	4,533
State	405	300	300
Total current	74,555	25,922	5,488
Deferred:			
U.S. federal	(159,536)	(18,475)	(33,275)
Non U.S.	4,094	22,997	(328)
State	(628)	(29,484)	1,678
Total deferred	(156,070)	(24,962)	(31,925)
Total provision (benefit)	$ (81,515)	$ 960	$ (26,437)

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

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands)		
Federal statutory rate	$ 185,837	$ 149,130	$ 53,575
Depletion	(64,964)	(59,412)	(43,488)
Foreign earnings rate differential	(16,649)	(12,279)	(8,043)
State income taxes, net of U.S. federal tax benefit	6,160	(29,288)	1,872
Deemed liquidation of subsidiary		(314,071)	
Changes in valuation allowance	(165,481)	216,908	(25,863)
Changes in tax reserves	(28,658)	44,968	
Other, net	2,240	5,004	(4,490)
Total provision (benefit)	$ (81,515)	$ 960	$ (26,437)

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31,	
	2006	2005
	(Dollars in thousands)	
Deferred tax assets:		
Postretirement benefit obligations	$ 630,124	$ 410,905
Tax credits and loss carryforwards	610,333	579,549
Accrued long-term workers compensation liabilities	103,353	101,346
Additional minimum pension liability		46,931
Accrued reclamation and mine closing liabilities	56,066	46,139
Intangible tax asset and purchased contract rights	60,956	35,405
Obligation to industry fund	11,197	12,112
Others	85,703	71,311
Total gross deferred tax assets	1,557,732	1,303,698
Deferred tax liabilities:		
Property, plant, equipment and mine development, leased coal interests and advance royalties, principally due to differences in depreciation, depletion and asset writedowns	1,423,693	1,168,470
Inventory		77,824
Others		1,021
Total gross deferred tax liabilities	1,423,693	1,247,315
Valuation allowance	(222,285)	(385,844)
Net deferred tax liability	$ (88,246)	$ (329,461)
Deferred taxes consisted of the following:		
Current deferred income taxes	$ 106,967	$ 9,027
Noncurrent deferred income taxes	(195,213)	(338,488)
Net deferred tax liability	$ (88,246)	$ (329,461)

The Company s deferred tax assets included alternative minimum tax (AMT) credits of $32.8 million and $26.2 million, U.S. net operating loss (NOL) carryforwards of $538.0 million and $553.1 million and foreign NOL and capital loss carryforwards of $39.6 million and $0.2 million as of December 31, 2006 and 2005, respectively. The AMT credits and foreign NOL and capital loss carryforwards have no expiration date and the U.S. NOL carryforwards begin to expire in the year 2019. Utilization of these AMT credits and U.S. NOL carryforwards is subject to various limitations because of previous changes in ownership (as defined in the Internal Revenue Code) of the Company, and ultimate realization could be negatively impacted by market conditions and other variables not known or anticipated at this time. The AMT credits and U.S. NOL carryforwards are offset by a valuation allowance of $215.7 million. The valuation allowance was reduced by $169.9 million and $25.9 million for the years ended December 31, 2006 and 2004, respectively. The valuation allowance was increased by $216.9 million for the year ended December 31, 2005, to correspond with an increase in available NOLs. The Company evaluated and assessed the expected near-term utilization of NOLs, book and taxable income trends, available tax strategies and the overall deferred tax position to determine the amount and timing of valuation allowance adjustments. The foreign capital loss carryforwards and a deferred tax asset related to

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

certain coal reserves are offset by a valuation allowance of $6.6 million. The valuation allowance was increased by $6.3 million for the year ended December 31, 2006.

During 2005, the Company completed a comprehensive and strategic internal corporate restructuring project. This restructuring focused on realigning the Company s subsidiary ownership on a geographic and functional basis and facilitated the consolidation of assets in a tax-efficient manner, better positioning the Company to execute future strategic transactions. One of the indirect consequences of the internal corporate restructuring was a deduction for a deemed liquidation of a subsidiary for tax purposes, which, as a result, increased the Company s NOLs by $1.0 billion.

The Company establishes reserves for tax contingencies when, despite the belief that the Company s 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. The Company s effective tax rate includes the impact of tax contingency reserves and changes to the reserves, including related interest, as considered appropriate by management. The Company establishes the reserves based upon management s assessment of exposure associated with permanent tax differences (e.g., tax depletion expense). The tax contingency reserve was decreased for the year ended December 31, 2006, by $28.7 million reflecting the reduction in exposure due to the completion of federal and state audits. The tax contingency reserve was increased by $45.0 million for the tax year ended December 31, 2005.

The total amount of undistributed earnings of foreign subsidiaries for income tax purposes was approximately $318.9 million and $156.0 million at December 31, 2006 and 2005, respectively. The Company has not provided deferred taxes on foreign earnings because such earnings were intended to be indefinitely reinvested outside the United States. Should the Company repatriate all of these earnings, a one-time income tax charge to the Company s consolidated results of operations of up to $110 million could occur.

The Company made U.S. Federal tax payments totaling $3.9 million and $1.4 million for the years ended December 31, 2006 and 2004, respectively. The Company made no U.S. Federal tax payments for the year ended December 31, 2005. The Company paid state and local income taxes totaling $0.5 million, $0.3 million and $0.3 million for the years ended December 31, 2006, 2005 and 2004, respectively. The Company made non-U.S. tax payments totaling $23.1 million, $2.8 million and $6.3 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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PEABODY ENERGY CORPORATION
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(12) Long-Term Debt

The Company s total indebtedness as of December 31, 2006 and 2005, consisted of the following:

	December 31, 2006	December 31, 2005
	(Dollars in thousands)	
Term Loan under Senior Unsecured Credit Facility	$ 547,000	$
Term Loan under Senior Secured Credit Facility		442,500
Convertible Junior Subordinated Debentures due 2066	732,500	
7.375% Senior Notes due 2016	650,000	
6.875% Senior Notes due 2013	650,000	650,000
7.875% Senior Notes due 2026	246,897	
5.875% Senior Notes due 2016	231,845	239,525
5.0% Subordinated Note	59,504	66,693
6.84% Series C Bonds due 2016	43,000	
6.34% Series B Bonds due 2014	21,000	
6.84% Series A Bonds due 2014	10,000	
Capital lease obligations	56,707	1,529
Fair value of interest rate swaps	(13,784)	(8,879)
Other	29,157	14,138
Total	$ 3,263,826	$ 1,405,506

Senior Unsecured Credit Facility

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

The Revolver replaced the Company s previous $900.0 million revolving credit facility, and the increased capacity is intended to accommodate working capital needs, letters of credit, the funding of capital expenditures and other general corporate purposes. The Revolver also includes a $50.0 million sub-facility available for same-day swingline loan borrowings. In September 2006, the Company borrowed $312.0 million under the Revolver in conjunction with the Excel acquisition and repaid this $312.0 million outstanding balance in December 2006 with net proceeds from the Debentures. As of December 31, 2006, the remaining available borrowing capacity under the Revolver was $1.29 billion.

The Term Loan Facility consisted of an unsecured $440.0 million portion (the Term Loan), which was drawn at closing to replace the previous term loan ($437.5 million balance at time of replacement; $442.5 million at December 31, 2005) issued under the Senior Secured Credit Facility. The Term Loan Facility also includes a Delayed Draw Term Loan Sub-Facility of up to $510.0 million, which was fully drawn in October 2006 in connection with the Excel acquisition. In December 2006, $403.0 million of the outstanding balance of the Term Loan Facility ($950.0 million was outstanding at time of repayment) was repaid with the net proceeds from the Debentures. In conjunction with the establishment of the Senior Unsecured Credit Facility, the Company incurred $8.6 million in financing costs, of which

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$5.6 million related to the Revolver and $3.0 million related to the Term Loan. These debt issuance costs are being amortized to interest expense over five years, the term of the Senior Unsecured Credit Facility.

Loans under the facility are available to the Company in U.S. dollars, with a sub-facility under the Revolver available in Australian dollars, pounds sterling and Euros. Letters of credit under the Revolver are available to the Company in U.S. dollars with a sub-facility available in Australian dollars, pounds sterling and Euros. The interest rate payable on the Revolver and the Term Loan under the Senior Unsecured Credit Facility is LIBOR plus 1.0% with step-downs to LIBOR plus 0.50% based on improvement in the leverage ratio, as defined in the Agreement. The rate applicable to the Term Loan Facility was 6.35% at December 31, 2006.

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

Convertible Junior Subordinated Debentures

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

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

The Debentures are convertible at any time on or prior to December 15, 2036 if any of the following conditions occur: (i) the Company s closing common stock price exceeds 140% of the then applicable conversion price for the Debentures (currently $86.73 per share) for at least 20 of the final 30 trading days in any quarter; (ii) a notice of redemption is issued with respect to the Debentures; (iii) a change of control, as defined in the indenture governing the Debentures; (iv) satisfaction of certain trading price conditions; and (v) other specified corporate transactions described in the indenture governing the Debentures. In addition, the Debentures are convertible at any time after December 15, 2036 to December 15, 2041, the scheduled maturity date. In the case of conversion following a notice of redemption or upon a non-stock change of control, as defined in the indenture governing the Debentures, holders may convert their Debentures into cash in the amount of the principal amount of their Debentures and shares of the Company s common stock for any conversion value in excess of the principal amount. In all other conversion circumstances, holders will receive perpetual preferred stock (see Note 17) with a liquidation preference equal to the principal amount of their Debentures, and any conversion value in excess of the principal amount will be settled with the Company s common stock. The consideration delivered upon conversion will be based upon an initial conversion rate of 16.1421 shares of common stock per $1,000 principal amount of Debentures, subject to adjustment. This conversion rate represents an

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initial conversion price of approximately $61.95 per share, a 40% premium over the closing stock price of $44.25 on December 14, 2006, the date of the pricing of the offering of the Debentures.

The Debentures are not subject to redemption prior to December 20, 2011. Between December 20, 2011 and December 19, 2036 the Company may redeem the Debentures, in whole or in part, if for at least 20 out of the 30 consecutive trading days immediately prior to the date on which notice of redemption is given, the Company s closing common stock price has exceeded 130% of the then applicable conversion price for the Debentures. On or after December 20, 2036, whether or not the redemption condition is satisfied, the Company may redeem the Debentures, in whole or in part. The Company may not redeem any Debentures unless (i) all accrued and unpaid interest on the Debentures has been paid in full on or prior to the redemption date and (ii) if any perpetual preferred stock is outstanding, the Company has first given notice to redeem the perpetual preferred stock in the same proportion as the redemption of the Debentures. Any redemption of the Debentures will be at a cash redemption price of 100% of the principal amount of the Debentures to be redeemed, plus accrued and unpaid interest to the date of redemption.

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

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

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

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

On October 12, 2006, the Company completed a $650 million offering of 7.375% 10-year Senior Notes due 2016 and $250 million of 7.875% 20-year Senior Notes due 2026. The notes are general unsecured obligations of the Company and rank senior in right of payment to any subordinated indebtedness of the Company; equally in right of payment with any senior indebtedness of the Company; effectively junior in right of payment to the Company s existing and future secured indebtedness, to the

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extent of the value of the collateral securing that indebtedness; and effectively junior to all the indebtedness and other liabilities of the Company s subsidiaries that do not guarantee the notes. Interest payments are scheduled to occur on May 1 and November 1 of each year, commencing on May 1, 2007.

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

6.875% Senior Notes Due March 2013

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

5.875% Senior Notes Due March 2016

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

5.0% Subordinated Note

The 5.0% Subordinated Note is recorded net of discount with interest and principal payable each March 1. The Company repaid $10.0 million of principal in March 2006, with the remaining $60.0 million due March 1, 2007. The 5.0% Subordinated Note is expressly subordinated in right of payment to all prior indebtedness as disclosed above.

Series Bonds

As of December 31, 2006, the Company had $74.0 million in Series Bonds outstanding, which were assumed as part of the Excel acquisition. The 6.84% Series A Bonds have a balloon maturity in December 2014. The 6.34% Series B Bonds mature in December 2014 and are payable in installments beginning

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Interest Rate Swaps

Prior to completion of the Senior Unsecured Credit Facility, the Company had two $400.0 million interest rate swaps. A $400.0 million notional amount floating-to-fixed interest rate swap was designated as a hedge of changes in expected cash flows on the previous term loan under the Senior Secured Credit Facility. Under this swap, the Company paid a fixed rate of 6.764% and received a floating rate of LIBOR plus 2.5% that reset each March 15, June 15, September 15 and December 15 based upon the three-month LIBOR rate. A $400.0 million notional amount fixed-to-floating interest rate swap was designated as a hedge of the changes in the fair value of the 6.875% Senior Notes due 2013. Under this swap, the Company paid a floating rate of LIBOR plus 1.97% that reset each March 15, June 15, September 15 and December 15 based upon the three-month LIBOR rate and received a fixed rate of 6.875%.

In conjunction with the completion of the new Senior Unsecured Credit Facility, the $400.0 million notional amount floating-to-fixed interest rate swap was terminated and resulted in payment to the Company of $5.2 million. The Company recorded the $5.2 million fair value of the swap in Accumulated other comprehensive loss on the consolidated balance sheet and will amortize this amount to interest expense over the remaining term of the forecasted interest payments initially hedged. The Company then entered into a $120.0 million notional amount floating-to-fixed interest rate swap with a fixed rate of 6.25% and a floating rate of LIBOR plus 1.0%. This interest rate swap was designated as a hedge of the variable interest payments on the Term Loan under the new Senior Unsecured Credit Facility.

The Company also terminated $280.0 million of its $400.0 million notional amount fixed-to-floating interest rate swap designated as a hedge of the changes in fair value of the 6.875% Senior Notes due 2013. Reducing the notional amount of the interest rate swap to $120.0 million resulted in payment of $5.2 million to the counterparty. Reduction of the notional amount of the swap did not affect its floating and fixed rates. The $5.2 million of fair value associated with the termination of the $280.0 million portion of the swap was recorded as an adjustment to the carrying value of long-term debt and will be amortized to interest expense through maturity of the 6.875% Senior Notes due 2013.

Because the critical terms of the swaps and the respective debt instruments they hedge coincide, there was no hedge ineffectiveness recognized in the consolidated statements of operations during the years ended December 31, 2006 and 2005. At December 31, 2006 there was an unrealized loss related to the cash flow hedge of $2.5 million and at December 31, 2005 there was an unrealized gain related to the cash flow hedge of $2.3 million. As of December 31, 2006 and 2005, net unrealized loss on the fair value hedges discussed above was $13.8 million and $8.9 million, respectively, which is reflected as an adjustment to the carrying value of the Senior Notes (see table above).

Capital Lease Obligations and Other

Capital lease obligations include obligations assumed from the Excel acquisition, primarily for mining equipment (see Note 9 for additional information on the Company s capital lease obligations).

Other long-term debt, which consists principally of notes payable, is due in installments through 2016. The weighted-average effective interest rate of this debt was 3.98% as of December 31, 2006.

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The aggregate amounts of long-term debt maturities subsequent to December 31, 2006, including capital lease obligations, were as follows:

Year of Maturity		(Dollars in thousands)
2007	$	95,757
2008		47,078
2009		40,504
2010		37,051
2011		445,842
2012 and thereafter		2,597,594
Total	$	3,263,826

Interest paid on long-term debt was $114.6 million, $94.2 million and $87.4 million for the years ended December 31, 2006, 2005 and 2004, respectively. The Company paid interest expense of $3.3 million on the Revolver in 2006 and no interest was paid on the Revolver in 2005 or 2004.

Early Debt Extinguishment Costs

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

In 2004, the Company recorded a net charge for early debt extinguishment of $1.8 million. In connection with the refinancing of the Senior Secured Credit Facility on October 27, 2004, the Company incurred a non-cash charge of $2.4 million to write-off unamortized debt issuance costs related to the term loan. In connection with the July 2004 repurchase of $10.5 million of 5.875% Senior Notes due March 2016, the Company realized a gain of $0.6 million.

Shelf Registration Statement

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

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(13) Asset Retirement Obligations

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

	December 31,	
	2006	2005
	(Dollars in thousands)	
Balance at beginning of year	$ 399,203	$ 396,022
Liabilities incurred or acquired	18,573	24,101
Liabilities settled or disposed	(40,621)	(40,341)
Accretion expense	29,480	24,095
Revisions to estimate	16,396	(4,674)
Balance at end of year	$ 423,031	$ 399,203

As of December 31, 2006, asset retirement obligations of $423.0 million consisted of $354.0 million related to locations with active mining operations and $69.0 million related to locations that are closed or inactive. As of December 31, 2005, asset retirement obligations of $399.2 million consisted of $340.7 million related to locations with active mining operations and $58.5 million related to locations that are closed or inactive. The credit-adjusted risk-free interest rates were 6.16% and 5.81% at January 1, 2006 and 2005, respectively.

In 2006, the Company assumed $7.2 million of asset retirement obligations with the Excel acquisition (see Note 4) and incurred additional obligations related to the opening of new mine pits. For the year ended December 31, 2005, the Company recorded a $9.2 million reduction in its asset retirement obligations associated with the disposal of non-strategic properties and the assumption of the related reclamation liabilities by the purchaser. Also during 2005, the Company recorded $21.6 million for asset retirement obligations associated with assets acquired from Lexington Coal Company (see Note 3).

As of December 31, 2006 and 2005, the Company had $441.5 million and $323.6 million, respectively, in surety bonds outstanding to secure reclamation obligations or activities. The amount of reclamation self-bonding in certain states in which the Company qualifies was $685.2 million and $671.8 million as of December 31, 2006 and 2005, respectively. Additionally, the Company had $4.1 million and $0.1 million of letters of credit in support of reclamation obligations or activities as of December 31, 2006 and 2005, respectively.

(14) Workers Compensation Obligations

Certain subsidiaries of the Company are subject to the Federal Coal Mine Health and Safety Act of 1969 and the related workers compensation laws in the states in which they operate. These laws require the subsidiaries to pay benefits for occupational disease resulting from coal workers pneumoconiosis (occupational disease). Changes to the federal regulations became effective in August 2001, and the revised regulations could ultimately result in higher costs, although experience to date has not resulted in higher claims costs. Provisions for occupational disease costs are based on determinations by independent actuaries or claims administrators.

The Company provides income replacement and medical treatment for work related traumatic injury claims as required by applicable state law. Provisions for estimated claims incurred are recorded based on estimated loss rates applied to payroll and claim reserves determined by independent actuaries or claims administrators. Certain subsidiaries of the Company are required to contribute to state workers compensation funds for second injury and other costs incurred by the state fund based on a payroll-based assessment by the applicable state. Provisions are recorded based on the payroll-based assessment criteria.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The workers compensation provision consisted of the following components:

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands)		
Service cost	$ 4,175	$ 4,491	$ 4,346
Interest cost	10,327	10,425	11,568
Net amortization	(1,894)	(1,213)	742
Total occupational disease	12,608	13,703	16,656
Traumatic injury claims	20,743	25,610	27,141
State assessment taxes	10,676	16,820	15,365
Total provision	$ 44,027	$ 56,133	$ 59,162

The weighted-average assumptions used to determine the workers compensation provision were as follows:

	Year Ended December 31,		
	2006	2005	2004
Discount rate	5.90%	6.10%	6.40%
Inflation rate	3.50%	3.50%	3.50%

Workers compensation obligations consist of amounts accrued for loss sensitive insurance premiums, uninsured claims and related taxes and assessments under black lung and traumatic injury workers compensation programs.

The workers compensation obligations consisted of the following:

	December 31,	
	2006	2005
	(Dollars in thousands)	
Occupational disease costs	$ 187,477	$ 190,347
Traumatic injury claims	76,896	81,539
Total obligations	264,373	271,886
Less current portion (included in Accounts payable and accrued expenses)	(30,966)	(34,312)
Noncurrent obligations (included in Workers compensation obligations)	$ 233,407	$ 237,574

As a result of the adoption of SFAS No. 158 on December 31, 2006, the accrued workers compensation liability on the consolidated balance sheet at December 31, 2006 reflects the accumulated obligation less any portion that is currently funded. The adoption of SFAS No. 158 decreased liabilities by $4.6 million and Accumulated other comprehensive loss by $2.7 million at December 31, 2006.

As of December 31, 2006 and 2005, the Company had $188.5 million and $163.8 million, respectively, in surety bonds and letters of credit outstanding to secure workers compensation obligations.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The reconciliation of changes in the occupational disease liability benefit obligation were as follows:

	December 31,	
	2006	2005
	(Dollars in thousands)	
Change in benefit obligation:		
Beginning of year obligation	$ 187,907	$ 199,346
Service cost	4,175	4,491
Interest cost	10,327	10,425
Net actuarial gain	(6,122)	(16,071)
Benefit and administrative payments	(8,810)	(10,284)
Net obligation at end of year	187,477	187,907
Change in plan assets:		
Fair value of plan assets at beginning of period		
Employer contributions	8,810	10,284
Benefits paid	(8,810)	(10,284)
Fair value of plan assets at end of period		
Funded status at end of period	(187,477)	(187,907)
Unrecognized actuarial gain		(2,440)
Accrued cost	$ (187,477)	$ (190,347)

The liability for occupational disease claims represents the actuarially-determined present value of known claims and an estimate of future claims that will be awarded to current and former employees. The liability for occupational disease claims was based on a discount rate of 6.0% and 5.9% at December 31, 2006 and 2005, respectively. Traumatic injury workers compensation obligations are estimated from both case reserves and actuarial determinations of historical trends, discounted at 5.9% and 6.1% for the years ended December 31, 2006 and 2005, respectively.

Federal Black Lung Excise Tax Refund Claims

In addition to the obligations discussed above, certain subsidiaries of the Company are required to pay black lung excise taxes to the Federal Black Lung Trust Fund (the Trust Fund). The Trust Fund pays occupational disease benefits to entitled former miners who worked prior to July 1, 1973. Excise taxes are based on the selling price of coal, up to a maximum of $1.10 per ton for underground mines and $0.55 per ton for surface mines. The Company had a receivable for excise tax refunds of $19.4 million as of December 31, 2006 and 2005. In a January 2007 decision, a federal appellate court ruled that the Company is also entitled to collect interest on the $19.4 million refund from the federal government.

(15) Pension and Savings Plans

One of the Company s subsidiaries, Peabody Investments Corp., sponsors a defined benefit pension plan covering certain U.S. salaried employees and eligible hourly employees at certain Peabody Investments Corp. subsidiaries (the Peabody Plan). A Peabody Investments Corp. subsidiary also has a defined benefit pension plan covering eligible employees who are represented by the UMWA under the Western Surface Agreement of 2000 (the Western Plan).

Peabody Investments Corp. also sponsors an unfunded supplemental retirement plan to provide senior management with benefits in excess of limits under the federal tax law.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Annual contributions to the plans are made as determined by consulting actuaries based upon the Employee Retirement Income Security Act of 1974 minimum funding standard. In May 1998, the Company entered into an agreement with the Pension Benefit Guaranty Corporation which requires the Company to maintain certain minimum funding requirements. Beginning on January 1, 2008, new minimum funding standards will be required by the Pension Protection Act of 2006. Assets of the plans are primarily invested in various marketable securities, including U.S. government bonds, corporate obligations and listed stocks.

Net periodic pension costs included the following components:

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands)		
Service cost for benefits earned	$ 12,234	$ 11,853	$ 12,275
Interest cost on projected benefit obligation	46,034	45,499	43,658
Expected return on plan assets	(54,587)	(52,812)	(49,813)
Other amortizations and deferrals	22,653	24,588	22,366
Net periodic pension costs	26,334	29,128	28,486
Curtailment charges		9,527	
Total net periodic pension costs	$ 26,334	$ 38,655	$ 28,486

The Company amortizes actuarial gains and losses using a 5% corridor with a five-year amortization period. The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive income (loss) into net periodic pension costs during the year ended December 31, 2007 are $19.2 million and less than $0.1 million, respectively.

The 2005 curtailment loss resulted from the termination of operations at two of the three operating mines that participate in the Western Plan during 2005. The loss is actuarially determined and consists of an increase in the actuarial liability, the accelerated recognition of previously unamortized prior service cost and contractual termination benefits under the Western Plan resulting from the termination of operations.

During the period ended March 31, 1999, the Company made an amendment to phase out the Peabody Plan. Effective January 1, 2001, certain employees no longer accrue future service under the plan while other employees accrue reduced service under the plan based on their age and years of service as of December 31, 2000. For plan benefit calculation purposes, employee earnings are also frozen as of December 31, 2000. The Company has adopted an enhanced savings plan contribution structure in lieu of benefits formerly accrued under the defined benefit pension plan.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following summarizes the change in benefit obligation, change in plan assets and funded status of the Company s plans:

	December 31,	
	2006	2005
	(Dollars in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of period	$ 801,818	$ 759,283
Service cost	12,234	11,853
Interest cost	46,034	45,499
Plan amendments		(225)
Curtailments		(1,309)
Special termination benefits		7,896
Benefits paid	(40,323)	(38,315)
Actuarial loss	13,037	17,136
Projected benefit obligation at end of period	832,800	801,818
Change in plan assets:		
Fair value of plan assets at beginning of period	654,023	642,400
Actual return on plan assets	84,326	42,707
Employer contributions	6,146	7,231
Benefits paid	(40,323)	(38,315)
Fair value of plan assets at end of period	704,172	654,023
Funded status at end of year	(128,628)	(147,795)
Unrecognized actuarial loss		141,517
Unrecognized prior service cost		346
Accrued pension liability	$ (128,628)	$ (5,932)
Amounts recognized in the consolidated balance sheets:		
Accrued benefit liability	$ (128,628)	$ (125,622)
Intangible asset		2,362
Additional minimum pension liability, included in other comprehensive income		117,328
Net amount recognized	$ (128,628)	$ (5,932)

Prior to being amended by SFAS No. 158, the provisions of SFAS No. 87 required the recognition of an additional minimum liability and related intangible asset to the extent that accumulated benefits exceed plan assets. As of December 31, 2005, the Company had recorded $117.3 million to reflect the Company s minimum liability. SFAS No. 158, which was adopted on December 31, 2006, eliminated the need to recognize an additional minimum pension liability and related intangible asset.

The current portion of the Company s pension liability as reflected in Accounts payable and accrued expenses at December 31, 2006 and 2005 was $1.3 million and $7.9 million, respectively. The noncurrent portion of the Company s pension liability as reflected in Other noncurrent liabilities at December 31, 2006 and 2005 was $127.3 million and $115.4 million, respectively.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As a result of the adoption of SFAS No. 158 on December 31, 2006, the accrued pension liability recorded on the consolidated balance sheet at December 31, 2006 reflects the projected benefit obligation less any portion of the obligation currently funded. The accumulated actuarial loss and prior service cost that had not yet been reflected in net periodic pension costs were included in Accumulated other comprehensive loss at December 31, 2006 as follows:

	(Dollars in thousands)	
Accumulated actuarial loss	$	(102,060)
Prior service cost		(379)
Accumulated other comprehensive loss	$	(102,439)

The change in Accumulated other comprehensive loss due to the application of SFAS No. 158 was as follows:

	December 31,			
	2006		2005	
	(Dollars in thousands)			
Additional minimum pension liability (before SFAS No. 158)	$	(78,110)	$	(117,328)
Intangible asset (before SFAS No. 158)		1,908		2,362
Accumulated other comprehensive loss (before SFAS No. 158)		(76,202)		(114,966)
Net decrease in accumulated other comprehensive loss due to the adoption of SFAS No. 158		(26,237)		
Accumulated other comprehensive loss	$	(102,439)	$	(114,966)

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	Year Ended December 31,	
	2006	2005
Discount rate	6.00%	5.90%
Rate of compensation increase	3.50%	3.50%
Measurement date	December 31, 2006	December 31, 2005

The weighted-average assumptions used to determine net periodic benefit cost were as follows:

	Year Ended December 31,		
	2006	2005	2004
Discount rate	5.90%	6.10%	6.40%

Expected long-term return on plan assets	8.75%	8.75%	8.75%
Rate of compensation increase	3.50%	3.50%	3.75%
Measurement date	December 31, 2005	December 31, 2004	December 31, 2003

The expected rate of return on plan assets is determined by taking into consideration expected long-term returns associated with each major asset class (net of inflation) based on long-term historical ranges, inflation assumptions and the expected net value from active management of the assets based on actual results.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The projected benefit obligation and the accumulated benefit obligation exceeded plan assets for all plans as of December 31, 2006 and 2005. The accumulated benefit obligation for all pension plans was $808.4 million and $779.6 million as of December 31, 2006, and 2005, respectively.

Plan Assets

Assets of the Peabody Plan and the Western Plan are commingled in the Peabody Investment Corporation Master Trust (the Master Trust) and are invested in accordance with investment guidelines that have been established by the Company s Retirement Committee (the Retirement Committee) after consultation with outside investment advisors and actuaries.

As of the year ended December 31, 2006, Master Trust assets totaled $704.2 million and were invested in the following major asset categories:

	Percentage Allocation of Total Assets	Target Allocation
Equity securities	58.5%	55.0%
Fixed income	32.9%	35.0%
Real estate	7.6%	10.0%
Cash fund	1.0%	0.0%
Total	100.0%	100.0%

As of the year ended December 31, 2005, Master Trust assets totaled $654.0 million and were invested in the following major asset categories:

	Percentage Allocation of Total Assets
Equity securities	55.1%
Fixed income	37.9%
Real estate	6.9%
Cash fund	0.1%
Total	100.0%

The asset allocation targets have been set with the expectation that the plan s assets will fund the plan s expected liabilities with an appropriate level of risk. To determine the appropriate target asset allocations, the Retirement Committee considers the demographics of the plan participants, the funding status of the plan, the business and financial profile of the Company and other associated risk preferences. These allocation targets are reviewed by the Retirement Committee on a regular basis and revised as necessary. Periodically, assets are rebalanced among major asset categories to maintain the allocations within a range of plus or minus 5% of the target allocation.

Plan assets are either under active management by third-party investment advisors or in index funds, all selected and monitored by the Retirement Committee. The Retirement Committee has established specific investment guidelines for each major asset class including performance benchmarks, allowable and prohibited investment types and concentration limits. In general, the plan investment guidelines do not permit leveraging the Master Trust s assets. Equity investment guidelines do not permit entering into put or call options (except as deemed appropriate to manage currency risk), and futures contracts are permitted only to the extent necessary to equitize cash holdings.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Contributions

The Company expects to contribute $6.9 million to its funded pension plans and make $1.3 million in expected benefit payments attributable to its unfunded pension plans during 2007.

Estimated Future Benefit Payments

The following benefit payments (net of retiree contributions), which reflect expected future service, as appropriate, are expected to be paid by the Master Trust:

	Pension Benefits
	(Dollars in thousands)
2007	$ 42,757
2008	44,970
2009	46,531
2010	48,453
2011	51,014
Years 2012-2016	301,257

Multi-Employer Pension Plans

Certain subsidiaries participate in multi-employer pension plans (the 1950 Plan and the 1974 Plan), which provide defined benefits to substantially all hourly coal production workers represented by the UMWA other than those covered by the Western Plan. Benefits under the UMWA plans are computed based on service with the subsidiaries or other signatory employers. There were no contributions to the multi-employer pension plans during the years ended December 31, 2006, 2005 or 2004. In December 2006, the 2007 National Bituminous Coal Wage Agreement was signed, which required funding of the 1974 Plan through 2011 under a phased funding schedule. The funding is based on an hourly rate for certain UMWA workers. Under the labor contract, the per hour funding rate increased to $2.00 in 2007 and increases each year thereafter until reaching $5.50 in 2011. During 2006, represented employees subject to the new rate worked a total of approximately four million hours.

Defined Contribution Plans

The Company sponsors employee retirement accounts under three 401(k) plans for eligible salaried U.S. employees. The Company matches voluntary contributions to each plan up to specified levels. The expense for these plans was $16.5 million, $10.7 million and $10.2 million for the years ended December 31, 2006, 2005 and 2004, respectively. A performance contribution feature allows for additional contributions from the Company based upon meeting specified Company performance targets, and the performance contributions made by the Company were $10.5 million, $11.4 million and $6.7 million for the years ended December 31, 2006, 2005 and 2004, respectively.

(16) Postretirement Health Care and Life Insurance Benefits

The Company currently provides health care and life insurance benefits to qualifying salaried and hourly retirees and their dependents from defined benefit plans established by the Company. Plan coverage for health and life insurance benefits is provided to future hourly retirees in accordance with the applicable labor agreement.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net periodic postretirement benefit costs included the following components:

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands)		
Service cost for benefits earned	$ 8,077	$ 5,343	$ 4,430
Interest cost on accumulated postretirement benefit obligation	73,803	72,673	63,635
Amortization of prior service cost	(4,836)	(5,339)	(13,230)
Amortization of actuarial losses	31,342	26,304	3,575
Net periodic postretirement benefit costs	$ 108,386	$ 98,981	$ 58,410

The Company amortizes actuarial gains and losses using a 0% corridor with an amortization period that covers the average remaining service period of active employees (8.47 years and 8.99 years at January 1, 2006 and 2005, respectively). The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive income (loss) into net periodic postretirement benefit costs during the year ended December 31, 2007 are $43.3 million and $3.1 million, respectively.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the plans combined funded status reconciled with the amounts shown in the consolidated balance sheets:

	December 31, 2006	December 31, 2005
	(Dollars in thousands)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of period	$ 1,288,955	$ 1,234,185
Service cost	8,077	5,343
Interest cost	73,803	72,673
Participant contributions	1,800	1,716
Plan amendments	24,439	
Benefits paid	(88,667)	(87,250)
Actuarial loss	142,910	62,288
Accumulated postretirement benefit obligation at end of period	1,451,317	1,288,955
Change in plan assets:		
Fair value of plan assets at beginning of period		
Employer contributions	86,867	85,534
Participant contributions	1,800	1,716
Benefits paid	(88,667)	(87,250)
Fair value of plan assets at end of period		
Funded status at end of year	(1,451,317)	(1,288,955)
Unrecognized actuarial loss		272,617
Unrecognized prior service cost		(17,932)
Accrued postretirement benefit obligation	(1,451,317)	(1,034,270)
Less current portion (included in Accounts payable and accrued expenses)	82,631	75,048
Noncurrent obligation (included in Accrued postretirement benefit costs)	$ (1,368,686)	$ (959,222)

As a result of the adoption of SFAS No. 158 on December 31, 2006, the accrued postretirement benefit liability recorded on the consolidated balance sheet at December 31, 2006 reflects the accumulated postretirement benefit obligation less any portion that is currently funded. The accumulated actuarial loss and prior service costs that had not yet been reflected in net periodic postretirement benefit costs were included in Accumulated other comprehensive loss at December 31, 2006, as follows:

(Dollars in thousands)

Accumulated actuarial loss	$	(384,179)
Prior service cost		(11,343)
Accumulated other comprehensive loss	$	(395,522)

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	Year Ended December 31,	
	2006	2005
Discount rate	6.00%	5.90%
Rate of compensation increase	3.50%	3.50%
Measurement date	December 31, 2006	December 31, 2005

The weighted-average assumptions used to determine net periodic benefit cost were as follows:

	Year Ended December 31,		
	2006	2005	2004
Discount rate	5.90%	6.10%	6.40%
Rate of compensation increase	3.50%	3.50%	3.75%
Measurement date	December 31, 2005	December 31, 2004	December 31, 2003

The following presents information about the assumed health care cost trend rate:

	Year Ended December 31,	
	2006	2005
Health care cost trend rate assumed for next year	7.50%	7.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.75%	4.75%
Year that the rate reaches the ultimate trend rate	2012	2011

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

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in thousands)	
Effect on total service and interest cost components	$ 9,501	$ (7,989)
Effect on total postretirement benefit obligation	$ 179,264	$ (150,765)

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Plan Assets

The Company s postretirement benefit plans are unfunded.

Estimated Future Benefit Payments

The following benefit payments (net of retiree contributions), which reflect expected future service, as appropriate, are expected to be paid by the Company:

	Postretirement Benefits
	(Dollars in thousands)
2007	$ 82,631
2008	87,710
2009	91,683
2010	95,985
2011	100,312
Years 2012-2016	568,391

Medicare and Other Plan Changes

Effective November 15, 2006, the medical premium reimbursement plan was changed for salaried employees who retired after December 31, 2004. The plan change did not apply to Powder River or Lee Ranch employees. The amendment resulted in a $20.6 million increase to the retiree health care liability. The Company began recognizing the effect of the plan amendment over 10.25 years beginning November 15, 2006. The effect was $0.3 million for the year ended December 31, 2006, and is estimated to be $2.0 million for the full year ended December 31, 2007.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Company elected not to defer the effects of the Act as discussed in FASB Staff Position 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. Additionally, the Company did not elect the federal subsidy provisions of the Act; rather the Company coordinated benefits with available Medicare coverage considered the primary payer, whether or not the beneficiary enrolled and paid the required premiums.

The Company recognized a reduction in the benefit obligation on two distinct components. For plans that required amendment to incorporate the Act, the Company recognized a liability reduction of $19.1 million. This reduction was treated as a negative plan amendment and is being amortized to income over six years beginning December 15, 2003. For plans that did not require amendment, the Company recognized a liability reduction of $162.4 million. The reduction was treated as a change in the estimated cost to provide benefits to Medicare eligible beneficiaries constituting a component of the cumulative actuarial gain or loss subject to amortization in accordance with the Company s amortization method.

In July 2001, the Company adopted changes to the prescription drug program. Effective January 1, 2002, an incentive mail order and comprehensive utilization management program was added to the prescription drug program. At the time of adoption, the effect of the change on the retiree health care liability was $38.4 million. The Company began recognizing the effect of the plan amendment over three years beginning July 1, 2001. Net periodic postretirement benefit costs were reduced by $6.4 million for the year ended December 31, 2004, for this change.

In January 1999, the Company adopted reductions to the salaried employee medical coverage levels for employees retiring before January 1, 2003, which was changed to January 1, 2005, in 2002. For

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employees retiring on or after January 1, 2005, the previous medical plan was replaced with a medical premium reimbursement plan. This plan change did not apply to Powder River or Lee Ranch salaried employees. The change in the retiree health care plan resulted in a $22.4 million reduction to the salaried retiree health care liability. The Company began recognizing the effect of the plan amendment over nine years beginning January 1, 1999. The effect was $1.0 million, $1.0 million and $2.5 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Multi-Employer Benefit Plans

Retirees formerly employed by certain subsidiaries and their predecessors, who were members of the UMWA, last worked before January 1, 1976 and were receiving health benefits on July 20, 1992, receive health benefits provided by the Combined Fund, a fund created by the Coal Act. The Coal Act requires former employers (including certain subsidiaries of the Company) and their affiliates to contribute to the Combined Fund according to a formula.

The Company has recorded an actuarially determined liability representing the amounts anticipated to be due to the Combined Fund. The noncurrent portion related to this obligation as reflected within Other noncurrent liabilities in the consolidated balance sheets as of December 31, 2006 and 2005, was $25.6 million and $27.9 million, respectively. The current portion related to this obligation reflected in Accounts payable and accrued expenses in the consolidated balance sheets as of December 31, 2006 and 2005, was $5.2 million and $8.8 million, respectively.

Expense of $2.5 million was recognized related to the Combined Fund for the year ended December 31, 2006, and consisted of interest discount of $2.4 million and amortization of actuarial loss of $0.1 million. Expense of $0.9 million was recognized related to the Combined Fund for the year ended December 31, 2005, and consisted of interest discount of $1.0 million and amortization of actuarial gain of $0.1 million. Expense of $4.9 million was recognized related to the Combined Fund for the year ended December 31, 2004, and consisted of interest discount of $3.8 million and amortization of actuarial loss of $1.1 million. The Company made contributions of $8.3 million, $4.0 million and $16.6 million to the Combined Fund for the years ended December 31, 2006, 2005 and 2004, respectively.

The Coal Act also established the 1992 Benefit Plan, which provides medical and death benefits to persons who are not eligible for the Combined Fund, who retired prior to October 1, 1994 and whose employer and any affiliates are no longer in business. A prior national labor agreement established the 1993 Benefit Plan to provide health benefits for retired miners not covered by the Coal Act. The 1993 Benefit Plan provides benefits to qualifying retired former employees, who retired after September 30, 1994, of certain signatory companies which have gone out of business and 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 1992 Benefit Plan and the 1993 Benefit Plan qualify under SFAS No. 106 as multi-employer benefit plans, which allows the Company to recognize expense as contributions are made. The expense related to these funds was $5.7 million, $4.0 million and $4.4 million for the years ended December 31, 2006, 2005 and 2004, respectively.

The Surface Mining Control and Reclamation Act Amendments of 2006 (the 2006 Act), which was enacted in December 2006, amended the federal laws establishing the Combined Fund, 1992 Benefit Plan and the 1993 Benefit Plan. Among other things, the 2006 Act guarantees full funding of all beneficiaries in the Combined Fund, provides funds on a phased-in basis for the 1992 Benefit Plan, and authorizes the trustees of the 1993 Benefit Plan to determine the contribution rates through 2010 for pre-2007 beneficiaries. The new and additional federal expenditures to the Combined Fund, 1992 Benefit Plan, 1993 Benefit Plan and certain Abandoned Mine Land payments to the states and Indian tribes are collectively limited by an aggregate annual cap of $490 million. To the extent that (i) the annual funding of the programs exceeds this amount (plus the amount of interest from the Abandoned Mine Land trust

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fund paid with respect to the Combined Benefit Fund), and (ii) Congress does not allocate additional funds to cover the shortfall, contributing employers and affiliates, including some of the Company s subsidiaries, would be responsible for the additional costs.

Pursuant to the provisions of the Coal Act and the 1992 Benefit Plan, the Company was required to provide security in an amount equal to three times the annual cost of providing health care benefits for all individuals receiving benefits from the 1992 Benefit Plan who are attributable to the Company, plus all individuals receiving benefits from an individual employer plan maintained by the Company who are entitled to receive such benefits. In accordance with the 1992 Benefit Plan, the Company had outstanding letters of credit of $119.4 million as of December 31, 2006, to secure the Company s obligation. Beginning in 2007, the amount of security the Company is required to provide for the 1992 Plan is reduced to one times the annual cost to provide the above mentioned health care benefits.

(17) Stockholders Equity

Common Stock

The Company has 800.0 million authorized shares of $0.01 par value common stock. Holders of common stock are entitled to one vote per share on all matters to be voted upon by the stockholders. The holders of common stock do not have cumulative voting rights in the election of directors. Holders of common stock are entitled to receive ratably dividends if, as and when dividends are declared from time to time by the Board of Directors out of funds legally available for that purpose, after payment of dividends required to be paid on outstanding preferred stock or series common stock. Upon liquidation, dissolution or winding up, any business combination or a sale or disposition of all or substantially all of the assets, the holders of common stock are entitled to receive ratably the assets available for distribution to the stockholders after payment of liabilities and accrued but unpaid dividends and liquidation preferences on any outstanding preferred stock or series common stock. The common stock has no preemptive or conversion rights and is not subject to further calls or assessment by the Company. There are no redemption or sinking fund provisions applicable to the common stock.

Effective February 22, 2006, the Company implemented a two-for-one stock split on all shares of its common stock. The Company had a similar two-for-one stock split on March 30, 2005. All share and per share amounts in these consolidated financial statements and related notes reflect the stock splits.

On March 23, 2004, the Company completed an offering of 35.3 million shares of the Company s common stock, priced at $11.25 per share. Net proceeds from the offering, after deducting underwriting discounts and commissions and other expenses, were $383.1 million, and were primarily used, as discussed in Note 4, to fund the acquisition of three coal operations from RAG Coal International AG.

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The following table summarizes common share activity from December 31, 2003 to December 31, 2006:

	Shares Outstanding
December 31, 2003	**218,587,016**
Equity offering	35,300,000
Stock options exercised	4,953,868
Employee stock purchases	297,648
Stock grants to non-employee directors	17,512
Shares repurchased	(20,136)
December 31, 2004	**259,135,908**
Stock options exercised	3,633,750
Stock grants to employees	375,400
Employee stock purchases	210,750
Stock grants to non-employee directors	1,594
December 31, 2005	**263,357,402**
Stock options exercised	1,940,539
Stock grants to employees	566,631
Employee stock purchases	156,785
Stock grants to non-employee directors	10,440
Shares repurchased	(2,184,958)
December 31, 2006	**263,846,839**

Preferred Stock and Series Common Stock

In addition to the common stock, the Board of Directors is authorized to issue up to 10.0 million shares of preferred stock and up to 40.0 million shares of series common stock. The Board of Directors is authorized to determine the terms and rights of each series, including the number of authorized shares, whether dividends (if any) will be cumulative or non-cumulative and the dividend rate of the series, redemption or sinking fund provisions, conversion terms, prices and rates, and amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company. The Board of Directors may also determine restrictions on the issuance of shares of the same series or of any other class or series, and the voting rights (if any) of the holders of the series. There were no outstanding shares of preferred stock or series common stock as of December 31, 2006.

Perpetual Preferred Stock

As discussed in Note 12, the Company issued $732.5 million aggregate principal amount of Debentures on December 20, 2006. Perpetual preferred stock issued upon a conversion of Debentures will be fully paid and non-assessable, and holders will have no preemptive or preferential right to purchase any of the Company s other securities. The perpetual preferred stock has a liquidation preference of $1,000 per share, is not convertible and is redeemable at the Company s option at any time at a cash redemption price per share equal to the liquidation preference plus any accumulated dividends. Holders are entitled to receive cumulative dividends at an annual rate of 3.0875% if and when declared by the Company s Board of Directors. After the Company has failed to pay dividends on the perpetual preferred stock for five years, or upon the occurrence of a mandatory trigger event, as defined in the certificate of designations governing

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the perpetual preferred stock, the Company generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay accumulated dividends after the payment in full of any deferred interest on the Debentures, subject to certain limitations. In the event of a mandatory trigger event, the Company may not declare dividends on the perpetual preferred stock other than those funded through the sale of warrants or preferred stock as described above. Any deferred interest on the Debentures at the time of notice of conversion will be reflected as accumulated dividends on the perpetual preferred stock at issuance. Additionally, holders of the perpetual preferred stock are entitled to elect two additional members to serve on the Company s Board of Directors if (i) prior to any remarketing of the perpetual preferred stock, the Company fails to declare and pay dividends with respect to the perpetual stock for ten consecutive years or (ii) after any successful remarketing or any final failed remarketing of the perpetual preferred stock, the Company fails to declare and pay six dividends thereon, whether or not consecutive. The perpetual preferred stock may be remarketed at the holder s election after December 15, 2046 or earlier, upon the first occurrence of a change of control if the Company does not redeem the perpetual preferred stock. There were no outstanding shares of perpetual preferred stock as of December 31, 2006.

Preferred Share Purchase Rights Plan and Series A Junior Participating Preferred Stock

Each outstanding share of common stock, par value $0.01 per share, of the Company carries one preferred share purchase right (a Right). The Rights are governed by a plan that expires in August 2012.

The Rights have certain anti-takeover effects. The Rights will cause substantial dilution to a person or group that attempts to acquire the Company on terms not approved by the Company s Board of Directors, except pursuant to any offer conditioned on a substantial number of Rights being acquired. The Rights should not interfere with any merger or other business combination approved by the Board of Directors since the Rights may be redeemed by the Company at a redemption price of $0.001 per Right prior to the time that a person or group has acquired beneficial ownership of 15% or more of the common stock of the Company. In addition, the Board of Directors is authorized to reduce the 15% threshold to not less than 10%.

Each Right entitles the holder to purchase one quarter of one-hundredth of a share of series A junior participating preferred stock from the Company at an exercise price of $27.50, which in turn provides rights to receive the number of common stock shares having a market value of two times the exercise price of the Right. The Right is exercisable only if a person or group acquires 15% or more of the Company s common stock. The Board of Directors is authorized to issue up to 1.5 million shares of series A junior participating preferred stock. There were no outstanding shares of series A junior participating preferred stock as of December 31, 2006.

Treasury Stock

In July 2005, the Company s Board of Directors authorized a share repurchase program of up to 5% of the then outstanding shares of its common stock, or approximately 13.1 million shares. The repurchases may be made from time to time based on an evaluation of the Company s outlook and general business conditions, as well as alternative investment and debt repayment options. During the year ended December 31, 2006, the Company repurchased 2,184,958 of its common shares at a cost of $99.8 million.

During the year ended December 31, 2004, the Company received 20,136 shares of common stock as consideration for employees exercise of stock options. The value of the common stock tendered by employees to exercise stock options was based upon the closing price on the dates of the respective transactions. The common stock tenders were in accordance with the provisions of the 1998 Stock Purchase and Option Plan, which was previously approved by the Company s Board of Directors.

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(18) Share-Based Compensation

The Company recognizes share-based compensation expense in accordance with SFAS No. 123(R), which it adopted on January 1, 2006, and utilizes restricted stock, nonqualified stock options, performance units, and an employee stock purchase plan as part of its share-based compensation program. The Company has four equity incentive plans for employees and non-employee directors that in the aggregate allow for the issuance of share-based compensation in the form of stock appreciation rights, restricted stock, performance awards, incentive stock options, nonqualified stock options and stock units. Members of the Company s Board of Directors are eligible for stock option and restricted stock grants at the date of their election and annually in January. These plans made 47.4 million shares of the Company s common stock available for grant, with 15.0 million shares available for grant as of December 31, 2006. Additionally, in 2001, the Company established an employee stock purchase plan that provided for the purchase of up to 6.0 million shares of the Company s common stock.

The Company began utilizing restricted stock as part of its equity-based compensation strategy in January 2005. Accounting for restricted stock awards was not changed by the adoption of SFAS No. 123(R). The Company recognized $4.2 million and $0.9 million of expense, net of taxes, for the years ended December 31, 2006 and 2005, respectively, related to restricted stock. For share-based payment instruments excluding restricted stock, the Company recognized $17.7 million (or $0.07 per diluted share), $24.8 million (or $0.09 per diluted share) and $12.8 million (or $0.05 per diluted share) of expense, net of taxes, for the years ended December 31, 2006, 2005 and 2004, respectively. As a result of adopting SFAS No. 123(R), the Company s net income for the year ended December 31, 2006 was $4.4 million (or $0.02 per diluted share) lower than if it had continued to account for share-based compensation under APB Opinion No. 25. Share-based compensation expense is recorded in Selling and administrative expenses in the consolidated statements of operations. As of December 31, 2006, the total unrecognized compensation cost related to nonvested awards was $24.0 million, net of taxes, which is expected to be recognized over 5.0 years with a weighted-average period of 1.3 years.

The Company used the Black-Scholes option pricing model to determine the fair value of stock options and employee stock purchase plan share-based payments made before and after the adoption of SFAS No. 123(R). The Company utilized U.S. Treasury yields as of the grant date for its risk-free interest rate assumption, matching the treasury yield terms to the expected life of the option or vesting period of the performance unit awards. The Company utilized historical, company data to develop its dividend yield, expected volatility and expected option life assumptions.

Stock Options

Employee and director stock options granted since the Company s initial public offering (IPO) of common stock in May 2001 generally vest ratably over three years and expire after ten years from the date of the grant, subject to earlier termination upon discontinuation of an employee s service. Options granted prior to the IPO generally cliff vest in 2007 and 2010. Of the 9.3 million options outstanding at December 31, 2006, 4.1 million options cliff vest in November 2007. Option grants are typically made in January of each year or following the inception of employment for employees hired during the year who are eligible to participate in the plan. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The Company recognized expense, net of taxes, of $4.7 million, $0.1 million and $0.2 million for the years ended December 31, 2006, 2005 and 2004, respectively, related to stock option grants to employees and non-employee directors.

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A summary of outstanding option activity under the plans is as follows:

	Year Ended December 31, 2006	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value (in millions)
Beginning balance	10,783,786	$ 6.37		
Granted	542,784	43.08		
Exercised	(1,940,539)	8.05		
Forfeited	(65,313)	5.69		
Outstanding	9,320,718	$ 8.16	4.0	$ 302.0
Vested and Exercisable	2,515,670	$ 8.39	5.9	$ 80.6
Outstanding options:				
Granted Pre-IPO	5,584,616			
Granted Post-IPO	3,736,102			
	9,320,718			
Vested and exercisable options:				
Granted Pre-IPO	235,720			
Granted Post-IPO	2,279,950			
	2,515,670			

During the years ended December 31, 2006, 2005 and 2004, the total intrinsic value of options exercised, defined as the excess fair value of the underlying stock over the exercise price of the options, was $84.2 million, $77.6 million and $40.5 million, respectively. The weighted-average fair values of the Company s stock options and the assumptions used in applying the Black-Scholes option pricing model (for grants during the years ended December 31, 2006, 2005 and 2004) were as follows:

	December 31, 2006	2005	2004
Weighted-average fair value	$ 16.52	$ 8.03	$ 4.46
Risk-free interest rate	4.3%	3.6%	3.9%
Expected option life	6.0 years	5.7 years	5.9 years
Expected volatility	36%	40%	40%
Dividend yield	0.8%	1.0%	1.0%

Prior to adopting SFAS No. 123(R), the Company applied APB Opinion No. 25 and related interpretations to account for its equity incentive plans. The following table reflects 2005 and 2004 pro forma net income and basic and diluted earnings per share had compensation cost been determined for the

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Company s non-qualified and incentive stock options based on the fair value at the grant dates consistent with the methodology set forth under SFAS No. 123:

	Year Ended December 31,	
	2005	2004
	(Dollars in thousands except per share data)	
Net income:		
As reported	$ 422,653	$ 175,387
Pro forma	418,704	168,628
Basic earnings per share:		
As reported	$ 1.62	$ 0.71
Pro forma	1.60	0.68
Diluted earnings per share:		
As reported	$ 1.58	$ 0.69
Pro forma	1.56	0.66

Performance Units

Performance units, which are typically granted annually in January, vest over a three-year measurement period, subject to the achievement of performance goals and stock price performance at the conclusion of the three years. Three performance unit grants were outstanding during 2006 (the 2004, 2005 and 2006 grants) and 2005 (the 2003, 2004 and 2005 grants). The payout related to the 2003 grant (which was settled in cash in February 2006) was based on the Company s stock price performance compared to both an industry peer group and a S&P index. The payouts related to the 2004 grant (which will be settled in cash in January 2007) and 2005 and 2006 grants (which will be settled in common stock in 2008 and 2009, respectively) are based 50% on stock price performance compared to both an industry peer group and a S&P index (a market condition under SFAS No. 123(R)) and 50% on a return on capital target (a performance condition under SFAS No. 123(R)). During the years ended December 31, 2006, 2005, and 2004, the Company granted 0.2 million, 0.2 million and 0.5 million performance units in each period, respectively. Under APB Opinion No. 25, all of the performance unit awards were accounted for as variable awards. Under SFAS No. 123(R), the awards settled in cash are accounted for as liability awards and adjusted to fair value at each period-end, and the awards settled in common stock are accounted for based on their grant date fair value. The performance condition awards were valued utilizing the grant date fair values of the Company s stock adjusted for dividends foregone during the vesting period. The market condition awards were valued utilizing a Monte Carlo simulation which incorporates the total shareholder return hurdles set for each grant. The Company recognized expense, net of taxes, of $11.7 million, $24.7 million, and $12.6 million for the years ended December 31, 2006, 2005, and 2004, respectively, related to performance units. The assumptions used in the valuations for grants during the years ended December 31, 2006 and 2005 were as follows:

	December 31,	
	2006	2005
Risk-free interest rate	4.3%	3.3%
Expected volatility	36%	40%
Dividend yield	0.8%	1.0%

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Employee Stock Purchase Plan

Based on the Company s employee stock purchase plan, eligible full-time and part-time employees are able to contribute up to 15% of their base compensation into this plan, subject to a limit of $25,000 per person per year. Employees are able to purchase Company common stock at a 15% discount to the lower of the fair market value of the Company s common stock on the initial or final trading dates of each six-month offering period. Offering periods begin on January 1 and July 1 of each year. The fair value of the six-month look-back option in the Company s employee stock purchase plan is estimated by adding the fair value of 0.15 of one share of stock to the fair value of 0.85 of an option on one share of stock. The Company recognized expense, net of taxes, of $1.3 million for the year ended December 31, 2006 related to its employee stock purchase plan. Shares purchased under the plan were 0.2 million, 0.2 million and 0.3 million for the years ended December 31, 2006, 2005 and 2004, respectively.

(19) Accumulated Other Comprehensive Income (Loss)

The following table sets forth the after-tax components of comprehensive income (loss):

	Foreign Currency Translation Adjustment	Minimum Pension Liability Adjustment	Net Actuarial Loss Associated with Postretirement Plans and Workers Compensation Obligations	Prior Service Cost Associated with Postretirement Plans	Cash Flow Hedges	Total Accumulated Other Comprehensive Loss
	(Dollars in thousands)					
December 31, 2003	$ 3,153	$ (77,684)	$	$	$ (7,041)	$ (81,572)
Net increase in value of cash flow hedges					17,329	17,329
Reclassification from other comprehensive income to earnings					(2,414)	(2,414)
Current period change		6,039				6,039
December 31, 2004	$ 3,153	$ (71,645)	$	$	$ 7,874	$ (60,618)
Net increase in value of cash flow hedges					36,154	36,154
Reclassification from other comprehensive income to earnings					(24,733)	(24,733)
Current period change		2,402				2,402
December 31, 2005	$ 3,153	$ (69,243)	$	$	$ 19,295	$ (46,795)
					45,799	45,799

Net increase in value of cash flow hedges						
Reclassification from other comprehensive income to earnings					(21,452)	(21,452)
Current period change		22,377				22,377
Adjustment to initially apply SFAS No. 158		46,866	(288,820)	(7,033)		(248,987)
December 31, 2006	$ 3,153	$	$ (288,820)	$ (7,033)	$ 43,642	$ (249,058)

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Comprehensive income differs from net income by the amount of unrealized gain or loss resulting from valuation changes of the Company s cash flow hedges (which include fuel and natural gas hedges, currency forwards and interest rate swaps) during the periods, and for the year ended December 31, 2006, the adjustment required by SFAS No. 158 to record the funded status of the Company s pension and other post-retirement benefit plans. The values of the Company s cash flow hedging instruments are affected by changes in interest rates, crude oil, heating oil and natural gas prices and the U.S. dollar/ Australian dollar exchange rate.

(20) Related Party Transactions

On March 23, 2004, August 4, 2003, and May 7, 2003, Lehman Brothers Merchant Banking Partners II L.P. and affiliates (Merchant Banking Fund), the Company s largest stockholder as of those dates, sold 41.1 million, 21.6 million, and 22.5 million shares, respectively, of the Company s common stock. The Company did not receive any proceeds from the sales of shares by Merchant Banking Fund. The March 2004 offering completed Merchant Banking Fund s planned exit strategy and eliminated the remaining portion of their beneficial ownership of the Company.

Lehman Brothers Inc. (Lehman Brothers) is an affiliate of the Merchant Banking Fund. In March 2004, Morgan Stanley and Lehman Brothers served as joint managers in connection with the secondary equity offering discussed above. Lehman Brothers received from third parties customary underwriting discounts and commissions from the offering. The Company paid no fees to Lehman Brothers related to the secondary equity offerings.

Lehman Brothers served as lead underwriter in connection with the Company s sale of limited partner interests in PVR in March 2004 and December 2003, as discussed in Note 9 above. Lehman Brothers received customary fees, plus reimbursement of certain expenses, for those services.

(21) Guarantees and Financial Instruments With Off-Balance-Sheet Risk

In the normal course of business, the Company is a party to guarantees and financial instruments with off-balance-sheet risk, such as bank letters of credit, performance or surety bonds and other guarantees and indemnities, which are not reflected in the accompanying consolidated balance sheets. Such financial instruments are valued based on the amount of exposure under the instrument and the likelihood of required performance. In the Company s past experience, virtually no claims have been made against these financial instruments. Management does not expect any material losses to result from these guarantees or off-balance-sheet instruments.

Letters of Credit and Bonding

The Company has letters of credit, surety bonds and corporate guarantees (such as self bonds) in support of the Company s reclamation, lease, workers compensation, retiree healthcare and other obligations as follows as of December 31, 2006:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Retiree Healthcare Obligations	Other[(1)]	Total
	(Dollars in thousands)					
Self Bonding	$ 685,235	$	$	$	$ 2,917	$ 688,152
Surety Bonds	441,524	83,877	31,646		27,245	584,292
Letters of Credit	4,125	20,282	156,826	119,397	208,783	509,413
	$ 1,130,884	$ 104,159	$ 188,472	$ 119,397	$ 238,945	$ 1,781,857

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(1) Other includes the three letter of credit obligations described below and an additional $54.1 million in self-bonding, letters of credit and surety bonds related to collateral for surety companies, road maintenance, performance guarantees and other operations.

The Company owns a 30.0% interest in a partnership that leases a coal export terminal from the Peninsula Ports Authority of Virginia under a 30-year lease that permits the partnership to purchase the terminal at the end of the lease term for a nominal amount. The partners have severally (but not jointly) agreed to make payments under various agreements which in the aggregate provide the partnership with sufficient funds to pay rents and to cover the principal and interest payments on the floating-rate industrial revenue bonds issued by the Peninsula Ports Authority, and which are supported by letters of credit from a commercial bank. As of December 31, 2006, the Company s maximum reimbursement obligation to the commercial bank was in turn supported by a letter of credit totaling $42.8 million.

The Company is party to an agreement with the Pension Benefit Guarantee Corporation (PBGC) and TXU Europe Limited, an affiliate of the Company s former parent corporation, under which the Company is required to make special contributions to two of the Company s defined benefit pension plans and to maintain a $37.0 million letter of credit in favor of the PBGC. If the Company or the PBGC gives notice of an intent to terminate one or more of the covered pension plans in which liabilities are not fully funded, or if the Company fails to maintain the letter of credit, the PBGC may draw down on the letter of credit and use the proceeds to satisfy liabilities under the Employee Retirement Income Security Act of 1974, as amended. The PBGC, however, is required to first apply amounts received from a $110.0 million guarantee in place from TXU Europe Limited in favor of the PBGC before it draws on the Company s letter of credit. On November 19, 2002 TXU Europe Limited was placed under the administration process in the United Kingdom (a process similar to bankruptcy proceedings in the United States) and continues under this process as of December 31, 2006. As a result of these proceedings, TXU Europe Limited may be liquidated or otherwise reorganized in such a way as to relieve it of its obligations under its guarantee.

In conjunction with the acquisition of Excel, the Company issued a $105.0 million letter of credit as collateral for bank guarantees issued with respect to certain reclamation and performance obligations.

Other Guarantees

As part of arrangements through which the Company obtains exclusive sales representation agreements with small coal mining companies (the Counterparties), the Company issued financial guarantees on behalf of the Counterparties. These guarantees facilitate the Counterparties efforts to obtain bonding or financing. In July 2006, the Company issued $5.2 million of financial guarantees, expiring at various dates through July 2013, on behalf of a certain Counterparty to facilitate its efforts in obtaining financing. In the event of default, the Company has multiple recourse options, including the ability to assume the loans and procure title and use of the equipment purchased through the loans. If default occurs, the Company has the ability and intent to exercise its recourse options, so the liability associated with the guarantee has been valued at zero. The Company also guaranteed bonding for a partnership in which it formerly held an interest. The aggregate amount guaranteed by the Company for all such Counterparties was $12.1 million, and the fair value of the guarantees recognized as a liability was $0.4 million as of December 31, 2006. The Company s obligations under the guarantees extend to September 2015.

In March 2006, the Company issued a guarantee for certain equipment lease arrangements on behalf of one of the sales representation parties with maximum potential future payments totaling $2.7 million at December 31, 2006, and with lease terms that extend to April 2010. The Company has multiple recourse options in the event of default, including the ability to assume the lease and procure use of the equipment

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or to settle the lease and take title to the assets. If default occurs, the Company has the ability and intent to exercise its recourse options, so the liability associated with the guarantee has been valued at zero.

The Company is the lessee under numerous equipment and property leases. It is common in such commercial lease transactions for the Company, as the lessee, to agree to indemnify the lessor for the value of the property or equipment leased, should the property be damaged or lost during the course of the Company s operations. The Company expects that losses with respect to leased property would be covered by insurance (subject to deductibles). The Company and certain of its subsidiaries have guaranteed other subsidiaries performance under their various lease obligations. Aside from indemnification of the lessor for the value of the property leased, the Company s maximum potential obligations under its leases are equal to the respective future minimum lease payments as presented in Note 9, and the Company assumes that no amounts could be recovered from third parties.

The Company has provided financial guarantees under certain long-term debt agreements entered into by its subsidiaries, and substantially all of the Company s subsidiaries provide financial guarantees under long-term debt agreements entered into by the Company. The maximum amounts payable under the Company s debt agreements are equal to the respective principal and interest payments. See Note 12 for the descriptions of the Company s (and its subsidiaries) debt. Supplemental guarantor/non-guarantor financial information is provided in Note 26.

In connection with the sale of Citizens Power LLC (Citizens Power), the Company has indemnified the buyer from certain losses resulting from specified power contracts and guarantees. The indemnity is described in detail in Note 23. A discussion of the Company s accounts receivable securitization is included in Note 6 to the consolidated financial statements.

(22) Fair Value of Financial Instruments

The following methods and assumptions were used by the Company in estimating its fair value disclosures for financial instruments as of December 31, 2006 and 2005:

Cash and cash equivalents, accounts receivable and accounts payable and accrued expenses have carrying values which approximate fair value due to the short maturity or the financial nature of these instruments.

The fair value of the Company s coal trading assets and liabilities was determined as described in Note 5.

Long-term debt fair value estimates are based on observed prices for securities with an active trading market when available, and otherwise on estimated borrowing rates to discount the cash flows to their present value. The 7.875% Senior Notes due 2026 and the 5.0% Subordinated Note carrying amount are net of unamortized note discount.

The fair values of interest rate swap contracts, currency forward contracts, explosives hedge contracts and fuel hedge contracts were provided by the respective contract counterparties, and were based on benchmark transactions entered into on terms substantially similar to those entered into by the Company and the contract counterparties. Based on these estimates as of December 31, 2006, the Company would have paid $10.9 million and $6.6 million, respectively, upon liquidation of its interest rate swaps and explosives hedges and would have received $64.1 million and $12.9 million, respectively, upon liquidation of its currency forwards and diesel fuel hedges.

At December 31, 2005, Other noncurrent liabilities included a deferred purchase obligation related to the prior purchase of a mine facility. The fair value estimate was based on the same assumption as long-term debt. This obligation was paid in full during 2006.

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The carrying amounts and estimated fair values of the Company s debt and deferred purchase obligation are summarized as follows:

	December 31, 2006		December 31, 2005	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(Dollars in thousands)			
Long-term debt	$3,263,826	$3,297,384	$1,405,506	$1,389,666
Deferred purchase obligation			1,397	1,402

See Note 2 for a discussion of the Company s derivative financial instruments.

(23) Commitments and Contingencies

Commitments

As of December 31, 2006, purchase commitments for capital expenditures were $125.8 million. Commitments for expenditures to be made under coal leases are reflected in Note 9.

Litigation Relating to Continuing Operations

Navajo Nation Litigation

On June 18, 1999, the Navajo Nation served three of the Company s subsidiaries, including Peabody Western Coal Company (Peabody Western), with a complaint that had been filed in the U.S. District Court for the District of Columbia. The Navajo Nation has alleged 16 claims, including Civil Racketeer Influenced and Corrupt Organizations Act (RICO) violations and fraud. The complaint alleges that the defendants jointly participated in unlawful activity to obtain favorable coal lease amendments. The plaintiff is seeking various remedies including actual damages of at least $600 million, which could be trebled under the RICO counts, punitive damages of at least $1 billion, a determination that Peabody Western s two coal leases have terminated due to Peabody Western s breach of these leases and a reformation of these leases to adjust the royalty rate to 20%. Subsequently, the court allowed the Hopi Tribe to intervene in this lawsuit and the Hopi Tribe is also seeking unspecified actual damages, punitive damages and reformation of its coal lease. On March 4, 2003, the U.S. Supreme Court issued a ruling in a companion lawsuit involving the Navajo Nation and the United States rejecting the Navajo Nation s allegation that the United States breached its trust responsibilities to the Tribe in approving the coal lease amendments. 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 are in mediation with respect to this litigation and other business issues.

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

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

Salt River Project and the other owners of the Navajo Generating Station filed a lawsuit on September 27, 1996, in the Superior Court of Maricopa County in Arizona seeking a declaratory judgment that certain costs relating to final reclamation, environmental monitoring work and mine decommissioning and costs primarily relating to retiree health care benefits are not recoverable by the Company s subsidiary, Peabody Western, under the terms of a coal supply agreement dated February 18, 1977. The contract

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

expires in 2011. The trial court subsequently ruled that the mine decommissioning costs were subject to arbitration but that the retiree health care costs were not subject to arbitration. The Company has recorded a receivable for mine decommissioning costs of $76.8 million and $74.2 million included in Investments and other assets in the consolidated balance sheets as of December 31, 2006 and 2005, respectively.

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

Gulf Power Company Litigation

On June 21, 2006, the Company s subsidiary filed a complaint in the U.S. District Court, Southern District of Illinois, seeking a declaratory judgment upholding its declaration of a permanent force majeure under a coal supply agreement with Gulf Power Company. On June 22, 2006, Gulf Power Company filed a breach of contract lawsuit against the Company s subsidiary in the U.S. District Court, Northern District of Florida, contesting the force majeure declaration and seeking damages for alleged past and future tonnage shortfalls of nearly 5 million tons under the coal supply agreement, which would have expired on December 31, 2007. The parties have filed motions to determine which court will hear the lawsuits. On October 6, 2006, the Florida District Court stayed Gulf Power s lawsuit until the Illinois court decides whether it has jurisdiction.

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

Claims and Litigation relating to Indemnities or Historical Operations

Citizens Power

In connection with the August 2000 sale of the Company s former subsidiary, Citizens Power LLC (Citizens Power), the Company has indemnified the buyer, Edison Mission Energy, from certain losses resulting from specified power contracts and guarantees. During the period that Citizens Power was owned by the Company, Citizens Power guaranteed the obligations of two affiliates to make payments to third parties for power delivered under fixed-priced power sales agreements with terms that extend through 2008. Edison Mission Energy has stated and the Company believes there will be sufficient cash flow to pay the power suppliers, assuming timely payment by the power purchasers. There is no pending litigation with respect to these indemnities at this time. In 2004, the Company incurred costs related to restructuring one of the indemnified power purchase agreements of $2.8 million, net of a tax benefit of $1.9 million. These amounts are classified within discontinued operations in the statement of operations.

Oklahoma Lead Litigation

Gold Fields Mining, LLC (Gold Fields) is a dormant, non-coal producing entity that was previously managed and owned by Hanson PLC, the Company s predecessor owner. In a February 1997 spin-off, Hanson PLC transferred ownership of Gold Fields to the Company, despite the fact that Gold Fields had no ongoing operations and the Company had no prior involvement in its past operations. Today Gold Fields is one of the Company s subsidiaries. The Company indemnified TXU Group with respect to certain claims relating to a former affiliate of Gold Fields. A predecessor of Gold Fields formerly operated

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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 is also a defendant, along with other companies, in several personal injury lawsuits involving over 50 children, arising out of the same lead mill operations. Plaintiffs in these actions are seeking compensatory and punitive damages for alleged personal injuries from lead exposure. The first personal injury trial has been scheduled for March 2007 and Gold Fields along with the former affiliate will be the only defendants. In December 2003, the Quapaw Indian tribe and certain Quapaw land owners filed a class action lawsuit against Gold Fields and five other companies. The plaintiffs are seeking compensatory and punitive damages based on a variety of theories. Gold Fields has filed a third-party complaint against the United States, and other parties. In February 2005, the state of Oklahoma on behalf of itself and several other parties sent a notice to Gold Fields and other companies regarding a possible natural resources damage claim. All of the lawsuits are pending in the U.S. District Court for the Northern District of Oklahoma.

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

Environmental Claims and Litigation

The Company is subject to applicable federal, state and local environmental laws and regulations in those countries where it conducts operations. Current and past mining operations in the United States are primarily covered by the Surface Mining Control and Reclamation Act of 1977, the Clean Water Act and the Clean Air Act but also include the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA or Superfund), the Superfund Amendments and Reauthorization Act of 1986 and the Resource Conservation and Recovery Act of 1976. Superfund and similar state laws create liability for investigation and remediation in response to releases of hazardous substances in the environment and for damages to natural resources. Under that legislation and many state Superfund statutes, joint and several liability may be imposed on waste generators, site owners and operators and others regardless of fault. These regulations could require us to do some or all of the following: (i) remove or mitigate the effects on the environment at various sites from the disposal or release of certain substances; (ii) perform remediation work at such sites; and (iii) pay damages for loss of use and non-use values.

The Company s policy is to accrue environmental cleanup-related costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures requires an assessment of many factors, including the nature and extent of contamination, the timing, extent and method of the remedial action, changing laws and regulations, advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement. The Company also assesses the financial capability and proportional share of costs of other PRPs and, where allegations are based on tentative findings, the reasonableness of its apportionment. The Company has not anticipated any recoveries from insurance carriers in the estimation of liabilities recorded in its consolidated balance sheets.

Although waste substances generated by coal mining and processing are generally not regarded as hazardous substances for the purposes of Superfund and similar legislation and are generally covered by

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the Surface Mining Control and Reclamation Act of 1977, some products used by coal companies in operations, such as chemicals, and the disposal of these products are governed by the Superfund statute. Thus, coal mines currently or previously owned or operated by the Company, and sites to which the Company has sent waste materials, may be subject to liability under Superfund and similar state laws.

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) based on CERCLA at five sites, and claims have been asserted at 18 other sites. 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 $43.0 million as of December 31, 2006 and $42.5 million as of December 31, 2005, $14.4 million and $23.6 million of which was reflected as a current liability, respectively. These amounts represent those costs that the Company believes are probable and reasonably estimable. In September 2005, Gold Fields and other PRPs received a letter from the U.S. Department of Justice alleging that the PRPs mining operations caused the Environmental Protection Agency (EPA) to incur approximately $125 million in residential yard remediation costs at Picher, Oklahoma and will cause the EPA to incur additional remediation costs relating to historical mining sites. Gold Fields has participated in the ongoing settlement discussions. 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 believes it has meritorious defenses to these claims. Gold Fields is involved in other litigation in the Picher area, and the Company indemnified TXU Group with respect to a defendant as is more fully discussed under the Oklahoma Lead Litigation caption above. Significant uncertainty exists as to whether claims will be pursued against Gold Fields in all cases, and where they are pursued, the amount of the eventual costs and liabilities, which could be greater or less than this provision.

Other

In addition, at times the Company becomes a party to other claims, lawsuits, arbitration proceedings and administrative procedures in the ordinary course of business. The Company believes that the ultimate resolution of such other pending or threatened proceedings is not reasonably likely to have a material adverse effect on its financial position, results of operations or liquidity.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(24) Summary Quarterly Financial Information (Unaudited)

A summary of the unaudited quarterly results of operations for the years ended December 31, 2006 and 2005, is presented below. Peabody Energy common stock is listed on the New York Stock Exchange under the symbol BTU.

	Year Ended December 31, 2006			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Dollars in thousands except per share and stock price data)			
Revenues	$ 1,311,810	$ 1,316,388	$ 1,264,988	$ 1,363,129
Operating profit	171,241	175,695	173,004	143,142
Net income	130,222	153,434	142,008	175,033
Basic earnings per share	$ 0.49	$ 0.58	$ 0.54	$ 0.67
Diluted earnings per share	$ 0.48	$ 0.57	$ 0.53	$ 0.65
Weighted average shares used in calculating basic earnings per share	263,491,072	263,958,590	263,444,254	262,790,879
Weighted average shares used in calculating diluted earnings per share	269,358,728	269,756,666	268,822,681	268,137,610
Stock price high and low prices	$ 52.54-$41.24	$ 76.29-$46.81	$ 59.90-$32.94	$ 48.59-$34.05
Dividends per share	$ 0.06	$ 0.06	$ 0.06	$ 0.06

Second quarter operating profit included $39.2 million of gains resulting from exchanges of coal reserves (see Note 3 for information). Net income for the second quarter included the tax benefit related to a reduction in tax reserves due to the favorable finalization of former parent companies federal tax audits, partially offset by higher pretax earnings in 2006. Operating profit in the third and fourth quarters of 2006 included $30.0 million and $28.9 million, respectively, of gains from the sale of non-strategic coal reserves and surface lands (see Note 3 for information). Operating profit for the third quarter of 2006 benefited from lower performance-based compensation expense of $20.6 million. Net income for the fourth

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

quarter of 2006 included a tax benefit related to the partial reduction in net operating loss valuation allowances (see Note 11 for information).

	Year Ended December 31, 2005			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Dollars in thousands except per share and stock price data)			
Revenues	$ 1,077,480	$ 1,108,786	$ 1,223,510	$ 1,234,677
Operating profit	80,803	129,309	150,885	157,386
Net income	51,890	95,254	113,340	162,169
Basic earnings per share	$ 0.20	$ 0.36	$ 0.43	$ 0.62
Diluted earnings per share	$ 0.19	$ 0.36	$ 0.42	$ 0.60
Weighted average shares used in calculating basic earnings per share	260,693,518	261,630,146	262,432,394	263,076,194
Weighted average shares used in calculating diluted earnings per share	266,801,306	267,620,416	268,521,976	268,975,324
Stock price high and low prices	$ 25.47-$18.38	$ 28.23-$19.68	$ 43.03-$26.01	$ 43.48-$35.22
Dividends per share	$ 0.0375	$ 0.0375	$ 0.0475	$ 0.0475

Operating profit for the first quarter of 2005 included a $31.1 million gain on the sale of PVR common units as discussed in Note 9 offset by $34.0 million of contract losses primarily related to a breach of a coal supply contract by a producer. Second quarter operating profit included $12.5 million of gains from property sales and a $12.5 million reduction of estimated contract losses recorded in the first quarter of 2005. Operating profit in the third quarter of 2005 included $43.6 million of gains resulting from exchanges of assets and an additional $6.7 million recovery of the contract losses recorded in the first quarter. Operating profit for the third quarter and fourth quarter of 2005 included charges related to long-term compensation plans of $18.6 million and $11.6 million, respectively. Net income for the fourth quarter of 2005 included the tax benefit realized from the deemed liquidation of a subsidiary as discussed in Note 11 partially offset by an increase in the valuation allowance on NOL carryforwards.

(25) Segment Information

The Company reports its operations primarily through the following reportable operating segments: Western U.S. Mining, Eastern U.S. Mining, Australian Mining and Trading and Brokerage. Western U.S. Mining operations reflect the aggregation of the Powder River Basin, Southwest and Colorado operating segments, and Eastern U.S. Mining operations reflect the aggregation of the Appalachia and Midwest operating segments. The principal business of the Western U.S. Mining, Eastern U.S. Mining and Australian Mining segments is the mining, preparation and sale of steam coal, sold primarily to electric utilities, and metallurgical coal, sold to steel and coke producers. For the year ended December 31, 2006, 87% of the Company s sales were to U.S. electricity generators, 4% were to the U.S. industrial sector, and 9% were to customers outside the United States. Western U.S. Mining operations are characterized by predominantly surface mining extraction processes, lower sulfur content and Btu of coal and longer shipping distances from the mine to the customer. Conversely, Eastern U.S. Mining operations are characterized by a majority of underground mining extraction processes, higher sulfur content and Btu of coal and shorter shipping distances from the mine to the customer. Geologically, Western operations mine bituminous and subbituminous coal deposits, and Eastern operations mine bituminous coal deposits. Australian Mining operations are characterized by both surface and underground extraction processes, mining low-sulfur, high Btu coal (metallurgical coal) as well as steam coal primarily

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

sold to an international customer base with a small portion sold to Australian steel producers and power generators. The Trading and Brokerage segment s principal business is the marketing, brokerage and trading of coal. Corporate and Other includes selling and administrative expenses, net gains on property disposals, costs associated with past mining obligations, joint venture earnings related to the Company s 25.5% investment in a Venezuelan mine and revenues and expenses related to the Company s other commercial activities such as coalbed methane, generation development and resource management.

The Company s chief operating decision maker uses Adjusted EBITDA as the primary measure of segment profit and loss. Adjusted EBITDA is defined as income from continuing operations before deducting early debt extinguishment costs, net interest expense, income taxes, minority interests, asset retirement obligation expense and depreciation, depletion and amortization.

Operating segment results for the year ended December 31, 2006 were as follows:

	Western U.S. Mining	Eastern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
			(Dollars in thousands)			
Revenues	$ 1,703,445	$ 2,035,841	$ 843,194	$ 652,029	$ 21,806	$ 5,256,315
Adjusted EBITDA	473,074	384,107	278,411	92,604	(147,792)	1,080,404
Total assets	2,628,070	1,420,795	2,784,922	240,329	2,439,940	9,514,056
Additions to property, plant, equipment and mine development	151,572	142,739	123,242	1,045	59,123	477,721
Federal coal lease expenditures	178,193					178,193
Income (loss) from equity affiliates	15	(3,778)			27,615	23,852

Operating segment results for the year ended December 31, 2005 were as follows:

	Western U.S. Mining	Eastern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
			(Dollars in thousands)			
Revenues	$ 1,611,587	$ 1,738,681	$ 598,085	$ 679,176	$ 16,924	$ 4,644,453
Adjusted EBITDA	459,039	374,628	202,582	43,058	(208,909)	870,398
Total assets	2,566,034	1,136,738	426,810	212,550	2,509,874	6,852,006
Additions to property, plant, equipment and mine development	113,047	88,320	85,335		97,602	384,304
Federal coal lease expenditures	118,364					118,364
Purchase of mining and related assets	84,695	34,988			21,512	141,195
Income from equity affiliates	14	9,718			20,364	30,096

PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Operating segment results for the year ended December 31, 2004 were as follows:

	Western U.S. Mining	Eastern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
			(Dollars in thousands)			
Revenues	$ 1,393,622	$ 1,501,352	$ 270,926	$ 454,537	$ 11,145	$ 3,631,582
Adjusted EBITDA	402,052	280,357	50,372	41,039	(214,576)	559,244
Additions to property, plant, equipment and mine development	52,541	66,418	19,665	23	13,297	151,944
Federal coal lease expenditures	114,653					114,653
Income from equity affiliates	21	8,666			3,712	12,399

A reconciliation of adjusted EBITDA to consolidated income from continuing operations follows:

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands)		
Total adjusted EBITDA	$ 1,080,404	$ 870,398	$ 559,244
Depreciation, depletion and amortization	(377,210)	(316,114)	(270,159)
Asset retirement obligation expense	(40,112)	(35,901)	(42,387)
Interest expense	(143,450)	(102,939)	(96,793)
Early debt extinguishment costs	(1,396)		(1,751)
Interest income	12,726	10,641	4,917
Income tax (provision) benefit	81,515	(960)	26,437
Minority interests	(11,780)	(2,472)	(1,282)
Income from continuing operations	$ 600,697	$ 422,653	$ 178,226

(26) Supplemental Guarantor/ Non-Guarantor Financial Information

In accordance with the indentures governing the 6.875% Senior Notes due March 2013, the 5.875% Senior Notes due March 2016, the 7.375% Senior Notes due November 2016 and the 7.875% Senior Notes due November 2026, certain wholly-owned U.S. subsidiaries of the Company have fully and unconditionally guaranteed these Senior Notes, on a joint and several basis. Separate financial statements and other disclosures concerning the Guarantor Subsidiaries are not presented because management believes that such information is not material to the Senior Note holders. The following historical financial statement information is provided for the Guarantor/ Non-Guarantor Subsidiaries.

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	Year Ended December 31, 2006				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
Total revenues	$	$ 3,978,220	$ 1,384,186	$ (106,091)	$ 5,256,315
Costs and expenses:					
Operating costs and expenses	(15,307)	3,239,215	1,038,167	(106,091)	4,155,984
Depreciation, depletion and amortization		301,363	75,847		377,210
Asset retirement obligation expense		39,483	629		40,112
Selling and administrative expenses	17,188	155,221	3,532		175,941
Other operating income:					
Net gain on disposal or exchange of assets		(121,705)	(10,457)		(132,162)
(Income) loss from equity affiliates		4,167	(28,019)		(23,852)
Interest expense	197,130	56,372	16,716	(126,768)	143,450
Early debt extinguishment costs	1,396				1,396
Interest income	(21,426)	(91,272)	(26,796)	126,768	(12,726)
Income (loss) before income taxes and minority interests	(178,981)	395,376	314,567		530,962
Income tax provision (benefit)	(59,661)	(83,903)	62,049		(81,515)
Minority interests			11,780		11,780
Net income (loss)	$ (119,320)	$ 479,279	$ 240,738	$	$ 600,697

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PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2005				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
Total revenues	$	$ 3,698,928	$ 1,037,449	$ (91,924)	$ 4,644,453
Costs and expenses:					
Operating costs and expenses	(30,188)	3,022,125	815,823	(91,924)	3,715,836
Depreciation, depletion and amortization		282,234	33,880		316,114
Asset retirement obligation expense		35,230	671		35,901
Selling and administrative expenses	3,683	176,731	9,388		189,802
Other operating income:					
Net gain on disposal or exchange of assets		(101,227)	(260)		(101,487)
Income from equity affiliates		(10,097)	(19,999)		(30,096)
Interest expense	154,307	57,060	21,175	(129,603)	102,939
Interest income	(22,759)	(90,995)	(26,490)	129,603	(10,641)
Income (loss) before income taxes and minority interests	(105,043)	327,867	203,261		426,085
Income tax provision (benefit)	(28,961)	(11,015)	40,936		960
Minority interests			2,472		2,472
Net income (loss)	$ (76,082)	$ 338,882	$ 159,853	$	$ 422,653

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PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2004				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
Total revenues	$	$ 3,170,683	$ 529,222	$ (68,323)	$ 3,631,582
Costs and expenses:					
Operating costs and expenses	(5,230)	2,577,028	462,066	(68,323)	2,965,541
Depreciation, depletion and amortization		257,027	13,132		270,159
Asset retirement obligation expense		41,081	1,306		42,387
Selling and administrative expenses	1,460	136,031	5,534		143,025
Other operating income:					
Net gain on disposal or exchange of assets		(23,386)	(443)		(23,829)
Income from equity affiliates		(11,161)	(1,238)		(12,399)
Interest expense	143,790	88,806	12,090	(147,893)	96,793
Early debt extinguishment costs	1,751				1,751
Interest income	(51,977)	(81,132)	(19,701)	147,893	(4,917)
Income (loss) from continuing operations before income taxes and minority interests	(89,794)	186,389	56,476		153,071
Income tax provision (benefit)	(25,364)	(4,677)	3,604		(26,437)
Minority interests		275	1,007		1,282
Income (loss) from continuing operations	(64,430)	190,791	51,865		178,226
Loss from discontinued operations, net of taxes		(2,839)			(2,839)
Net income (loss)	$ (64,430)	$ 187,952	$ 51,865	$	$ 175,387

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PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONSOLIDATED BALANCE SHEETS

	December 31, 2006				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
ASSETS					
Current assets					
Cash and cash equivalents	$ 272,226	$ 3,652	$ 50,633	$	$ 326,511
Accounts receivable		41,199	317,043		358,242
Inventories		146,920	68,464		215,384
Assets from coal trading activities		150,373			150,373
Deferred income taxes		106,967			106,967
Other current assets	54,007	41,221	21,635		116,863
Total current assets	326,233	490,332	457,775		1,274,340
Property, plant, equipment and mine development					
Land and coal interests		4,974,446	2,152,939		7,127,385
Buildings and improvements		769,770	123,279		893,049
Machinery and equipment		1,220,670	296,095		1,516,765
Less accumulated depreciation, depletion and amortization		(1,794,823)	(190,859)		(1,985,682)
Property, plant, equipment and mine development, net		5,170,063	2,381,454		7,551,517
Goodwill			240,667		240,667
Investments and other assets	7,235,765	34,195	100,115	(6,922,543)	447,532
Total assets	$ 7,561,998	$ 5,694,590	$ 3,180,011	$ (6,922,543)	$ 9,514,056
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities					
Current maturities of long-term debt	$ 27,350	$ 60,522	$ 7,885	$	$ 95,757
Payables and notes payable to affiliates, net	2,025,605	(2,170,567)	144,962		
Liabilities from coal trading activities		126,731			126,731
Accounts payable and accrued expenses	46,748	759,002	339,293		1,145,043
Total current liabilities	2,099,703	(1,224,312)	492,140		1,367,531

Long-term debt, less current maturities	3,017,107	12,373	138,589		3,168,069
Deferred income taxes	29,094	(25,077)	191,196		195,213
Other noncurrent liabilities	20,411	2,294,247	96,722		2,411,380
Total liabilities	5,166,315	1,057,231	918,647		7,142,193
Minority interests			33,337		33,337
Stockholders equity	2,395,683	4,637,359	2,228,027	(6,922,543)	2,338,526
Total liabilities and stockholders equity	$ 7,561,998	$ 5,694,590	$ 3,180,011	$ (6,922,543)	$ 9,514,056

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PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONSOLIDATED BALANCE SHEETS

	December 31, 2005				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in thousands)				
ASSETS					
Current assets					
Cash and cash equivalents	$ 494,232	$ 2,471	$ 6,575	$	$ 503,278
Accounts receivable	4,260	59,137	138,737		202,134
Inventories		329,116	60,655		389,771
Assets from coal trading activities		146,596			146,596
Deferred income taxes		9,027			9,027
Other current assets	21,817	23,347	9,267		54,431
Total current assets	520,309	569,694	215,234		1,305,237
Property, plant, equipment and mine development					
Land and coal interests		4,395,485	379,641		4,775,126
Buildings and improvements		696,427	96,827		793,254
Machinery and equipment		989,719	247,465		1,237,184
Less accumulated depreciation, depletion and amortization		(1,541,834)	(86,022)		(1,627,856)
Property, plant, equipment and mine development, net		4,539,797	637,911		5,177,708
Investments and other assets	4,971,500	311,512	63,432	(4,977,383)	369,061
Total assets	$ 5,491,809	$ 5,421,003	$ 916,577	$ (4,977,383)	$ 6,852,006
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities					
Current maturities of long-term debt	$ 10,625	$ 11,034	$ 926	$	$ 22,585
Payables and notes payable to affiliates, net	1,875,361	(2,355,684)	480,323		
Liabilities from coal trading activities		132,373			132,373
Accounts payable and accrued expenses	24,560	732,319	111,086		867,965
Total current liabilities	1,910,546	(1,479,958)	592,335		1,022,923
	1,312,521	69,014	1,386		1,382,921

Long-term debt, less current maturities					
Deferred income taxes	12,903	304,740	20,845		338,488
Other noncurrent liabilities	11,282	1,908,158	7,217		1,926,657
Total liabilities	3,247,252	801,954	621,783		4,670,989
Minority interests			2,550		2,550
Stockholders equity	2,244,557	4,619,049	292,244	(4,977,383)	2,178,467
Total liabilities and stockholders equity	$ 5,491,809	$ 5,421,003	$ 916,577	$ (4,977,383)	$ 6,852,006

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PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2006			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
	(Dollars in thousands)			
Cash Flows From Operating Activities				
Net cash provided by (used in) operating activities	$ (166,841)	$ 447,114	$ 315,453	$ 595,726
Cash Flows From Investing Activities				
Acquisition of Excel Coal, net of cash acquired			(1,507,775)	(1,507,775)
Additions to property, plant, equipment and mine development		(342,019)	(135,702)	(477,721)
Federal coal lease expenditures		(118,364)	(59,829)	(178,193)
Proceeds from disposal of assets, net of notes receivable		66,494	11,085	77,579
Other acquisitions, net			(44,538)	(44,538)
Additions to advance mining royalties		(9,194)	(1,827)	(11,021)
Investment in joint venture		(2,149)		(2,149)
Net cash used in investing activities		(405,232)	(1,738,586)	(2,143,818)
Cash Flows From Financing Activities				
Proceeds from long-term debt	2,579,383		912	2,580,295
Payments of short-term and long-term debt	(853,180)	(10,957)	(181,836)	(1,045,973)
Common stock repurchase	(99,774)			(99,774)
Dividends paid	(63,456)			(63,456)
Payment of debt issuance costs	(40,611)			(40,611)
Excess tax benefit related to stock options exercised	33,173			33,173
Proceeds from stock options exercised	15,617			15,617
Distributions to minority interests			(6,664)	(6,664)
Decrease of securitized interests in accounts receivable		(5,800)		(5,800)
Proceeds from employee stock purchases	4,518			4,518
Transactions with affiliates, net	(1,630,835)	(23,944)	1,654,779	
Net cash provided by (used in) financing activities	(55,165)	(40,701)	1,467,191	1,371,325
Net increase (decrease) in cash and cash equivalents	(222,006)	1,181	44,058	(176,767)
Cash and cash equivalents at beginning of year	494,232	2,471	6,575	503,278

Cash and cash equivalents at end of year	$ 272,226	$ 3,652	$ 50,633	$ 326,511

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PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2005			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
	(Dollars in thousands)			
Cash Flows From Operating Activities				
Net cash provided by (used in) operating activities	$ (126,861)	$ 648,599	$ 181,021	$ 702,759
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development		(297,040)	(87,264)	(384,304)
Purchase of mining and related assets		(56,500)	(84,695)	(141,195)
Federal coal lease expenditures			(118,364)	(118,364)
Proceeds from disposal of assets		74,103	2,124	76,227
Additions to advance mining royalties		(14,566)		(14,566)
Investment in joint venture		(2,000)		(2,000)
Net cash used in investing activities		(296,003)	(288,199)	(584,202)
Cash Flows From Financing Activities				
Proceeds from long-term debt		11,734		11,734
Payments of long-term debt	(6,250)	(12,959)	(989)	(20,198)
Dividends paid	(44,535)			(44,535)
Proceeds from stock options exercised	22,573			22,573
Distributions to minority interests		(2,498)		(2,498)
Increase of securitized interests in accounts receivable			25,000	25,000
Proceeds from employee stock purchases	3,009			3,009
Transactions with affiliates, net	273,230	(349,869)	76,639	
Net cash provided by (used in) financing activities	248,027	(353,592)	100,650	(4,915)
Net increase (decrease) in cash and cash equivalents	121,166	(996)	(6,528)	113,642
Cash and cash equivalents at beginning of year	373,066	3,496	13,074	389,636
Cash and cash equivalents at end of year	$ 494,232	$ 2,500	$ 6,546	$ 503,278

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PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2004			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
	(Dollars in thousands)			
Cash Flows From Operating Activities				
Net cash provided by (used in) operating activities	$ (81,656)	$ 296,240	$ 69,176	$ 283,760
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development		(129,511)	(22,433)	(151,944)
Federal coal lease expenditures			(114,653)	(114,653)
Proceeds from disposal of assets		38,408	931	39,339
Acquisitions, net		(193,736)	(235,325)	(429,061)
Additions to advance mining royalties		(15,989)	(250)	(16,239)
Investment in joint venture			(32,472)	(32,472)
Net cash used in investing activities		(300,828)	(404,202)	(705,030)
Cash Flows From Financing Activities				
Proceeds from long-term debt	700,000	13		700,013
Payments of long-term debt	(458,350)	(22,921)	(1,653)	(482,924)
Dividends paid	(32,568)			(32,568)
Payment of debt issuance costs	(12,875)			(12,875)
Net proceeds from equity offering	383,125			383,125
Proceeds from stock options exercised	27,266			27,266
Distributions to minority interests		(1,007)		(1,007)
Increase of securitized interests in accounts receivable			110,000	110,000
Proceeds from employee stock purchases	2,374			2,374
Transactions with affiliates, net	(268,825)	30,607	238,218	
Net cash provided by financing activities	340,147	6,692	346,565	693,404
Net increase in cash and cash equivalents	258,491	2,104	11,539	272,134
Cash and cash equivalents at beginning of year	114,575	1,392	1,535	117,502
Cash and cash equivalents at end of year	$ 373,066	$ 3,496	$ 13,074	$ 389,636

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited the consolidated financial statements of Peabody Energy Corporation as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 20, 2007. Our audits also included the financial statement schedule listed in Item 15(a). This schedule is the responsibility of the Company s management. Our responsibility is to express an opinion based on our audits. In our opinion, the financial statement schedule referred to above, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 20, 2007

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PEABODY ENERGY CORPORATION
SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions[1]	Other	Balance at End of Period
		(Dollars in thousands)			
Year Ended December 31, 2006					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 17,250	$	$	$ (576) [2]	$ 16,674
Reserve for materials and supplies	4,945	168		(414) [2]	4,699
Allowance for doubtful accounts	10,853	446		(155) [2]/[4]	11,144
Year Ended December 31, 2005					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 18,224	$ 867	$ (2,551)	$ 710[2]	$ 17,250
Reserve for materials and supplies	4,419	581	(1,574)	1,519[2]	4,945
Allowance for doubtful accounts	1,361	20,305(3)	(5,860)	(4,953) [4]	10,853
Year Ended December 31, 2004					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 14,465	$	$	$ 3,759[2]	$ 18,224
Reserve for materials and supplies	7,563	234	(4,180)	802[2]	4,419
Allowance for doubtful accounts	1,361				1,361

(1) Reserves utilized, unless otherwise indicated.

(2) Balances transferred (to) from other accounts or reserves recorded as part of a property transaction or acquisition.

(3) Includes $19.5 million for the establishment of a reserve for the collectibility of certain receivables billed prior to 2005.

(4) Reflects subsequent recovery of amounts previously reserved.

EXHIBIT INDEX

The exhibits below are numbered in accordance with the Exhibit Table of Item 601 of Regulation S-K.

Exhibit No.	Description of Exhibit
2.1	Merger Implementation Agreement, dated as of July 6, 2006, between the Registrant and Excel Coal Limited (Incorporated by reference to Exhibit 2.1 of the Registrant s Current Report on Form 8-K, filed on July 7, 2006).
2.2	Deed of Variation Merger Implementation Agreement, dated as of September 18, 2006, between the Registrant and Excel Coal Limited (Incorporated by reference to Exhibit 2.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).
3.1	Third Amended and Restated Certificate of Incorporation of the Registrant, as amended (Incorporated by reference to Exhibit 3.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
3.2	Amended and Restated By-Laws of the Registrant (Incorporated by reference to Exhibit 3.2 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 16, 2005).
4.1	Rights Agreement, dated as of July 24, 2002, between the Registrant and EquiServe Trust Company, N.A., as Rights Agent (which includes the form of Certificate of Designations of Series A Junior Preferred Stock of the Registrant as Exhibit A, the form of Right Certificate as Exhibit B and the Summary of Rights to Purchase Preferred Shares as Exhibit C) (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Registration Statement on Form 8-A, filed on July 24, 2002).
4.2	Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant, filed with the Secretary of State of the State of Delaware on July 24, 2002 (Incorporated herein by reference to Exhibit 3.1 to the Registrant s Registration Statement on Form 8-A, filed on July 24, 2002).
4.3	Certificate of Adjustment delivered by the Registrant to Equiserve Trust Company, NA., as Rights Agent, on March 29, 2005 (Incorporated by reference to Exhibit 4.2 to Amendment No. 1 to the Registrant s Registration Statement on Form 8-A, filed on March 29, 2005).
4.4	Certificate of Adjustment delivered by the Registrant to American Stock Transfer & Trust Company, as Rights Agent, on February 22, 2006 (Incorporated by reference to Exhibit 4.2 to Amendment No. 1 to the Registrant s Registration Statement on Form 8-A, filed on February 22, 2006).
4.5	Specimen of stock certificate representing the Registrant s common stock, $.01 par value (Incorporated by reference to Exhibit 4.13 of the Registrant s Form S-1 Registration Statement No. 333-55412).
4.6	$6^{7}/8$% Senior Notes Due 2013 Indenture, dated as of March 21, 2003, between the Registrant and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.27 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003, filed on May 13, 2003).
4.7	$6^{7}/8$% Senior Notes Due 2013 First Supplemental Indenture, dated as of May 7, 2003, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant s Form S-4 Registration Statement No. 333-106208).
4.8	$6^{7}/8$% Senior Notes Due 2013 Second Supplemental Indenture, dated as of September 30, 2003, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.198 of the Registrant s Form S-3 Registration Statement No. 333-109906, filed on October 22, 2003).
4.9	

	$6^7/8\%$ Senior Notes Due 2013 Third Supplemental Indenture, dated as of February 24, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.211 of the Registrant s Form S-3/ A Registration Statement No. 333-109906, filed on March 4, 2004).
4.10	$6^7/8\%$ Senior Notes Due 2013 Fourth Supplemental Indenture, dated as of April 22, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 10.57 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).

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Exhibit No.	Description of Exhibit
4.11	6^{7}/8% Senior Notes Due 2013 Fifth Supplemental Indenture, dated as of October 18, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.9 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 16, 2005).
4.12	6^{7}/8% Senior Notes Due 2013 Sixth Supplemental Indenture, dated as of January 20, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed on May 6, 2005).
4.13	6^{7}/8% Senior Notes Due 2013 Seventh Supplemental Indenture, dated as of September 30, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, filed on November 8, 2005).
4.14	6^{7}/8% Senior Notes Due 2013 Eighth Supplemental Indenture, dated as of January 20, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.14 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2005, filed on March 6, 2006).
4.15	6^{7}/8% Senior Notes Due 2013 Ninth Supplemental Indenture, dated as of June 13, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
4.16	6^{7}/8% Senior Notes Due 2013 Tenth Supplemental Indenture, dated as of June 30, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
4.17	6^{7}/8% Senior Notes Due 2013 Eleventh Supplemental Indenture, dated as of September 29, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).
4.18	6^{7}/8% Senior Notes Due 2013 Twelfth Supplemental Indenture, dated as of November 10, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee.
4.19	6^{7}/8% Senior Notes Due 2013 Thirteenth Supplemental Indenture, dated as of January 31, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee.
4.20	5^{7}/8% Senior Notes Due 2016 Indenture, dated as of March 19, 2004, between the Registrant and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.12 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, filed on May 10, 2004).
4.21	5^{7}/8% Senior Notes Due 2016 First Supplemental Indenture, dated as of March 23, 2004, between the Registrant and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K dated March 23, 2004).
4.22	5^{7}/8% Senior Notes Due 2016 Second Supplemental Indenture, dated as of April 22, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 10.58 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).

4.23	$5^{7}/8$% Senior Notes Due 2016 Third Supplemental Indenture, dated as of October 18, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.13 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 16, 2005).

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Exhibit No.	Description of Exhibit
4.24	$5^{7}/8$% Senior Notes Due 2016 Fourth Supplemental Indenture, dated as of January 20, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed on May 6, 2005).
4.25	$5^{7}/8$% Senior Notes Due 2016 Fifth Supplemental Indenture, dated as of September 30, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, filed on November 8, 2005).
4.26	$5^{7}/8$% Senior Notes Due 2016 Sixth Supplemental Indenture, dated as of January 20, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.21 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2005, filed on March 6, 2006).
4.27	$5^{7}/8$% Senior Notes Due 2016 Seventh Supplemental Indenture, dated as of June 13, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
4.28	$5^{7}/8$% Senior Notes Due 2016 Eighth Supplemental Indenture, dated as of June 30, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed on August 7, 2006).
4.29	$5^{7}/8$% Senior Notes Due 2016 Ninth Supplemental Indenture, dated as of September 29, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).
4.30	$5^{7}/8$% Senior Notes Due 2016 Twelfth Supplemental Indenture, dated as of November 10, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee.
4.31	$5^{7}/8$% Senior Notes Due 2016 Fifteenth Supplemental Indenture, dated as of January 31, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and US Bank National Association, as trustee.
4.32	$7^{3}/8$% Senior Notes due 2016 Tenth Supplemental Indenture, dated as of October 12, 2006 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K dated October 13, 2006).
4.33	$7^{3}/8$% Senior Notes due 2016 Thirteenth Supplemental Indenture, dated as of November 10, 2006 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee.
4.34	$7^{3}/8$% Senior Notes due 2016 Sixteenth Supplemental Indenture, dated as of January 31, 2007 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee.
4.35	$7^{7}/8$% Senior Notes due 2026 Eleventh Supplemental Indenture, dated as of October 12, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Current Report on Form 8-K dated October 13, 2006).
4.36	

	$7^{7}/8$% Senior Notes due 2026 Fourteenth Supplemental Indenture, dated as of November 10, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee.
4.37	$7^{7}/8$% Senior Notes due 2026 Seventeenth Supplemental Indenture, dated as of January 31, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee.
4.38	Subordinated Indenture, dated as of December 20, 2006, between the Registrant and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K, filed December 20, 2006).

Exhibit No.	Description of Exhibit
4.39	4.75% Convertible Junior Subordinated Debentures Due 2066 First Supplemental Indenture, dated as December 20, 2006, among the Registrant and US Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Current Report on Form 8-K, filed December 20, 2006).
4.40	Capital Replacement Covenant dated December 19, 2006 (Incorporated by reference to Exhibit 99.1 of the Registrant s Current Report on Form 8-K, filed December 20, 2006).
10.1	Third Amended and Restated Credit Agreement, dated as of September 15, 2006, among the Registrant, Bank of America, N.A., as administrative agent, Citibank, N.A., as syndication agent, and the lenders named therein (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed September 18, 2006).
10.2	Amendment No. 1 to Third Amended and Restated Credit Agreement, dated as of September 27, 2006, among the Registrant, the Lenders named therein, and Bank of America, N.A., as Administrative Agent (Incorporated by reference to Exhibit 10.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).
10.3	Amended and Restated Guarantee, dated as of September 15, 2006, among the Registrant and the Guarantors (as defined therein) in favor of Bank of America, N.A., as administrative agent under the Third Amended and Restated Credit Agreement dated as of September 15, 2006 (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed September 18, 2006).
10.4	Federal Coal Lease WYW0321779: North Antelope/ Rochelle Mine (Incorporated by reference to Exhibit 10.3 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.5	Federal Coal Lease WYW119554: North Antelope/ Rochelle Mine (Incorporated by reference to Exhibit 10.4 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.6	Federal Coal Lease WYW5036: Rawhide Mine (Incorporated by reference to Exhibit 10.5 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.7	Federal Coal Lease WYW3397: Caballo Mine (Incorporated by reference to Exhibit 10.6 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.8	Federal Coal Lease WYW83394: Caballo Mine (Incorporated by reference to Exhibit 10.7 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.9	Federal Coal Lease WYW136142 (Incorporated by reference to Exhibit 10.8 of Amendment No. 1 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10.10	Royalty Prepayment Agreement by and among Peabody Natural Resources Company, Gallo Finance Company and Chaco Energy Company, dated September 30, 1998 (Incorporated by reference to Exhibit 10.9 of the Registrant s Quarterly Report on Form 10-Q for the second quarter ended September 30, 1998, filed on November 13, 1998).
10.11	Federal Coal Lease WYW154001: North Antelope Rochelle South (Incorporated by reference to Exhibit 10.68 of the Registrant s Quarterly Report on Form 10-Q for the third quarter ended September 30, 2004, filed on December 10, 2004).
10.12	Federal Coal Lease WYW150210: North Antelope Rochelle Mine (Incorporated by reference to Exhibit 10.8 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed on May 6, 2005).
10.13	Federal Coal Lease WYW151134 effective May 1, 2005: West Roundup (Incorporated by reference to Exhibit 10.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, filed on August 8, 2005).
10.14*	1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 4.9 of the Registrant s Form S-8 Registration Statement No. 333-105456, filed on

	May 21, 2003).
10.15*	Form of Non-Qualified Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.15 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.16*	Form of Amendment to Non-Qualified Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.16 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).

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Exhibit No.	Description of Exhibit
10.17*	Form of Amendment, dated as of June 15, 2004, to Non-Qualified Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.65 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).
10.18*	Form of Incentive Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.17 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.19*	Long-Term Equity Incentive Plan of the Registrant (Incorporated by reference to Exhibit 99.2 of the Registrant s Form S-8 Registration Statement No. 333-61406, filed on May 22, 2001).
10.20*	Peabody Energy Corporation 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Annex A to the Registrant s Proxy Statement for the 2004 Annual Meeting of Stockholders, filed on April 2, 2004).
10.21*	Amendment No. 1 to the Peabody Energy Corporation 2004 Long Term Incentive Plan (Incorporated by reference to Exhibit 10.67 of the Registrant s Quarterly Report on Form 10-Q for the third quarter ended September 30, 2004, filed on December 10, 2004).
10.22*	Form of Non-Qualified Stock Option Agreement under the Peabody Energy Corporation 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K, filed on January 7, 2005).
10.23*	Form of Performance Units Agreement under the Peabody Energy Corporation 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, dated January 3, 2005).
10.24*	Equity Incentive Plan for Non-Employee Directors of the Registrant (Incorporated by reference to Exhibit 99.3 of the Registrant s Form S-8 Registration Statement No. 333-61406, filed on May 22, 2001).
10.25*	Form of Non-Qualified Stock Option Agreement for Outside Directors under the Peabody Energy Corporation Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K, filed on December 14, 2005).
10.26*	Form of Non-Qualified Stock Option Agreement under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.18 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.27*	Form of Performance Unit Award Agreement under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.19 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.28*	Form of Non-Qualified Stock Option Agreement under the Registrant s Equity Incentive Plan for Non-Employee Directors (Incorporated by reference to Exhibit 10.20 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.29*	Form of Restricted Stock Agreement under the Registrant s Equity Incentive Plan for Non-Employee Directors (Incorporated by reference to Exhibit 10.21 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.30*	Form of Restricted Stock Award Agreement for Outside Directors under the Peabody Energy Corporation Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K, filed on December 14, 2005).
10.31*	Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 99.1 of the Registrant s Form S-8 Registration Statement No. 333-61406, filed on May 22, 2001).
10.32*	

	First Amendment to Registrant s Employee Stock Purchase Plan, dated as of February 7, 2002 (Incorporated by reference to Exhibit 10.23 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.33*	Letter Agreement, dated as of March 1, 2005, by and between the Registrant and Irl F. Engelhardt (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed March 4, 2005).
10.34*	Amended and Restated Employment Agreement, dated as of January 1, 2006, by and between the Registrant and Irl F. Engelhardt (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K, filed March 4, 2005).
10.35*	Letter Agreement, dated as of March 1, 2005, by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed March 4, 2005).

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Exhibit No.	Description of Exhibit
10.36*	Amended and Restated Employment Agreement, dated as of January 1, 2006, by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K, filed March 4, 2005).
10.37*	Employment Agreement between Richard M. Whiting and the Registrant dated May 19, 1998 (Incorporated by reference to Exhibit 10.12 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.38*	First Amendment to the Employment Agreement between Richard M. Whiting and the Registrant dated as of May 10, 2001 (Incorporated by reference to Exhibit 10.22 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.39*	Second Amendment to the Employment Agreement between Richard M. Whiting and the Registrant dated as of June 15, 2004 (Incorporated by reference to Exhibit 10.60 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).
10.40*	Employment Agreement between Richard A. Navarre and the Registrant dated May 19, 1998 (Incorporated by reference to Exhibit 10.13 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.41*	First Amendment to the Employment Agreement between Richard A. Navarre and the Registrant dated as of May 10, 2001 (Incorporated by reference to Exhibit 10.23 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.42*	Second Amendment to the Employment Agreement between Richard A. Navarre and the Registrant dated as of June 15, 2004 (Incorporated by reference to Exhibit 10.61 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).
10.43*	Employment Agreement between Roger B. Walcott, Jr. and the Registrant dated May 19, 1998 (Incorporated by reference to Exhibit 10.14 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.44*	First Amendment to the Employment Agreement between Roger B. Walcott, Jr. and the Registrant dated as of May 10, 2001 (Incorporated by reference to Exhibit 10.24 of the Registrant s Form S-1 Registration Statement No. 333-55412).
10.45*	Second Amendment to the Employment Agreement between Roger B. Walcott and the Registrant dated as of June 15, 2004 (Incorporated by reference to Exhibit 10.62 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004).
10.46*	Letter Agreement, dated as of December 22, 2006, by and between the Registrant and Eric Ford (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10.47*	Employment Agreement, dated as of December 22, 2006, by and between the Company and Eric Ford (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10.47A*	Form of Restricted Stock Agreement Exhibit A (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10.47B*	Form of Restricted Stock Agreement Exhibit B (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10.48*	Peabody Energy Corporation Deferred Compensation Plan (Incorporated by reference to Exhibit 10.30 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, filed on October 30, 2001).
10.49*	First Amendment to the Peabody Energy Corporation Deferred Compensation Plan (Incorporated by reference to Exhibit 10.49 of the Registrant s Annual Report on Form 10-K for the year ended

	December 31, 2004, filed on March 16, 2005).
10.50*	Performance Units Agreement, dated as of August 1, 2004, by and between Registrant and Irl F. Engelhardt (Incorporated by reference to Exhibit 10.72 of the Registrant s Quarterly Report on Form 10-Q/ A for the third quarter ended September 30, 2004, filed on December 10, 2004).
10.51*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Irl F. Engelhardt (Incorporated by reference to Exhibit 10.31 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).

Exhibit No.	Description of Exhibit
10.52*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and William E. James (Incorporated by reference to Exhibit 10.34 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.53*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Henry E. Lentz (Incorporated by reference to Exhibit 10.35 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.54*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and William C. Rusnack (Incorporated by reference to Exhibit 10.36 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.55*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Dr. James R. Schlesinger (Incorporated by reference to Exhibit 10.37 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.56*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Dr. Blanche M. Touhill (Incorporated by reference to Exhibit 10.38 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.57*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Alan H. Washkowitz (Incorporated by reference to Exhibit 10.39 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.58*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and Richard A. Navarre (Incorporated by reference to Exhibit 10.40 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.59*	Indemnification Agreement, dated as of January 16, 2003, by and between Registrant and Robert B. Karn III (Incorporated by reference to Exhibit 10.41 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.60*	Indemnification Agreement, dated as of January 16, 2003, by and between Registrant and Sandra A. Van Trease (Incorporated by reference to Exhibit 10.42 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, filed on March 7, 2003).
10.61*	Indemnification Agreement, dated as of December 9, 2003, by and between Registrant and B. R. Brown (Incorporated by reference to Exhibit 10.48 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, filed on March 4, 2004).
10.62*	Indemnification Agreement, dated as of March 22, 2004, by and between Registrant and Henry Givens, Jr. (Incorporated by reference to Exhibit 10.52 of the Registrant s Quarterly Report on Form 10-Q for the quarter Ended March 31, 2004, filed on May 10, 2004).
10.63*	Indemnification Agreement, dated as of March 22, 2004, by and between Registrant and William A. Coley (Incorporated by reference to Exhibit 10.53 of the Registrant s Quarterly Report on Form 10-Q for the quarter Ended March 31, 2004, filed on May 10, 2004).
10.64*	Indemnification Agreement, dated as of April 8, 2005, by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed April 14, 2005).
10.65*	Indemnification Agreement, dated July 21, 2005, by and between the Registrant and John F. Turner (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed on August 5, 2005).
10.66	Amended and Restated Receivables Purchase Agreement, dated as of September 30, 2005, by and among Seller, the Registrant, the Sub-Servicers named therein, Market Street Funding Corporation, as Issuer, and PNC Bank, National Association, as Administrator (Incorporated by reference to

	Exhibit 10.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, filed on August 8, 2005).
21	List of Subsidiaries.
23	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
31.1	Certification of periodic financial report by the Registrant s Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of periodic financial report by the Registrant s Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description of Exhibit
32.1	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant s Chief Executive Officer.
32.2	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant s Chief Financial Officer.

* These exhibits constitute all management contracts, compensatory plans and arrangements required to be filed as an exhibit to this form pursuant to Item 15(c) of this report.

Filed herewith.