ARCH COAL INC
Form 10-K/A
August 06, 2004

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 1

(Mark One)

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

For the fiscal year ended: December 31, 2003

or

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

For the transition period from to

Commission File Number: 1-13105

ARCH COAL, INC.

(Exact name of registrant as specified in its charter)

Delaware	**43-0921172**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
One City Place Drive, Suite 300, St. Louis, MO	**63141**
(Address of principal executive offices)	(Zip Code)

(Registrant s telephone number, including area code): (314) 994-2700

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

Common Stock, $.01 par value	**New York Stock Exchange**
Preferred Share Purchase Rights	**New York Stock Exchange**
5% Perpetual Cumulative Convertible Preferred Stock	**None**
Title of Each Class	Name of Each Exchange On Which Registered

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes x No o

At June 30, 2003, based on the closing price of the registrant s common stock on the New York Stock Exchange on that date, the aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $948,857,253. In determining this amount, the registrant has assumed that all of its executive officers and directors, and persons known to it to be the beneficial owners of more than five percent of its common stock, are affiliates. Such assumption shall not be deemed conclusive for any other purpose.

At March 1, 2004, there were 53,950,004 shares of the registrant s common stock outstanding.

Documents incorporated by reference:

1. Portions of the registrant s definitive proxy statement, to be filed with the Securities and Exchange Commission no later than April 1, 2004, are incorporated by reference into Part III of this Form 10-K.

2. Portions of the registrant s Annual Report to Stockholders for the year ended December 31, 2003 are incorporated by reference into Parts I, II and IV of this Form 10-K.

EXPLANATORY NOTE

This Amendment No. 1 to the Company s Annual Report on Form 10-K amends and restates Items 1 and 3 of Part I, Items 7, 7A, 8 and 9A of Part II and Item 15 of Part IV of, and Exhibit 13 to, the Company s Annual Report on Form 10-K for the year ended December 31, 2003, as filed by the Company on March 8, 2004, primarily to provide additional information with respect to the Company s three reportable segments. This Amendment No. 1 does not include any restatement of the Company s previously filed financial statements. No information included in the original report on Form 10-K has been amended by this Form 10-K/A to reflect any information or events subsequent to the filing of the original report on Form 10-K other than as required to reflect the amendment set forth below.

PART I

ITEM 1. BUSINESS
General

Arch Coal, Inc. (Arch Coal or the Company) is one of the largest coal producers in the United States. The Company mines, processes and markets compliance and low-sulfur coal from mines located in both the eastern and western United States, enabling it to ship coal cost-effectively to most of the major domestic coal-fired electric generation facilities. As of December 31, 2003, the Company had 25 operating mines and controlled approximately 2.8 billion tons of proven and probable coal reserves. Arch Coal sold 100.6 million tons of coal in 2003. The Company sells substantially all of its coal to producers of electric power.

The Company owns a 99% membership interest in Arch Western Resources, LLC (Arch Western), a joint venture that was formed in connection with the Company s acquisition of the United States coal operations of Atlantic Richfield Company on June 1, 1998. The principal operating units of Arch Western are Thunder Basin Coal Company, L.L.C., which operates the Black Thunder mine in the Southern Powder River Basin in Wyoming; Mountain Coal Company, L.L.C., which operates the West Elk mine in Colorado; Canyon Fuel Company, LLC (Canyon Fuel), which operates three mines in Utah; and Arch of Wyoming, LLC, which operates two mines in the Hanna Basin of Wyoming. Arch Western owns 100% of the membership interests of Thunder Basin Coal Company, L.L.C., Mountain Coal Company, L.L.C. and Arch of Wyoming, LLC. Arch Western owns a 65% membership interest in Canyon Fuel, with the remaining 35% membership interest owned by ITOCHU Coal International Inc., a subsidiary of ITOCHU Corporation of Japan.

Business Environment

United States Coal Markets. Production of coal in the United States has increased from 434 million tons in 1960 to about 1.1 billion tons in 2003. The following table sets forth demand trends for United States coal by consuming sector through 2025 as compiled, preliminary(p) or forecasted(f) by the United States Department of Energy/Energy Information Agency.

Consumption by Sector	2001	2002	2003(p)	2005(f)	2010(f)	2015(f)	2020(f)	2025(f)	Annual Growth 2002-2025(f)
					(tons in millions)				
Electric Generation	964	978	999	1,032	1,136	1,200	1,301	1,477	1.8%
Industrial	65	61	61	65	65	65	66	67	0.3%
Steel Production	26	24	24	25	23	21	19	17	(1.2%)
Residential/ Commercial	4	4	4	5	5	5	5	5	0.4%
Export	49	40	43	40	35	32	27	23	(2.3%)
Total	1,108	1,107	1,131	1,167	1,264	1,323	1,418	1,589	1.6%

Electricity Generation. Coal has consistently maintained a 49% to 53% market share over competing energy sources to generate electricity during the past ten years because of its relatively low cost and its availability throughout the United States. Coal is the lowest cost fossil-fuel used for base-load electric power generation considerably less expensive than natural gas or oil. Coal-fired generation is also competitive with nuclear power generation, especially on an all-in cost per megawatt-hour basis. Hydroelectric power is inexpensive but is limited by both geography and susceptibility to seasonal and climatic conditions. Non hydropower renewable power generation accounts for only 1.9% of all the electricity generated in the U.S. and is limited by resources and/or technology. Consequently, approximately 87.6% of the coal produced in the United States in 2003 was sold in the domestic market as a fuel to the electric generation segment. The remainder of the tons were sold in 2003 as steam coal for industrial and residential purposes, into the export market, and as metallurgical coal. In addition to the relative competitiveness of coal-fired generation plants, coal consumption patterns are also influenced by the demand for electricity, governmental regulation

impacting coal production and power generation, technological developments and the location, availability and quality of competing sources of coal, as well as other fuels such as natural gas, oil and nuclear and alternative energy sources such as hydroelectric power.

Long-term demand for electric power will depend upon a variety of economic, regulatory, technological and climatic factors beyond our control. Historically, domestic demand for electric power has increased as the United States economy has grown. Two important regulatory initiatives, one designed to increase competition among utilities and lower the cost of electricity for consumers, and another to improve air quality by reducing the level of sulfur emitted from coal-burning power generation plants, have had and are expected to continue to have significant effects on the electric utility industry and its coal suppliers.

According to the Energy Information Agency, coal is expected to remain the primary fuel for electricity generation through 2025. The following table sets forth the source fuel for electricity generation from 2001 through 2025 as compiled, preliminary(p) or forecasted(f) by the Energy Information Agency.

	2001	2002	2003(f)	2005(f)	2010(f)	2015(f)	2020(f)	2025(f)	Annual Growth 2002-2025(f)
					(billion kilowatt hours)				
Coal	1,904	1,928	1,993	2,053	2,255	2,373	2,614	3,029	1.4%
Petroleum	125	88	102	70	75	122	102	97	0.4%
Natural Gas	638	683	656	754	926	1,109	1,288	1,304	2.9%
Nuclear	769	780	762	791	794	812	816	816	0.2%
Hydro/ Renewable/other	299	353	386	431	460	487	516	540	1.9%
Total	3,735	3,832	3,899	4,099	4,510	4,903	5,336	5,786	1.8%

Coal s primary advantage is its relatively low cost compared to other fuels used to generate electricity. The following table sets forth the Energy Information Agency s forecast of delivered fuel prices to electric utilities through 2025 as compiled, preliminary(p) or forecasted(f) by the Energy Information Agency. The table below is derived from the Energy Information Agency s long-term forecast published in December 2003 and is presented in 2002 dollars.

	2001	2002	2003(p)	2005(f)	2010(f)	2015(f)	2020(f)	2025(f)	Annual Growth 2002-2025(f)
					(dollars per million Btus)				
Annual Energy Outlook									
Petrol (Residual)	$4.55	$4.04	$4.65	$3.88	$3.99	$4.14	$4.31	$4.50	(0.5%)
Natural Gas	5.30	3.77	5.62	4.18	4.04	4.78	4.85	4.92	1.2%
Coal	1.25	1.25	1.24	1.23	1.22	1.20	1.17	1.18	(0.3%)

Coal Production. United States coal production was 1.1 billion tons in 2003. The following table, derived from data prepared by the Energy Information Agency, sets forth principal United States production statistics for the periods indicated as compiled or preliminary(p).

	1980	1985	1990	1995	2000	2003(p)
Total Tons (in millions)	830	884	1,029	1,033	1,074	1,076
East	566	554	627	544	508	473
West	264	330	402	489	566	603
Underground	329	349	424	396	374	354
Surface	501	555	605	637	700	722
Percent of Total Tons						
East	68%	63%	61%	53%	47%	44%
West	32	37	39	47	53	56
Underground	40	39	41	38	35	33
Surface	60	61	59	62	65	67
Number of Mines (from RDI)						
Underground	1,875	1,695	1,422	977	707	536
Surface	1,997	1,660	1,285	1,127	746	702
Total	3,872	3,355	2,707	2,104	1,453	1,238
Average Number of Mine Employees (from RDI)						
Underground	150,328	107,357	63,960	44,254	31,825	31,207
Surface	74,610	61,924	43,402	31,777	24,640	25,978
Average Production per Mine (tons in thousands)						
Underground	177	203	297	402	531	662
Surface	249	325	472	568	935	1,026

Sales and Marketing

The Company sells coal both under long-term contracts, the terms of which are greater than 12 months, and on a current market or spot basis. When the Company s coal sales contracts expire or are terminated, it is exposed to the risk of having to sell coal into the spot market, where demand is variable and prices are subject to greater volatility. Historically, the price of coal sold under long-term contracts has exceeded prevailing spot prices for coal. However, in the past several years new contracts have been priced at or near existing spot rates.

The terms of the Company s coal sales contracts result from bidding and extensive negotiations with customers. Consequently, the terms of these contracts typically vary significantly in many respects, including price adjustment features, provisions permitting renegotiation or modification of coal sale prices, coal quality requirements, quantity parameters, flexibility and adjustment mechanisms, permitted sources of supply, treatment of environmental constraints, options to extend, and force majeure, suspension, termination and assignment provisions.

Provisions permitting renegotiation or modification of coal sale prices are present in many of the Company s more recently negotiated long-term contracts and usually occur midway through a contract or every two to three years, depending upon the length of the contract. In some circumstances, customers have the option to terminate the contract if prices have increased by a specified percentage from the price at the commencement of the contract or if the parties cannot agree on a new price. The term of sales contracts has decreased significantly over the last two decades as competition in the coal industry has increased and, more recently, as electricity generators have prepared themselves for federal Clean Air Act requirements and the impending deregulation of their industry.

There are some contract terms that differ between a standard eastern United States contract and a standard western United States contract. In the eastern United States, many customers require that the coal be sampled and weighed at the destination. In the western United States, virtually all samples are taken at the source. More eastern United States coal is purchased on the spot market. The eastern United States market has more recently been a shorter-term market because of the larger number of smaller mining operations in that region. Western United States contracts sometimes stipulate that some production taxes and coal royalties be reimbursed in full by the buyer rather than as a pricing component within the contract. These items comprise a significant portion of western United States coal pricing.

Competition

The coal industry is intensely competitive, primarily as a result of the existence of numerous producers in the coal producing regions in which the Company operates. The Company competes with several major coal producers in the Central Appalachian and Powder River Basin areas. It also competes with a number of smaller producers in those and its other market regions.

Operations

As of December 31, 2003, the Company operated a total of 30 mines, all located in the United States. The Company uses four distinct extraction techniques: continuous mining, longwall mining, truck-and-shovel mining and dragline mining. Coal is transported from the Company s mining complexes to customers by means of railroad cars, river barges or trucks, or a combination of these means of transportation. As is customary in the industry, virtually all the Company s coal sales are made F.O.B. mine or loadout, meaning that customers are responsible for the cost of transporting purchased coal to their facilities.

The Company manages its production sources to supply coal within three of the major low sulfur coal producing basins in the United States the Central Appalachia Basin, Powder River Basin and the Western Bituminous Basin. These geographically distinct areas are characterized by similar geology, coal transportation routes to consumers, regulatory environments and coal quality. These regional similarities have caused market and contract pricing environments to develop by coal basin and form the basis for the Company s segmentation of its operations.

Coal prices are influenced by a number of factors and vary dramatically by region. As a result of these regional characteristics, prices of coal within a given major coal producing basin tend to be relatively consistent. The two principal components of the price of coal within a region are the price of coal at the mine, which is influenced by mine operating costs and coal quality, and transportation costs involved in moving coal from the mine to the point of use. The price of coal at the mine is influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. It is generally cheaper to mine coal seams that are thick and located close to the surface than to mine thin underground seams. Underground mining, which is the mining method the Company uses in the Western Bituminous and also a method the Company primarily uses at certain mines in Central Appalachia, is generally more expensive than surface mining, which is the mining method the Company uses in the Powder River Basin and also for certain of its Central Appalachian mines. This is the case because of the higher capital costs, including costs for modern mining equipment and construction of extensive ventilation systems and higher labor costs due to lower productivity that are associated with underground mining.

In addition to the cost of mine operations, the price of coal is also a function of quality characteristics such as heat value, sulfur, ash and moisture content. Higher carbon and lower ash content generally result in higher prices. Coal from the Central Appalachian Basin generally has a sulfur content of 0.7% to 1.5% and a high heat content of between 12,000 and 14,000 Btus per pound. The coal from the Western Bituminous region typically has a lower sulfur content of 0.50% to 1% and a lower heat content of between 10,500 and 12,5000 Btus per pound. Powder River Basin coal generally has the lowest relative sulfur content among the Company s regions, with a sulfur content of between 0.15% and 1.20%, and the lowest relative heat content, which typically is between 7,500 and 10,000 Btus per pound.

The Company s management, including its Chief Executive Officer and Chief Operating Officer, reviews and makes resource allocations based on the goal of maximizing its profits within a coal basin in light of the comparative cost structures of its various operations. Because the Company s customers purchase coal on a regional basis, contracts can generally be sourced from several different locations within a region. Once the Company has a contractual commitment to purchase an amount of coal at a certain price, the Company s central marketing group assigns contract shipments to its various mines which can be used to source the coal in the appropriate region.

The focus of the Company s operating structure is on the reduction of controllable costs. Although revenues are reported at the mine level, the Company s mine management is asked only to manage volume and revenue adjustments due to quality variances for contract shipments assigned to their mines. The Company s mine management is evaluated and compensated on the basis of operating costs per ton at the mine level, as well as on the basis of other non-financial measures such as safety and environmental results.

Based on its management structure, the Company does not utilize mine-by-mine profit as a measure to make decisions. As a result of its management of revenues on a regional basis, the reported profit at any individual mine may not be meaningful and is not indicative of the future economic prospects of the mine.

This is the case because an individual mine s profit is based on the contract shipments that are assigned to it by the central marketing group and the pricing of those contracts, with assignments typically being made on the basis of the availability of coal and the cost of transporting the coal to the customer. Therefore, a mine that is assigned a lower-price contract will have a lower profit margin than a similar mine with similar costs that ships a nearly identical product on a higher-price contract.

The following maps show the locations of the Company s significant mining operations:

Central Appalachia Operations

Powder River Basin and Western Bituminous Operations

The following table provides the location and a summary of information regarding the Company s principal mining complexes and the total sales associated with these operations for the prior three years:

Mining Complex (Location)	Captive Mine(s)(1)	Contract Mine(s)	Mining Equipment(2)	Transportation	Tons Sold 2001	Tons Sold 2002	Tons Sold 2003
Central Appalachia							
Mingo Logan (WV)	U	U	LW, C	NS	7.2	5.8	5.5
Coal-Mac (WV)	S	U(2)	L	Barge/NS/CSX	3.5	2.1	2.1
Dal-Tex (WV)(3)				CSX			
Hobet 21 (WV)	S	U	D, L, S, C(4)	CSX	5.8	5.3	5.2
Arch of West Virginia (WV)	S(2)	U	D, L, S, HW(5)	CSX	3.6	3.6	2.8
Samples (WV)	S	U, S	D, L, S(6)	Barge/CSX	6.1	5.5	5.5
Campbells Creek (WV)		U(2)		Barge	1.3	1.1	1.0
Lone Mountain (KY)	U(3)		C	NS/CSX	2.8	2.6	2.7
Pardee (VA)	S, U(2)	U, S	L, C	NS	2.0	1.6	1.5
Western United States							
Black Thunder (WY)	S		D, S(7)	UP/BN	67.6	65.1	62.6
Coal Creek (WY)(8)				UP/BN			
West Elk (CO)	U		LW, C	UP	5.2	6.7	6.5
Skyline (UT)(9)	U		LW, C	UP	3.8	3.4	3.1
SUFCO (UT)(9)	U		LW, C	UP	7.1	7.2	7.5
Dugout Canyon (UT)(9)	U		LW, C	UP	1.8	2.0	2.5
Arch of Wyoming (WY)	S(2)		D, S(10)	UP	0.7	0.6	0.5
Totals					118.5	112.6	109.0

S	=	Surface Mine	D	=	Dragline	UP	=	Union Pacific Railroad
U	=	Underground Mine	L	=	Loader/ Truck	CSX	=	CSX Transportation
			S	=	Shovel/ Truck	BN	=	Burlington Northern Railroad
			LW	=	Longwall	NS	=	Norfolk Southern Railroad
			C	=	Continuous Miner			
			HW	=	Highwall Miner			

(1) Amounts in parenthesis indicate the number of captive and contract mines at the mining complex or location. Captive mines are mines which the Company owns and operates on land owned or leased by it. Contract mines are mines which other operators mine for the Company under contracts on land owned or leased by the Company.

(2) Reported for captive operations only.

(3) The Company idled its mining operations at the Dal-Tex complex on July 23, 1999 due to a delay in obtaining mining permits resulting from legal action in the U.S. District Court for the Southern District of West Virginia.

(4) Utilizes an 83-cubic-yard dragline and a 51-cubic-yard shovel. A dragline is a large machine used in the surface mining process to remove layers of earth and rock covering coal.

(5) Utilizes a 53-cubic-yard dragline, a 43-cubic-yard shovel, a 22-cubic-yard shovel and a 28-cubic-yard loader at the Ruffner mine.

(6) Utilizes a 105-cubic-yard dragline, two 53-cubic-yard shovels and three 28-cubic-yard loaders.

(7) Utilizes 164-cubic-yard, 130-cubic-yard, 78-cubic-yard and 45-cubic-yard draglines and 53-cubic-yard, 60-cubic-yard and 82-cubic-yard shovels.

(8) The Company idled its mining operations at Coal Creek during the third quarter of 2000 because of unfavorable conditions existing in the market environment.

(9) Mines are operated by Canyon Fuel. Canyon Fuel is an equity investment, and its financial statements and tons produced are not consolidated into the Company s financial statements and tons produced. Amounts represent 100% of Canyon Fuel s production and assigned reserves of which the Company has a 65% interest. The Skyline mine is scheduled to be idled by June 30, 2004.

(10) Utilizes 76-cubic-yard dragline at Medicine Bow and a 32-cubic-yard dragline at Seminoe II. These mines will be put into reclamation mode in 2004.

Mingo Logan. The Mingo Logan mine is an underground operation located in Mingo County and Logan County, West Virginia on approximately 11,900 acres. Six continuous miners support a longwall. The mined coal is processed through a preparation plant at the mine. The loadout facility at Mingo Logan is serviced by Norfolk Southern Railroad.

Coal-Mac. The Coal-Mac mine is located in Mingo County and Logan County, West Virginia on approximately 4,600 acres. The equipment at the mine consists of six wheel-loader spreads, 2 loadout facilities, and a preparation plant. Coal-Mac s loadout facilities are serviced by Norfolk Southern Railroad and CSX Transportation. Coal also is transported by barge from Coal-Mac.

Hobet 21. The Hobet 21 mine is located in Boone County and Lincoln County, West Virginia on approximately 13,000 acres. Equipment at Hobet 21 includes a dragline, electric shovel, wheel-loader spread and two continuous miner units. The coal at Hobet 21 is processed at an on-site preparation plant and transported from Hobet 21 s loadout facility, which is serviced by CSX Transportation.

Arch of West Virginia. The Arch of West Virginia mine is located primarily in Logan County, West Virginia on approximately 9,900 acres. A dragline, two shovels and a loader are present. The loadout facility at the mine is serviced by CSX Transportation.

Samples. The Samples mine is located primarily in Kanawha County, West Virginia on approximately 8,100 acres. Equipment at Samples includes a dragline, two shovels and three loaders. Coal from Samples is transported by rail to a loadout facility approximately 1.4 miles from the mine. CSX Transportation services this loadout. Coal also is transported by barge from this loadout.

Lone Mountain. The Lone Mountain mine is located in Harlan County, Kentucky and Lee County, Virginia on approximately 14,500 acres. Continuous miner units and continuous hauler units are present at Lone Mountain. The loadout facility at Lone Mountain is serviced by Norfolk Southern Railroad and CSX Transportation.

Black Thunder. The Black Thunder mine is located in Campbell County, Wyoming on approximately 14,711 acres. Mining the approximately 68-foot coal seam are four draglines and seven shovels. There is no washing plant at Black Thunder. The coal is crushed through either the near pit crushing and conveying system or the primary system. Coal from these two crushing facilities is conveyed into one of two silos or a slot storage facility. Coal is shipped through two loadouts on trains operated by Burlington Northern and Union Pacific.

Coal Creek. The Coal Creek mine is located in Campbell County, Wyoming on approximately 6,720 acres. Coal Creek has been idle since July 2000. The equipment at the mine consists of one shovel, ten trucks and a loadout facility. The Coal Creek mine is located on a joint rail line operated by Burlington Northern and Union Pacific.

West Elk. The West Elk mine is an underground operation located in Gunnison County, Colorado on approximately 14,700 acres. The coal is mined by two continuous miners in support of a longwall. The loadout facility at the mine is serviced by the Union Pacific Railroad.

Skyline. Canyon Fuel s Skyline mine is an underground longwall mine located in Carbon County and Emery County, Utah on approximately 11,300 acres. Three continuous miners support a longwall. The coal produced from the mine is crushed and loaded into trains at the mine. The loadout facility at Skyline is serviced by the Union Pacific Railroad. The Skyline mine is scheduled to be idled by June 30, 2004 because current market prices do not support expansion into an additional reserve base at the mine.

SUFCO. Canyon Fuel s SUFCO mine, an underground longwall mine, is located in Sevier County, Juab County and Emery County, Utah on approximately 23,900 acres. Two continuous miners support the longwall. All of the coal produced from the mine is crushed at a facility located at the mine and trucked either directly to customers or to a train loadout located approximately 80 miles from the mine. The Union Pacific Railroad serves this loadout.

Dugout Canyon. Canyon Fuel s Dugout Canyon mine is an underground longwall mine located in Carbon, County, Utah on approximately 13,700 acres. Two continuous miners support the longwall operation. The coal produced is crushed at the mine and trucked to a third party loadout served by the Union Pacific Railroad.

Transportation

Coal from the mines of the Company s subsidiaries is transported by rail, truck and barge to domestic customers and to Atlantic coast terminals for shipment to domestic and international customers.

The Company s Arch Coal Terminal is located on a 60-acre site on the Big Sandy River approximately seven miles upstream from its confluence with the Ohio River. Arch Coal Terminal provides coal storage and transloading services.

Company subsidiaries together own a 17.5% interest in Dominion Terminal Associates (DTA), which leases and operates a ground storage-to-vessel coal transloading facility (the DTA Facility) in Newport News, Virginia. The DTA Facility has a rated throughput capacity of 20 million tons of coal per year and ground storage capacity of approximately 1.7 million tons. The DTA Facility serves international customers, as well as domestic coal users located on the eastern seaboard of the United States.

Regulations Affecting Coal Mining

The information contained in the Contingencies Reclamation and Certain Trends and Uncertainties Environmental and Regulatory Factors sections of Management s Discussion and Analysis of the Company s 2003 Annual Report to Stockholders is incorporated herein by reference.

Glossary of Selected Mining Terms

Assigned Reserves. Recoverable coal reserves that have been designated for mining by a specific operation.

Auger Mining. Auger mining employs a large auger, which functions much like a carpenter s drill. The auger bores into a coal seam and discharges coal out of the spiral onto waiting conveyor belts. After augering is completed, the openings are reclaimed. This method of mining is usually employed to recover any additional coal left in deep overburden areas that cannot be reached economically by other types of surface mining.

*Btu British Thermal Unit*A measure of the energy required to raise the temperature of one pound of water one degree Fahrenheit.

Coal Seam. A bed or stratum of coal.

Coal Washing. The process of removing impurities, such as ash and sulfur based compounds, from coal.

Compliance Coal. Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btus, which is equivalent to .72% sulfur per pound of 12,000 Btu coal. Compliance coal requires no mixing with other coals or use of sulfur dioxide reduction technologies by generators of electricity to comply with the requirements of the federal Clean Air Act.

Continuous Miner. A machine used in underground mining to cut coal from the seam and load it into conveyors or into shuttle cars in a continuous operation.

Continuous Mining. One of two major underground mining methods now used in the United States (also see Longwall Mining). This process utilizes a continuous miner. The continuous miner removes or cuts the coal from the seam. The loosened coal then falls on a conveyor for removal to a shuttle car or larger conveyor belt system.

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

Dragline Mining. A method of mining where large capacity draglines remove overburden to expose the coal seams.

Longwall Mining. One of two major underground coal mining methods now used in the United States (see also Continuous Mining). This method employs a rotating drum, which is pulled mechanically back and forth across a face of coal that is usually several hundred feet long. The loosened coal falls onto a conveyor for removal from the mine. Longwall operations include a hydraulic roof support system that advances as mining proceeds, allowing the roof to fall in a controlled manner in areas already mined.

Low-Sulfur Coal. Coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btus.

Metallurgical Coal. The various grades of coal suitable for distillation into carbon in connection with the manufacture of steel. Also known as met coal.

Preparation Plant. A preparation plant is a facility for crushing, sizing and washing coal to prepare it for use by a particular customer. The washing process has the added benefit of removing some of the coal s sulfur content.

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

Proven 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 closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well established.

Reclamation. The restoration of land and environmental values to a mining site after the coal is extracted. Reclamation operations are usually underway where the coal has already been taken from a mine, even as mining operations are taking place elsewhere at the site. The process commonly includes recontouring or shaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers.

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

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

Spot Market. Sales of coal under an agreement for shipments over a period of one year or less.

Steam Coal. Coal used in steam boilers to produce electricity.

Surface Mine. A mine in which the coal lies near the surface and can be extracted by removing overburden.

Tons. References to a ton mean a short or net tonne, which is equal to 2,000 pounds.

Truck-and-Shovel Mining. An open-cast method of mining that uses large shovels to remove overburden, which is used to backfill pits after coal removal.

Unassigned Reserves. Recoverable coal reserves that have not yet been designated for mining by a specific Company operation.

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

Employees

As of March 1, 2004, the Company employed a total of approximately 3650 persons, approximately 550 of whom were represented by the UMWA under a collective bargaining agreement that expires in 2006 and approximately 125 of whom are represented by the Scotia Employees Association.

EXECUTIVE OFFICERS

The following is a list of the Company s executive officers, their ages and their positions and offices held with the Company during the last five years.

Bradley M. Allbritten, 46, is Vice President Marketing of the Company and has served in such capacity since August 2002. From March 2000 to February 2003, Mr. Allbritten was the Company s Vice President Human Resources. Mr. Allbritten served as the Company s Director of Human Resources from February 1999 through February 2000. From January 1995 to February 1999, Mr. Allbritten served as Human Resources Manager for Atlantic Richfield Company.

C. Henry Besten, Jr., 55, is Senior Vice President Strategic Development of the Company and has served in such capacity since December 2002. Mr. Besten is also President of the Company s Arch Energy Resources, Inc. subsidiary and has served in that capacity since July 1997. From July 1997 to December 2002, Mr. Besten served as Vice President Strategic Marketing of the Company. Mr. Besten also served as Acting Chief Financial Officer of the Company from December 1999 to November 2000.

John W. Eaves, 46, is Executive Vice President and Chief Operating Officer of the Company and has served in such capacity since December 2002. From February 2000 to December 2002, Mr. Eaves served as Senior Vice President Marketing of the Company and from September 1995 to December 2002 as President of the Company s Arch Coal Sales Company, Inc. subsidiary. Mr. Eaves also served as Vice President Marketing of the Company from July 1997 through February 2000. Mr. Eaves serves on the board of directors of ADA-ES, Inc.

Sheila B. Feldman, 49, is Vice President Human Resources of the Company and has served in such capacity since February 2003. From 1997 to February 2003, Ms. Feldman was the Vice President Human Resources and Public Affairs of Solutia Inc.

Robert G. Jones, 47, is Vice President Law, General Counsel and Secretary of the Company and has served in such capacity since March 2000. Mr. Jones served the Company as Assistant General Counsel from July 1997 through February 2000 and as Senior Counsel from August 1993 to July 1997.

Steven F. Leer, 51, is President and Chief Executive Officer and a Director of the Company and has served in such capacity since 1992.

Robert J. Messey, 58, is Senior Vice President and Chief Financial Officer of the Company and has served in such capacity since December 2000. Prior to joining Arch Coal, Mr. Messey served as vice president of financial services of Jacobs Engineering Group Inc. from January 1999 and, prior to that, served as senior vice president and chief financial officer of Sverdrup Corporation from 1992. Mr. Messey serves on the board of directors of Baldor Electric Company.

David B. Peugh, 49, is Vice President Business Development of the Company and has served in such capacity since 1993. Mr. Peugh is a Director of Natural Resource Partners, L.P.

Kenneth G. Woodring, 54, is Executive Vice President Mining Operations of the Company and has served in such capacity since July 1997.

ITEM 3. LEGAL CONTINGENCIES

Reference is made to Part II, Item 7 of this Annual Report on Form 10-K for the information required by Item 3.

PART II

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

Forward-Looking Statements

Statements in this annual report which are not statements of historical fact are forward-looking statements within the safe harbor provision of the Private Securities Litigation Reform Act of 1995. We base these forward-looking statements on the information available to, and the expectations and assumptions deemed reasonable by, us at the time the statements are made. Because these forward-looking statements are subject to various risks and uncertainties, actual results may differ materially from those projected in the statements. These expectations, assumptions and uncertainties include: our expectation of growth in the demand for electricity; the belief that legislation and regulations relating to the Clean Air Act and the relatively higher costs of competing fuels will increase demand for our compliance and low-sulfur coal; the expectation of continued improved market conditions for the price of coal; the expectation that we will continue to have adequate liquidity from our cash flow from operations, together with available borrowings under our credit facilities, to finance our working capital needs; a variety of operational, geologic, permitting, labor and weather related factors; and the other risks and uncertainties which are described below under Contingencies and Certain Trends and Uncertainties.

Overview

We are a producer and marketer of low-sulfur coal, which we supply principally to domestic electric utilities and independent power producers. We operate large, modern mines in the major low-sulfur coal basins in the United States. These mines are among the most productive in the regions in which they operate and are supported by an extensive, low-cost reserve base totaling 2.9 billion tons.

We derive more than 80% of our revenues from long-term supply contracts (defined as having terms of one year or greater). These supply agreements typically have terms of one to three years, although certain contracts have much longer durations. The remainder of our coal sales result from sales on the spot market.

The locations of our mining operations are as follows:

Eastern United States We operate 23 mines, all of which are located in the Central Appalachia coal basin (defined as southern West Virginia, eastern Kentucky, and Virginia). Central Appalachia is the principal source of low-sulfur coal in the eastern United States.

Western United States We operate in two coal producing regions in the western United States. We operate one surface mine and own one idle surface mine in the Powder River Basin in Wyoming. Additionally, we operate three mines and have an equity investment in the Western Bituminous regions (defined as southern Wyoming, Colorado and Utah). These mines include two surface mines in the Hanna Basin in Wyoming (which will be put into reclamation mode in 2004) and an underground longwall mine in Colorado. Our equity investment consists of a 65% interest in Canyon Fuel Company, LLC, which operates three underground longwall mines in Utah.

Coal is the dominant fuel source for electric generation in the United States. Last year, coal s share of the electric generation market increased to 51%. Furthermore, coal has significant advantages that should enable it to maintain or even increase market share over the course of the next two decades. First, coal is a low-cost fuel for electric generation, averaging less than one-third the cost of natural gas or crude oil per megawatt hour of generation. In addition, there is significant excess capacity at existing coal-based power plants, and this excess capacity represents a very low-cost source of electricity to the grid. At present, coal-based power plants are operating at an average utilization rate of around 70%. We believe that there is significant potential to increase those utilization rates and thus drive increased coal demand. The U.S. Energy Information Administration projects that coal s share of electric generation will increase to 52% by the year 2025.

The principal driver for U.S. coal demand is growth in domestic power generation. Domestic power needs are expected to grow over the next several years as the economy grows and the U.S. economy becomes increasingly electrified. The U.S. Energy Information Administration projects that power demand will grow at a rate of 1.8% annually over the course of the next two decades.

As energy demand grows, we believe that coal is well positioned to supply much of this demand, as competing fuels that have played a prominent role in meeting the nation s power needs in recent years are starting to be confronted with obstacles that could impede their future growth.

Nuclear power, the second leading source of electric generation in the U.S. with a roughly 20% share, is operating near its effective capacity. Nuclear output has remained relatively flat since peaking in 2001. It appears unlikely that any new nuclear capacity will be constructed in the next five to 10 years.

Natural gas, the source of roughly 17% of generating capacity, is currently limited by an insufficient resource base. As natural gas supplies have declined, prices have soared, with prices nearly double the average level of a few years ago. Those high prices have made natural gas plants uncompetitive, and were the principal reason that output at natural gas plants actually declined in 2003. While imports of liquefied natural gas (LNG) are expected to alleviate some of this supply pressure in the future, it will likely be several years before LNG will play a meaningful role in U.S. electric generation.

That means that coal will continue to act as the dominant fuel source for electric generation in the years ahead. In addition, we believe that low-sulfur coal will benefit disproportionately from future coal demand growth. Utilities have sought to comply with the sulfur dioxide standards contained in Phase II of the Clean Air Act by shifting increasingly to lower sulfur coals rather than building expensive scrubbing capacity. At present, only a little more than 25% of eastern coal-based power generation is equipped with scrubbers. Until more scrubbing capacity is added, we believe that low-sulfur coal will have a significant advantage in the marketplace.

Our management has positioned the company to benefit from these trends by focusing on cost containment and growth in our core operating regions.

In recent quarters, operating costs have risen due in part to higher costs associated with medical benefits, workers compensation, insurance, explosives, diesel fuel, permitting and surety bonding. We are focused on offsetting any future cost increases with cost savings and productivity improvements elsewhere. During 2004, we plan to intensify efforts at all of our mines to extend best practices; analyze major cost drivers and bottlenecks; implement process improvements; apply cutting edge maintenance programs; and invest in advanced technologies where appropriate and prudent.

We also plan to pursue growth in our key operating regions:

Our idle Coal Creek mine in Wyoming, which is permitted at 18 million tons annually, will enable us to expand production in the Powder River Basin.

In the eastern United States, we have strategic undeveloped coal reserves in southern West Virginia. We expect these reserves to support a highly efficient longwall deep mine operation as well as a very competitive surface mining operation. We are currently seeking to secure the necessary permits for these reserves.

We are likely to bid on federal reserve tracts at our western operations that will extend and enhance our reserve position in those basins.

In addition, we will consider reserve additions and acquisitions that will complement our positions in our core operating regions.

Results of Operations

Items Affecting Comparability of Reported Results

The comparison of our operating results for the years ending December 31, 2003, 2002 and 2001 are affected by the following significant items:

	Year Ended December 31,		
	2003	2002	2001
	(Amount in millions)		
Operating Income			
Gain on sale of NRP units	$ 42.7	$	$
Long-term incentive compensation accrual	(16.2)		(1.5)
Severance tax recoveries	2.5		
Reduction in workforce	(2.6)		
Gain from land sales	3.8	0.8	13.5
Gain on contract buyout		5.6	
Workers compensation premium adjustment		4.6	
Retroactive royalty rate reductions		4.4	
Reclamation adjustment Illinois properties			7.5
Litigation settlements		(1.1)	(5.6)
State tax credit			7.4
Black lung excise tax recoveries			1.5
Canyon Fuel property tax recoveries			2.6
West Elk mine insurance recoveries			9.4
Net increase in operating income	$ 30.2	$ 14.3	$ 34.8
Other			
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps	(9.0)		
Gain from mark-to-market adjustments on interest rate swaps that no longer qualify as hedges	13.4		
Interest on black lung excise tax recoveries			3.1
Net increase in pre-tax income	$ 34.6	$ 14.3	$ 37.9

Gain on Sale of NRP Units. During 2003, we sold a portion of our ownership interest in Natural Resource Partners, L.P. (NRP) for a purchase price of $115.0 million. This sale resulted in a gain of $70.6 million, of which $42.7 million was recognized in 2003 and the remainder has been deferred and will be recognized in future years.

Long-term incentive compensation plan expense. During the fourth quarter of 2003, our Board of Directors approved awards under a four-year performance unit plan that began in 2000. Amounts accrued for the plan totaled $16.2 million in 2003 and $1.5 million in 2001.

Severance Tax Recoveries. During 2003, we were notified by the State of Wyoming of a favorable ruling as it relates to our calculation of coal severance taxes. The ruling results in a refund of previously paid taxes and the reversal of previously accrued taxes payable. This amount was recorded as a component of cost of coal sales in the Consolidated Statement of Operations.

Reduction in Workforce. During the year ending December 31, 2003, we instituted cost reduction efforts throughout our operations. These cost reduction efforts included the termination of approximately 100 employees at our corporate office and eastern mining operations. Of the expense recognized, $1.6 million was recognized as a component of cost of coal sales, with the remainder recognized as a component of selling, general and administrative expenses.

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Gain from Land Sale. During the years ended December 31, 2003, 2002 and 2001, we recognized gains from land sales at our idle properties. These gains are reported as other operating income.

Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps. On June 25, 2003, we repaid the term loans of our subsidiary, Arch Western, with the proceeds from the offering of senior notes. In connection with the repayment of the term loans, we recognized expenses related to the write-off of loan fees and other debt extinguishment costs. Additionally, we had designated certain interest rate swaps as hedges of the variable rate interest payments due under the Arch Western term loans. Pursuant to the requirements of Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133), historical mark-to-market adjustments related to these swaps through June 25, 2003 were deferred as a component of Accumulated Other Comprehensive Loss. Subsequent to the repayment of the term loans, these deferred amounts will be amortized as additional expense over the contractual terms of the swap agreements. For the twelve months ending December 31, 2003, we recognized expense of $4.3 million related to the amortization of previously deferred mark-to-market adjustments. The remainder of the expense recognized represents early debt extinguishment costs.

Mark-To-Market Adjustments. We are a party to several interest rate swap agreements that were entered into in order to hedge the variable rate interest payments due under Arch Western s term loans. Subsequent to the repayment of those term loans, the swaps no longer qualify for hedge accounting under FAS 133. As such, favorable changes in the market value of the swap agreements were recorded as a component of income and are included in other non-operating income in the Consolidated Statements of Operations.

Gain on Contract Buyout. During 2002, we settled certain coal contracts with a customer that was partially unwinding its coal supply position and desired to buy out of the remaining terms of those contracts. The settlements resulted in a pre-tax gain, which was recognized in other operating income in the Consolidated Statements of Operations.

Workers Compensation Premium Adjustment. During 2002, we received a workers compensation premium adjustment refund from the State of West Virginia. During 1998, we entered into the West Virginia workers compensation plan at one of its subsidiary operations. The subsidiary paid standard base rates until the West Virginia Division of Workers Compensation could determine the actual rates based on claims experience. Upon review, the Division of Workers Compensation refunded $4.6 million in premiums. The refund is reflected as a reduction in cost of coal sales.

Retroactive Royalty Rate Adjustments. During 2002, we were notified by the Bureau of Land Management (BLM) that we would receive a royalty rate reduction for certain tons mined at our West Elk location. The rate reduction applies to a specified number of tons beginning October 1, 2001 and ending no later than October 1, 2005. The retroactive portion of the refund totaled $3.3 million and has been recognized as a reduction of cost of coal sales. Additionally, Canyon Fuel was notified by the BLM that it would receive a royalty rate reduction for certain tons mined at its Skyline mine. The rate reduction applies to certain tons mined from September 1, 2001 through September 1, 2006. Our portion of the retroactive refund was $1.1 million, and is reflected as income from equity investments.

Reclamation Adjustments Illinois Properties. During the year ended December 31, 2001, we reduced our reclamation liability resulting in a pre-tax gain of $7.5 million, of which $5.6 million was the result of permit revisions and the ultimate sale of the surface rights at our idle mine properties in Illinois, and $1.9 million was a result of estimate changes. These adjustments are reflected as a component of cost of coal sales.

State Tax Credit. During 2001, we recognized a state tax credit covering prior periods. This amount was recorded as a component of cost of coal sales.

Black Lung Excise Tax Recoveries. During the year ended December 31, 2001, as a result of progress in processing claims associated with the recovery of certain previously paid excise taxes on export sales, we recognized a pre-tax gain of $4.6 million. Of the $4.6 million recognized, $3.1 million represents the interest component of the claim and was recorded as interest income. The remaining $1.5 million was recorded as a reduction in cost of coal sales. The gain stems from an IRS notice during the second quarter of 2000 outlining the procedures for obtaining tax refunds on black lung excise taxes paid by the industry on export sales. The notice was the result of a 1998 federal district court decision that found such taxes to be unconstitutional.

Canyon Fuel Property Tax Recoveries. During 2001, Canyon Fuel, our equity method investment, recognized recoveries of previously paid property taxes. Our share of these recoveries was $2.6 million and is reflected in income from equity investment on the Consolidated Statements of Operations.

West Elk Mine Insurance Recoveries. We idled our West Elk underground mine on January 28, 2000 following the detection of combustion-related gases in a portion of the mine. We recognized a final insurance settlement related to the event during 2001. This amount was reflected as a reduction of cost of coal sales in the Consolidated Statements of Operations.

Year Ended December 31, 2003, Compared to Year Ended December 31, 2002

Summarized operating results for 2003 versus 2002 and additional discussion of the 2003 results are provided below.

Revenues

	Year Ended December 31,		Increase (Decrease)	
	2003	**2002**	**$**	**%**
	(Amounts in thousands, except per ton data)			
Coal sales	$1,435,488	$1,473,558	$(38,070)	(2.6)%
Tons sold	100,634	106,691	(6,057)	(5.7)%
Coal sales realization per ton sold	$ 14.26	$ 13.81	$ 0.45	3.3%

Coal sales. Coal sales revenues decreased in 2003 as compared to 2002 primarily as a result of a decline in sales volume in 2003. Volumes were depressed in large part because our utility customers reduced coal stockpile inventory levels throughout the year. Offsetting the volume decline was an increase in average realization, due primarily to higher pricing on shipments made in 2003 as compared to 2002. We experienced higher pricing in all of our operating basins, as average realizations increased 2.6% in Central Appalachia, 10.4% in the Powder River Basin, and 2.8% in the Western Bituminous region.

Our consolidated coal sales revenues are impacted by the mix of sales among our operating regions, as Central Appalachia coal has higher pricing on a per-ton basis than either of our other operating regions. The comparison of revenues for 2003 and 2002 is relatively unaffected by the mix of sales between our eastern and western operations. During 2003, 29.5% of our tons sold were from eastern sources, as compared to 30.1% in 2002.

Costs and Expenses

	Year Ended December 31,		Increase (Decrease)	
	2003	**2002**	**$**	**%**
	(Amounts in thousands, except per ton data)			
Cost of coal sales	$1,418,362	$1,412,541	$ 5,821	0.4%
Selling, general and administrative expenses	47,295	40,019	7,276	18.2%
Long-term incentive compensation expense	16,217		16,217	N/A
Amortization of coal supply agreements	16,622	22,184	(5,562)	(25.1)%
Other expenses	18,980	30,118	(11,138)	(37.0)%
	$1,517,476	$1,504,862	$ 12,614	0.8%

Cost of coal sales per ton sold	$ 14.09	$ 13.24	$ 0.85	6.4%

Cost of coal sales. Cost of coal sales increased despite a decrease in coal sales due primarily to increased costs related to our pension and postretirement medical plans of $34.0 million. This increase was a result of changes in the actuarial assumptions used to determine the liabilities and expenses related to the plans. Of the $34.0 million increase, $33.5 million related to our Central Appalachian operations. Additionally, cost of coal sales in 2003 was negatively impacted by the charges related to the reduction in force mentioned above and due to disruptions in production resulting from severe weather in the first quarter of 2003 at certain operations.

Regional Analysis:

Central Appalachia Cost of coal sales increased 1.1%, despite a 7.5% decrease in sales volumes. On a per-ton operating cost basis (defined as including all mining costs but excluding pass-through transportation expenses), costs increased 9.3% from $28.26 per ton in 2002 to $30.87 per ton in 2003. As discussed above, Central Appalachia costs were negatively affected by the increased expense resulting from changes in actuarial assumptions related to our pension and postretirement medical plans.

Powder River Basin Cost of coal sales declined 2.0% as sales volumes declined 4.7%. On a per-ton operating cost basis, costs increased slightly to $5.45 in 2003 from $5.31 in 2002. The increase was primarily a result of higher costs for certain operating supplies, including explosives and diesel fuel.

Western Bituminous Region Cost of coal sales increased 2.0% despite a decline in volume of 6.4%, resulting in per-ton operating costs increasing from $14.53 to $15.41. Volumes declined as a result of our utility customers reducing inventory stockpiles throughout the year. As many of our costs are fixed in nature, the reduced volume did not result in reduced overall costs.

Selling, general and administrative expenses. The increase in selling, general and administrative expenses is primarily due to an increase in compensation-related expenses and costs related to the reduction in force mentioned above. Our 2003 administrative expenses include approximately $2.7 million earned under our annual incentive plan. No amounts were earned under the annual incentive plan in 2002.

Amortization of coal supply agreements. Amortization of coal supply agreements declined in 2003 as compared to 2002 primarily as a result of the renegotiation of a significant contract in 2003. In April 2003, we agreed to terms with a customer seeking to buy out of the remaining term of an above-market supply contract. The buyout resulted in the receipt of $52.5 million in cash and the write off of the contract value of approximately $37.5 million. Amortization related to this contract was $0.9 million in 2003 compared to $2.8 million in 2002. Additionally, two other contracts were fully amortized in 2003. Amortization on these contracts totaled $2.5 million in 2003 versus $5.4 million in 2002.

Other expenses. The decrease in other expenses is primarily a result of lower costs to terminate certain contractual obligations for the purchase of coal as compared to the prior year.

Other Operating Income

	Year Ended December 31,		Increase (Decrease)	
	2003	2002	$	%
	(Amounts in thousands)			
Income from equity investments	$ 34,390	$ 10,092	$ 24,298	240.8%
Gain on sale of units of NRP	42,743		42,743	N/A
Other operating income	45,226	50,489	(5,263)	(10.4)%
	$ 122,359	$ 60,581	$ 61,778	102.0%

Income from equity investments. Income from equity investments for 2003 is comprised of $19.7 million from our investment in Canyon Fuel and $14.7 million from our investment in NRP. For 2002, income from Canyon Fuel was $7.8 million and income from NRP was $2.3 million. The improved results from Canyon Fuel are due primarily to improved operating margins, as reduced operating costs more than offset slightly lower realizations. The increase in income from NRP is due to the fact that 2003 includes a full year of income from NRP, while 2002 includes only that period from the formation of NRP in October 2002.

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Other operating income. The decline in other operating income is due primarily to lower outlease royalty income resulting from the contribution of reserves and the related leases to NRP. The royalty income we recorded in 2003 was $7.1 million lower than that reported in 2002. This decline was partially offset by the gains on the sale of land described above.

Interest Expense, Net

	Year Ended December 31,		Increase (Decrease)	
	2003	**2002**	**$**	**%**
	(Amounts in thousands)			
Interest expense	$50,133	$51,922	$(1,789)	(3.4)%
Interest income	(2,636)	(1,083)	(1,553)	(143.4)%
	$47,497	$50,839	$(3,342)	(6.6)%

Interest expense. The decline in interest expense is the result of lower average outstanding borrowings, as average debt levels declined more than 10% in 2003 as compared to 2002. During 2003, we reduced our overall debt levels through a public offering of preferred stock. This decline in debt levels was partially offset by higher interest rates. In June of 2003, we replaced Arch Western s variable-rate term loans with fixed-rate senior notes. The fixed-rate on the senior notes is higher than the variable rates that we paid in 2002.

Other non-operating income and expense

Amounts reported as non-operating consist of income or expense resulting from our financing activities other than interest. As described above, our results of operations for 2003 include expenses of $4.7 million related to debt extinguishment costs and $4.3 million related to the termination of hedge accounting and resulting amortization of amounts that had previously been deferred.

Additionally, we recognized income of $13.4 million from mark-to-market adjustments for interest rate swap agreements which no longer qualify for hedge accounting.

Benefit from income taxes

	Year Ended December 31,		Increase (Decrease)	
	2003	**2002**	**$**	**%**
	(Amounts in thousands)			
Benefit from income taxes	$23,210	$19,000	$4,210	22.2%

Our effective tax rate is sensitive to changes in estimates of annual profitability and percentage depletion. The increase in the income tax benefit for 2003 is primarily due to the utilization of a capital loss which had previously been reserved. We were able to utilize the capital loss to offset a portion of the gain from the sale of units of NRP.

Deferred tax assets and liabilities are recorded at the maximum effective tax rate. Statement of Financial Accounting Standards No. 109 Accounting for Income Taxes 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. We have historically been subject to alternative minimum tax (AMT), and it is more likely than not that we will remain an AMT taxpayer in the foreseeable future. Valuation allowances are established against deferred tax assets so as to value the asset to an amount that is realizable, as further described in Management s Discussion and Analysis of Financial Condition Critical Accounting Policies.

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Net income (loss) before cumulative effect of accounting change

	Year Ended December 31,		Increase (Decrease)	
	2003	2002	$	%
	(Amounts in thousands)			
Net income (loss) before cumulative effect of accounting change	$20,340	$(2,562)	$22,902	N/A

The increase in net income before cumulative effect of accounting change is primarily due to the gain on the sale of units of NRP, offset by the long-term compensation plan expense, each of which is described above.

Cumulative effect of accounting change

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). FAS 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value at the time obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. Application of FAS 143 resulted in a cumulative effect loss as of January 1, 2003 of $3.7 million, net of tax.

Preferred stock dividends

On January 31, 2003, we utilized our Universal Shelf Registration Statement and completed a public offering of 2,875,000 shares of 5% Perpetual Cumulative Convertible Preferred Stock. Dividends on the preferred stock are cumulative and are payable quarterly at the annual rate of 5% of the liquidation preference. Our net income available to common shareholders for the year ending December 31, 2003 reflects $6.6 million of preferred dividends.

Year Ended December 31, 2002, Compared to Year Ended December 31, 2001

Results for the year ended December 31, 2002 were adversely impacted by the state of oversupply in the coal market that resulted from an extremely mild winter in late 2001 and early 2002 and a period of industrial economic weakness that dampened electricity demand. As a result, we reduced our rate of production from planned levels at our mining operations. Offsetting the impact of the overall production cuts was an improvement in operating performance at the West Elk Mine, which had experienced production difficulties and increased costs in 2001 resulting from high methane levels.

Summarized operating results for 2002 versus 2001 and additional discussion of the 2002 results are provided below.

Revenues

	Year Ended December 31,		Increase (Decrease)	
	2002	2001	$	%
	(Amounts in thousands, except per ton data)			
Coal sales	$1,473,558	$1,403,370	$70,188	5.0%
Tons sold	106,691	109,455	(2,764)	(2.5)%
Coal sales realization per ton sold	$ 13.81	$ 12.82	$ 0.99	7.7%

Coal sales. Coal sales revenues increased in 2002 as compared to 2001 primarily as a result of higher pricing on coal shipped during 2002 as compared to 2001 in all of our operating regions. This impact was partially offset by the decline in the number of tons sold. The decline in sales volumes was a result of the state of oversupply in coal markets described above.

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Our consolidated coal sales revenues are impacted by the mix of sales among our operating regions, as Central Appalachian coal has higher pricing on a per-ton basis than coal sourced from our other operating basins. Our average coal sales realization increased in 2002 despite a shift in mix towards western coal. During 2002, 69.9% of our tons sold were from western sources, as compared to 68.9% in 2001.

Costs and Expenses

	Year Ended December 31,		Increase (Decrease)	
	2002	2001	$	%
	(Amounts in thousands, except per ton data)			
Cost of coal sales	$1,412,541	$1,336,218	$76,323	5.7%
Selling, general and administrative expenses	40,019	42,889	(2,870)	(6.7)%
Long-term incentive compensation expense		1,515	(1,515)	(100.0)%
Amortization of coal supply agreements	22,184	27,460	(5,276)	(19.2)%
Other expenses	30,118	18,190	11,928	65.6%
	$1,504,862	$1,426,272	$78,590	5.5%
Cost of coal sales per ton sold	$ 13.24	$ 12.21	$ 1.03	8.4%

Cost of coal sales. The increase in cost of coal sales is primarily due to the increase in coal sales revenues, as certain of our costs (including severance and other production taxes and coal royalties) are incurred as a percentage of coal sales realization. Additionally, 2001 cost of coal sales includes the West Elk insurance recoveries, reclamation adjustments, and state tax credits described above.

Regional Analysis:

Central Appalachia Cost of coal sales increased 7.2% despite a decline in volumes of 5.5%. Operating cost per ton (defined as including all mining costs but excluding pass-through transportation expense) was $28.26 in 2002 as compared to 24.68 in 2001. Costs for 2001 were reduced by the state tax credit and black lung excise tax recoveries described above. Additionally, expenses related to our pension and postretirement medical plans increased $7.2 million in 2002 as compared to 2001.

Powder River Basin Cost of coal sales in 2002 increased less than one percent as compared to 2001, while volumes declined 3.1%. On a per-ton operating cost basis, costs increased 8.3% from $4.90 to $5.31. The increase in per ton costs is a result of our decision to cut back production throughout 2002 in response to the weak coal market environment at that time.

Western Bituminous Sales volumes increased 21.3%, resulting in an increase in cost of coal sales of 13.8%. On a per-ton operating cost basis, costs declined 4.4% from $15.19 to $14.53. Costs during 2001 were negatively affected by production difficulties and increased costs at our West Elk mine caused by high methane levels.

Selling, general and administrative expenses. The decrease in selling, general and administrative expenses is primarily attributable to incentive compensation accruals of $2.7 million recorded during 2001. We did not record any incentive compensation accruals during the year ended December 31, 2002.

Amortization of coal supply agreements. Amortization of coal supply agreements declined $5.3 million primarily as a result of the expiration and buy-out of above-market contracts that were valued as assets on our balance sheet and amortized in 2001.

Other expenses. Other expenses increased in 2002 primarily due to costs incurred to terminate certain contractual obligations for the purchase of coal.

Other Operating Income

	Year Ended December 31,		Increase (Decrease)	
	2002	**2001**	**$**	**%**
	(Amounts in thousands)			
Income from equity investments	$10,092	$26,250	$(16,158)	(61.6)%
Other operating income	50,489	59,108	(8,619)	(14.6)%
	$60,581	$85,358	$(24,777)	(29.0)%

Income from equity investments. In 2002, income from equity investments consisted of $7.8 million from our investment in Canyon Fuel and $2.3 million from our investment in NRP. Income from equity investments in 2001 consisted solely of income from our investment in Canyon Fuel. The decrease in investment income from Canyon Fuel resulted from decreased operating earnings at Canyon Fuel due to the expiration of a favorable sales contract at the end of 2001 and a weak market environment for Utah coal throughout 2002. Additionally, in 2001, Canyon Fuel recognized recoveries of previously paid property taxes, as described above. Income from our equity investment in NRP represents our share of NRP s earnings for the period from October 17, 2002 (the date of the formation of NRP) through November 30, 2002. We account for income from our investment in NRP on a one-month time lag.

Other operating income. The decrease in other operating income was primarily attributable to significant asset sales in 2001 which did not recur in 2002. These asset sales resulted in a pre-tax gain of $13.5 million in 2001, compared to $0.8 million in 2002.

Additionally, royalty income in 2002 from coal reserves leased to third parties declined by approximately $2.9 million, due primarily to the fact that certain of the leased reserves were contributed to NRP as described above. These items were partially offset by income from the settlement of coal contracts described above.

Interest Expense, Net

	Year Ended December 31,		Increase (Decrease)	
	2002	**2001**	**$**	**%**
	(Amounts in thousands)			
Interest expense	$51,922	$64,211	$(12,289)	(19.1)%
Interest income	(1,083)	(4,264)	3,181	74.6%
	$50,839	$59,947	$ (9,108)	(15.2)%

Interest expense. Interest expense decreased by $12.3 million during the year ended December 31, 2002 as a result of lower average debt levels and lower interest rates during 2002 when compared to the prior year. Our average debt levels declined approximately 9% in 2002 as compared to 2001. Additionally, we paid a variable rate of interest on a substantial portion of our borrowings in 2002 and 2001, and 2002 expense benefited from a lower interest rate environment.

Interest income. The decrease in interest income in 2002 is the result of the recognition of the interest component of the black lung excise tax recovery during the year ended December 31, 2001 described previously.

Benefit from income taxes

	Year Ended December 31,		Increase (Decrease)	
	2002	**2001**	**$**	**%**
	(Amounts in thousands)			
Benefit from income taxes	$19,000	$4,700	$14,300	N/A

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Our effective tax rate is sensitive to changes in annual profitability and percentage depletion. The income tax benefit recorded in 2002 is primarily the result of favorable tax settlements and the impact of percentage depletion. During 2002, we received notice from the IRS of proposed adjustments for previous tax years. These adjustments resulted in an increase in the tax benefit of $10.5 million. The benefit resulting from the percentage depletion increased in 2002 as compared to 2001 as a result of the impact of higher coal prices and increased profitability at certain of our mines.

Net income (loss)

	Year Ended December 31,		Increase (Decrease)	
	2002	**2001**	**$**	**%**
	(Amounts in thousands)			
Net income (loss)	$(2,562)	$7,209	$(9,771)	(135.5)%

The decrease in net income is primarily due to the reduction in our income from our equity investment in Canyon Fuel and the decrease in other revenues, as discussed above.

Outlook

Vulcan Acquisition. On May 29, 2003, we entered into an agreement to acquire (1) Vulcan Coal Holdings, L.L.C. (Vulcan), which owns all of the common equity of Triton Coal Company, LLC (Triton), and (2) all of the preferred units of Triton, for a purchase price of $364.0 million, subject to adjustments for working capital. Consummation of the transaction is subject to various conditions, including the receipt by us and by Vulcan of all necessary governmental and regulatory consents and other customary conditions. We intend to finance the acquisition with cash, borrowings under our existing revolving credit facility and a $100 million term loan at our Arch Western subsidiary.

Triton is the nation s seventh largest coal producer and the operator of two mines in the Powder River Basin. These mines, North Rochelle and Buckskin, produced a combined total of 42.2 million tons of coal in 2002 and are supported by approximately 744 million tons of proven and probable reserves. The North Rochelle mine produces 8,800 Btu super-compliance quality coal on a reserve base of approximately 250 million tons. In 2002, North Rochelle produced 23.9 million tons of coal. The Buckskin mine produces 8,400 Btu compliance quality coal on a reserve base of approximately 494 million tons. In 2002, Buckskin produced 18.3 million tons of coal.

On January 30, 2004, we entered into an agreement to sell the Buckskin mine to Peter Kiewit and Sons Inc. for a purchase price of approximately $82.0 million. The completion of the sale of the Buckskin mine is contingent, among other things, on the completion of our acquisition of Triton.

The acquisition of the North Rochelle mine will increase our total reserves in the Powder River Basin by approximately 15%, from 1.6 billion tons to 1.84 billion tons. North Rochelle and Black Thunder are contiguously located, sharing a 5.5-mile property line. We have identified expected synergies, based on Triton s 2002 earnings, of approximately $18 million to $22 million annually that may be realized through the operational integration of Triton s North Rochelle mine and the Black Thunder mine.

We have capitalized the legal and other costs associated with our acquisition of Vulcan as part of its purchase price. In the event the transaction is not consummated, such costs are required to be immediately expensed. As of December 31, 2003, costs associated with the Vulcan acquisition totaled $3.6 million. In addition, whether or not the transaction is consummated, we will be obligated to pay $2.9 million in retention bonuses to key Vulcan employees.

Impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003. On December 8, 2003 President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree heath care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. On January 12, 2004, the Financial

Accounting Standards Board issued FASB Staff Position No. FAS 106-1 (FSP FAS 106-1), which permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Act. We have elected to defer accounting for the Act until 2004. At this time, we are not able to quantify the impact that the Act will have on our postretirement obligations. Additionally, depending on the FASB s final authoritative guidance for accounting for the effects of the Act, we may be required to change our previously reported financial statements.

Production Levels. Our 65% owned Canyon Fuel subsidiary previously announced that its Skyline mine is scheduled to be idled by June 30, 2004 due to water issues at the mine. The Skyline mine produced 2.8 million tons of coal and contributed $5.6 million to our operating income in 2003. Canyon Fuel anticipates increasing production from its other two mines to make up a portion of the scheduled production decrease associated with the idling.

Expenses Related to Interest Rate Swaps. We had designated certain interest rate swaps as hedges of the variable rate interest payments due under Arch Western s term loans. Pursuant to the requirements of FAS 133, historical mark-to-market adjustments related to these swaps through June 25, 2003 of $27.0 million were deferred as a component of Accumulated Other Comprehensive Loss. Subsequent to the repayment of the term loans, these deferred amounts will be amortized as additional expense over the original contractual terms of the swap agreements. As of December 31, 2003, the remaining deferred amounts will be recognized as expense in the following periods: $8.3 million in 2004; $7.7 million in 2005; $4.8 million in 2006; and $1.9 million in 2007.

Chief Objectives. We continue to focus on taking steps to increase stockholder returns by improving earnings, strengthening cash generation, and improving productivity at our large-scale mines, while building on our strategic position in our target coal-producing basins, the Powder River Basin and the Central Appalachian Basin. In addition, we are aggressively pursuing savings in both overhead and operating costs. We instituted personnel cutbacks at our corporate headquarters and Eastern operations in the first half of 2003 and recently initiated a cost reduction effort targeting key cost drivers at each of our captive mines.

Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of our management, including the CEO and CFO, of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2003. Based on that evaluation, our management, including the CEO and CFO, concluded that our disclosure controls and procedures were effective as of such date. There have been no significant changes in our internal controls or in other factors that could significantly affect internal controls subsequent to December 31, 2003.

Liquidity and Capital Resources

The following is a summary of cash provided by or used in each of the indicated types of activities during the past three years:

	Year Ended December 31,		
	2003	2002	2001
	(In thousands)		
Cash provided by (used in):			
Operating activities	$162,361	$ 176,417	$ 145,661
Investing activities	6,832	(128,303)	(129,209)
Financing activities	75,791	(45,447)	(15,590)

Cash provided by operating activities in 2003 declined as compared to 2002 due primarily to lower income levels (after adjusting for gains from the NRP unit sale and other asset sales). Cash provided by operating activities increased in 2002 as compared to 2001 due primarily to reduced requirements for working capital components other than inventories.

Cash provided by investing activities reflects the receipt of $115.0 million from the sale of the subordinated units and general partner interest of NRP and the receipt of $52.5 million from the buyout of a coal supply contract with above-market pricing. These non-recurring cash inflows offset our capital expenditures and advanced royalty payments, which totaled $165.0 million. Cash used in investing activities decreased during 2002 as compared to 2001 due primarily to the impact of the sale of limited partnership units of NRP in 2002, which generated proceeds of $33.6 million. Excluding the proceeds from the sale, cash used in investing activities increased due to higher capital expenditures and reduced proceeds from property dispositions.

Cash provided by financing activities in 2003 reflects the proceeds from the issuance of the Arch Western Finance senior notes (which were used to retire Arch Western s existing debt) and the proceeds from the sale of preferred stock (see additional discussion below). Cash used in financing activities during 2002 primarily represents net payments under our revolver and lines of credit, payments of dividends, and reductions of capital lease obligations. In addition, during 2002, we entered into a sale and leaseback of equipment that resulted in proceeds of $9.2 million. Cash used in financing activities during 2001 reflects the cash generated by the February 2001 and May 2001 issuances of common stock (described below) resulting in proceeds of $372.2 million, the pay-down of $376.9 million of debt and the repurchase of our common stock at a cost of $5.0 million.

On February 22, 2001, we completed a public offering of 9,927,765 shares of common stock, including the remaining 4,756,968 shares held by our then largest stockholder, Ashland Inc., and 5,170,797 primary and treasury shares issued directly by us. Proceeds realized from the transaction, which totaled $92.9 million net of the underwriters discount and expenses, were used to pay down debt.

On April 12, 2001, we filed a Universal Shelf Registration Statement on Form S-3 with the Securities and Exchange Commission. The Universal Shelf allows us to offer, from time to time, an aggregate of up to $750 million in debt securities, preferred stock, depositary shares, common stock and related rights and warrants. On May 8, 2001, we utilized the shelf registration and completed a public offering of 8,500,000 primary shares of common stock. On May 16, 2001, the underwriters involved in the offering purchased an additional 424,200 shares pursuant to an over-allotment option granted by us in connection with the May 8, 2001 offering. The proceeds realized from these transactions after the underwriting discount and expenses were $279.3 million. The proceeds were used to retire our term loan with the remainder used to reduce the borrowings under our revolving credit facility.

On January 31, 2003, we again utilized our Universal Shelf and completed a public offering of 2,875,000 shares of 5% Perpetual Cumulative Convertible Preferred Stock. The net proceeds from the offering of approximately $139.0 million were used to reduce indebtedness under our revolving credit facility and for working capital and general corporate purposes, including potential acquisitions. At December 31, 2003, we had the ability to issue an additional $311.8 million in debt and equity securities under the Universal Shelf.

On September 14, 2001, our Board of Directors approved a stock repurchase plan, under which we may repurchase up to 6.0 million of our shares of common stock from time to time. Through December 31, 2003, we repurchased 357,200 shares of our common stock for $5.0 million pursuant to the plan at an average purchase price of $14.13 per share. The repurchased shares are being held in our treasury. Future repurchases under the plan will be made at management s discretion and will depend on market conditions and other factors.

We generally satisfy our working capital requirements and fund our capital expenditures and debt-service obligations with cash generated from operations. We believe that cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements and anticipated capital expenditures for at least the next several years. Our ability to fund planned capital expenditures, to make acquisitions and to pay dividends will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry, and by financial, business and other factors, some of which are beyond our control.

Capital expenditures were $132.4 million, $137.1 million and $123.4 million for 2003, 2002 and 2001, respectively. Capital expenditures are made to improve and replace existing mining equipment, expand existing mines, develop new mines and improve the overall efficiency of mining operations. We anticipate that capital expenditures during 2004 will be approximately $150 million.

At December 31, 2003, we had $43.9 million in letters of credit outstanding which resulted in $306.1 million of unused capacity under our revolving credit facility. Sufficient unused capacity is currently available to fund all operating needs. Financial covenant requirements may restrict the amount of unused capacity we have available for borrowings and letters of credit.

Financial covenants contained in our revolving credit facility consist of a maximum leverage ratio, a minimum fixed charge ratio and a minimum net worth test. The leverage ratio requires that we not permit the ratio of total indebtedness at the end of any calendar quarter to adjusted EBITDA for the four quarters then ended to exceed a specified amount. The fixed charge coverage ratio requires that we not permit the ratio of our adjusted EBITDA plus lease expense to interest expense for the four quarters then ended to be less than a specified amount. The net worth test requires that we not permit our net worth to be less than a specified amount plus 50% of cumulative net income. We were in compliance with all financial covenants at December 31, 2003.

On June 25, 2003, Arch Western Finance, LLC, a subsidiary of Arch Western, completed the offering of $700 million of senior notes. The proceeds of the offering were primarily used to repay Arch Western s existing term loans. The senior notes bear a fixed rate of interest of 6.75% and are due in full on July 1, 2013. Interest on the senior notes is payable on January 1 and July 1 each year commencing January 1, 2004. The senior notes are guaranteed by Arch Western and certain of Arch Western s subsidiaries and are secured by a security interest in promissory notes we issued to Arch Western evidencing cash loaned to us by Arch Western. The terms of the senior notes contain restrictive covenants that limit Arch Western s ability to, among other things, incur additional debt, sell or transfer assets, and make investments.

At December 31, 2003, debt amounted to $706.4 million, or 51% of capital employed, compared to $747.3 million, or 58% of capital employed, at December 31, 2002. Based on the level of consolidated indebtedness and prevailing interest rates at December 31, 2003, debt service obligations, which include the current maturities of debt and interest expense for 2004, are estimated to be $54 million.

On September 19, 2003, Arch Western established a new term loan facility that provides for a $100 million term loan. The facility is subject to certain conditions of borrowing, including the consummation of our acquisition of Vulcan. Currently, no amount is available to us under the facility. If Arch Western borrows pursuant to the terms of the facility, the term loan will be due in quarterly installments from October 2004 through April 2007.

We periodically establish uncommitted lines of credit with banks. These agreements generally provide for short-term borrowings at market rates. At December 31, 2003, there were $20.0 million of such agreements in effect, of which none were outstanding.

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At December 31, 2003, substantially all of our outstanding debt bore interest at fixed rates.

Additionally, we are exposed to market risk associated with interest rates resulting from our interest rate swap positions. Prior to the June 25, 2003 Arch Western senior notes offering and subsequent repayment of Arch Western s term loans, we utilized interest rate swap agreements to convert the variable-rate interest payments due under the term loans and our revolving credit facility to fixed-rate payments. As of June 25, 2003, we were a party to interest rate swap agreements having a total notional value of $525.0 million. Subsequent to the senior notes offering, we entered into the following transactions impacting our interest rate swap position:

Terminated swaps with a notional value of $250.0 million by paying $6.6 million to the swap counterparties.

Entered into offsetting swap positions with a total notional value of $250.0 million. Under these offsetting positions, we pay a variable rate based on LIBOR and receive a fixed rate. The variable rate, reset dates and maturities of the offsetting swaps match those of certain of our original swap positions. As such, variable amounts paid pursuant to these offsetting positions will equal the variable amounts received under the original swap positions.

After taking into consideration these transactions, as of December 31, 2003, our net interest rate swap position is as follows:

Swaps with a notional value of $25.0 million which are designated as hedges of future interest payments to be made under our revolving credit facility. Under these swaps, we pay a fixed rate of 5.96% (before the credit spread over LIBOR) and receive a variable rate based upon 30-day LIBOR. The remaining term of the swap agreements at December 31, 2003 was 42 months.

Swaps with a total notional value of $500.0 million consisting of offsetting positions of $250.0 million each. Because of the offsetting nature of these positions, we are not exposed to market interest rate risk related to these swaps. Under these swaps, we pay a weighted average fixed rate 5.72% on $250.0 million of notional value and receive a weighted average fixed rate of 2.71% on $250.0 million of notional value. The remaining terms of these swap agreements at December 31, 2003 ranged from 20 to 43 months.

As of December 31, 2003, the fair value of our net interest rate swap position was a liability of $22.5 million.

We are also exposed to commodity price risk related to our purchase of diesel fuel. We enter into forward purchase contracts to reduce volatility in the price of diesel fuel for our operations.

The discussion below presents the sensitivity of the market value of our financial instruments to selected changes in market rates and prices. The range of changes reflects our view of changes that are reasonably possible over a one-year period. Market values are the present value of projected future cash flows based on the market rates and prices chosen. The major accounting policies for these instruments are described in Note 1 to the consolidated financial statements.

At December 31, 2003, our debt portfolio consisted substantially of fixed rate debt. A change in interest rates on the fixed rate debt impacts the net financial instrument position but has no impact on interest incurred or cash flows. The sensitivity analysis related to our fixed rate debt assumes an instantaneous 100-basis-point move in interest rates from their levels at December 31, 2003, with all other variables held constant. A 100-basis-point increase in market interest rates would result in a $46.4 million decrease in the fair value of our fixed rate debt at December 31, 2003.

As it relates to our interest rate swap positions, a change in interest rates impacts the net financial instrument position. A 100-basis point increase in market interest rates would result in a $0.8 million decrease in the fair value of our liability under the interest rate swap positions at December 31, 2003.

Contractual Obligations

The following is a summary of our significant contractual obligations as of December 31, 2003 (in thousands):

	Payments Due by Period			
	2004	2005-2006	2007-2008	After 2008
Long-term debt	$ 6,371	$	$	$ 700,000
Operating leases	11,771	20,500	13,078	6,604
Royalty leases	32,973	67,578	56,920	118,519
Unconditional purchase obligations	262,807	40,190		
Other long-term obligations				23,200
Total contractual cash obligations	$ 313,922	$ 128,268	$ 69,998	$ 848,323

Unconditional purchase obligations represent amounts committed for purchases of materials and supplies, payments for services, purchased coal, and capital expenditures. Other long-term obligations represent our contractual amounts owed in conjunction with our ownership interest in Dominion Terminal Associates as described in Note 21 to the Consolidated Financial Statements.

In addition to the contractual obligations noted above, we expect to make contributions of approximately $13.0 million to our pension plan in 2004. We believe that our on-hand cash balance, cash generated from operations, and availability under our revolving credit facility and other debt facilities will be sufficient to meet these obligations and our requirements for working capital and capital expenditures.

Contingencies

Reclamation

The federal Surface Mining Control and Reclamation Act of 1977 (SMCRA) and similar state statutes require that mine property be restored in accordance with specified standards and an approved reclamation plan. We accrue for the costs of final mine closure reclamation in accordance with the provisions of FAS 143, which was adopted January 1, 2003. These costs relate to reclaiming the pit and support acreage at surface mines and sealing portals at deep mines. Other costs of final mine closure common to surface and underground mining are related to reclaiming refuse and slurry ponds, eliminating sedimentation and drainage control structures, and dismantling or demolishing equipment or buildings used in mining operations. We also accrue for significant reclamation that is completed during the mining process prior to final mine closure. The establishment of the final mine closure reclamation liability is based upon permit requirements and requires various estimates and assumptions, principally associated with costs and productivities.

We review our entire asset retirement obligation periodically and make necessary adjustments, including permit changes and revisions to costs and productivities to reflect current experience. Our management believes it is making adequate provisions for all expected reclamation and other associated costs.

Legal Contingencies

Permit Litigation Matters. A group of local and national environmental organizations filed suit against the U.S. Army Corps of Engineers in the U.S. District Court in Huntington, West Virginia on October 23, 2003. In its complaint, *Ohio Valley Environmental Coalition, et al v. Bullen, et al,* the plaintiffs allege that the Corps has violated its statutory duties arising under the Clean Water Act, the Administrative Procedure Act and the National Environmental Policy Act in issuing the Nationwide 21 (NWP 21) general permit. The plaintiffs allege that the procedural requirements of the three federal statutes identified in their complaint have been violated, and that the Corps may not utilize the mechanism of a nationwide permit to authorize valley fills. Among specific fills identified in the complaint as not meeting the requirements of the NWP 21 are valley fills associated with several of our operating subsidiaries. If the plaintiffs prevail in this litigation, it may delay our receipt of these permits.

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A separate matter involves a surface mining permit issued by the West Virginia Department of Environmental Protection (DEP) to our Coal-Mac subsidiary on September 29, 2003. This permit has been challenged in an administrative proceeding brought by the West Virginia Highlands Conservancy. The appeal alleges that the permit is incomplete and inaccurate, and thereby not in compliance with the DEP s regulations. Specifically, the petition alleges that the proposal to construct a valley fill is inconsistent with a provision of the state regulations known as the buffer zone rule , that the operation has failed to provide for suitable topsoil material for use in its reclamation, and that the state agency failed to evaluate the consequences to the water quality from the alleged discharge of one substance from the mine site. The DEP is required by state law to defend the issuance of the permit. We have filed a notice to intervene in the proceeding. While the outcome of this litigation is subject to various uncertainties, we believe that the permit was validly issued. If the plaintiffs prevail in this proceeding, Coal-Mac may be required to cease mining operations when it exhausts its permitted coal reserves, which is expected to be within three years at current mining rates.

West Virginia Flooding Litigation. We and three of our subsidiaries have been named, among others, in 17 separate complaints filed in the West Virginia Counties of: Wyoming, McDowell, Fayette, Upshur, Kanawha, Raleigh, Boone and Mercer. These cases collectively include approximately 1,780 plaintiffs who are seeking damages for property damage and personal injuries arising out of flooding that occurred in southern West Virginia in July 2001. The plaintiffs have sued coal, timber, railroad and land companies under the theory that mining, construction of haul roads and removal of timber caused natural surface waters to be diverted in an unnatural way, thereby causing damage to the plaintiffs. The West Virginia Supreme Court has ruled that these cases, along with several additional flood damage cases not involving our subsidiaries, be handled pursuant to the Court s Mass Litigation rules. As a result of this ruling, the cases have been transferred to the Circuit Court of Raleigh County in West Virginia to be handled by a panel consisting of three circuit court judges, which has certified certain legal issues back to the West Virginia Supreme Court. Upon resolution of the legal issues by the West Virginia Supreme Court, the panel will, among other things, determine whether the individual cases should be consolidated or returned to their original circuit courts.

While the outcome of this litigation is subject to uncertainties, based on our preliminary evaluation of the issues and the potential impact on us, we believe this matter will be resolved without a material adverse effect on our financial condition or results of operations.

Ark Land Company v. Crown Industries. Ark Land Company, a subsidiary of ours, filed a declaratory judgment action in December 2003 in Mingo County, West Virginia against Crown Industries involving the interpretation of a severance deed under which Ark Land controls the coal and mining rights on property located in the county. In response to such action, Crown Industries filed a counterclaim against Ark Land and third party complaint against us and two of our other subsidiaries, seeking damages for trespass, nuisance and property damage arising out of the exercise of rights under the severance deed on the property by our subsidiaries. The defendant has alleged that our subsidiaries have insufficient rights to haul certain foreign coals across the property without payment of certain wheelage or other fees to defendant. In addition, the defendant has alleged that we and our subsidiaries have violated West Virginia s Standards for Management of Waste Oil and the West Virginia Surface Coal Mining and Reclamation Act by spilling and disposing hydrocarbon wastes on and in the property and by failing to return the property to its approximate original contour.

While the outcome of this litigation is subject to uncertainties, based on our preliminary evaluation of the issues and the potential impact on us, we believe this matter will be resolved without a material adverse effect on our financial condition or results of operations.

We are a party to numerous other claims and lawsuits with respect to various matters. We provide for costs related to contingencies, including environmental matters, when a loss is probable and the amount is reasonably determinable. After conferring with counsel, it is the opinion of management that the ultimate resolution of these claims, to the extent not previously provided for, will not have a material adverse effect on our consolidated financial condition, results of operations or liquidity.

Certain Trends and Uncertainties

Substantial Leverage Covenants

As of December 31, 2003, we had outstanding consolidated indebtedness of $706.4 million, representing approximately 51% of our capital employed. Despite making substantial progress in reducing debt, we continue to have significant debt service obligations, and the terms of our credit agreements limit our flexibility and result in a number of limitations on us. We also have significant lease and royalty obligations. Our ability to satisfy debt service, lease and royalty obligations and to effect any refinancing of our indebtedness will depend upon future operating performance, which will be affected by prevailing economic conditions in the markets that we serve as well as financial, business and other factors, many of which are beyond our control. We may be unable to generate sufficient cash flow from operations and future borrowings, or other financings may be unavailable in an amount sufficient to enable us to fund our debt service, lease and royalty payment obligations or our other liquidity needs.

As of December 31, 2003, after considering the effects of the various covenants in our credit facilities, we have available liquidity of $560.6 million, consisting of cash on hand of $254.5 million and borrowing capacity of $306.1 million. Additional debt financing beyond this amount would not be available to us without the consent of our creditors.

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

Terms of our credit facilities and leases contain financial and other covenants that create limitations on our ability to, among other things, effect acquisitions or dispositions and borrow additional funds, and require us to, among other things, maintain various financial ratios and comply with various other financial covenants. Our failure to comply with such covenants could result in an event of default under these agreements which, if not cured or waived, would enable our lenders to declare amounts borrowed due and payable, or otherwise result in unanticipated costs.

Losses

We reported a net loss of $2.6 million for the year ended December 31, 2002, and $12.0 million for the first nine months of 2003. The losses in 2002 and the first three quarters of 2003 were primarily attributable to our decision to scale back production in response to a weak market environment and increased costs at certain of our operations. The decision to scale back production came after we had prepared most of the operations to maximize production in order to capitalize on higher market prices for coal that we had previously projected for 2002. Therefore, certain costs incurred to maximize production did not result in higher revenues but did increase the cost of coal sales.

Because the coal mining industry is subject to significant regulatory oversight and affected by the possibility of adverse pricing trends or other industry trends beyond our control, we may suffer losses in the future if legal and regulatory rulings, mine idlings and closures, adverse pricing trends or other factors affect our ability to mine and sell coal profitably.

Environmental and Regulatory Factors

The coal mining industry is subject to regulation by federal, state and local authorities on matters such as:

- the discharge of materials into the environment;
- employee health and safety;
- mine permits and other licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- management of materials generated by mining operations;
- surface subsidence from underground mining;
- water pollution;
- legislatively mandated benefits for current and retired coal miners;
- air quality standards;
- protection of wetlands;
- endangered plant and wildlife protection;
- limitations on land use;
- storage of petroleum products and substances that are regarded as hazardous under applicable laws; and
- management of electrical equipment containing polychlorinated biphenyls, or PCBs.

In addition, the electric generating industry, which is the most significant end-user of coal, is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our coal. The possibility exists that new legislation or regulations may be adopted or that the enforcement of existing laws could become more stringent, either of which may have a significant impact on our mining operations or our customers ability to use coal and may require us or our customers to significantly change operations or to incur substantial costs.

While it is not possible to quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. We post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. Compliance with these laws has substantially increased the cost of coal mining for all domestic coal producers.

Clean Air Act. The federal Clean Air Act and similar state and local laws, which regulate emissions into the air, affect coal mining and processing operations primarily through permitting and emissions control requirements. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the emissions from coal-fired industrial boilers and power plants, which are the largest end-users of our coal. These regulations can take a variety of forms, as explained below.

The Clean Air Act imposes obligations on the Environmental Protection Agency, or EPA, and the states to implement regulatory programs that will lead to the attainment and maintenance of EPA-promulgated ambient air quality standards, including standards for sulfur dioxide, particulate matter, nitrogen oxides and ozone. Owners of coal-fired power plants and industrial boilers have been required to expend considerable resources in an effort to comply with these ambient air standards. Significant additional emissions control expenditures will be needed in order to meet the current national ambient air standard for ozone. In particular, coal-fired power plants will be affected by state regulations designed to achieve attainment of the ambient air quality standard for ozone. Ozone is produced by the combination of two precursor pollutants: volatile organic compounds and nitrogen oxides. Nitrogen oxides are a by-product of coal combustion. Accordingly, emissions control requirements for new and expanded coal-fired power plants and industrial boilers will continue to become more demanding in the years ahead.

In July 1997, the EPA adopted more stringent ambient air quality standards for particulate matter and ozone. In a February 2001 decision, the U.S. Supreme Court largely upheld the EPA s position, although it remanded the EPA s ozone implementation policy for further consideration. On remand, the Court of Appeals for the D.C. Circuit affirmed the EPA s adoption of these more stringent ambient air quality standards. As a result of the finalization of these standards, states that are not in attainment for these standards will have to revise their State Implementation Plans to include provisions for the control of ozone precursors and/or particulate matter. Revised State Implementation Plans could require electric power generators to further reduce nitrogen oxide and particulate matter emissions. The potential need to achieve such emissions reductions could result in reduced coal consumption by electric power generators. Thus, future regulations regarding ozone, particulate matter and other pollutants could restrict the market for coal and our development of new mines. This in turn may result in decreased production and a corresponding decrease in our revenues. Although the future scope of these ozone and particulate matter regulations cannot be predicted, future regulations regarding these and other ambient air standards could restrict the market for coal and the development of new mines.

Furthermore, in October 1998, the EPA finalized a rule that will require 19 states in the Eastern United States that have ambient air quality problems to make substantial reductions in nitrogen oxide emissions by the year 2004. To achieve these reductions, many power plants would be required to install additional control measures. The installation of these measures would make it more costly to operate coal-fired power plants and, depending on the requirements of individual state implementation plans, could make coal a less attractive fuel. A number of states have already submitted to EPA revisions of their State Implementation Plans including provisions for reducing nitrogen oxide emissions, and the remaining states that have not revised their Implementation Plans must do so by May 1, 2004.

Along with these regulations addressing ambient air quality, the EPA has initiated a regional haze program designed to protect and to improve visibility at and around National Parks, National Wilderness Areas and International Parks. This program restricts the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas. Moreover, this program may require certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides and particulate matter. By imposing limitations upon the placement and construction of new coal-fired power plants, the EPA s regional haze program could affect the future market for coal.

Additionally, the U.S. Department of Justice, on behalf of the EPA, has filed lawsuits against several investor-owned electric utilities and brought an administrative action against one government-owned electric utility for alleged violations of the Clean Air Act. The EPA claims that these utilities have failed to obtain permits required under the Clean Air Act for alleged major modifications to their power plants. We supply coal to some of the currently affected utilities, and it is possible that other of our customers will be sued. These lawsuits could require the utilities to pay penalties and install pollution control equipment or undertake other emission reduction measures, which could adversely impact their demand for coal.

New regulations concerning the routine maintenance provisions of the New Source Review program were published in October 2003. Fourteen states, the District of Columbia and a number of municipalities filed lawsuits challenging these regulations, and in December the Court stayed the effectiveness of these rules. In January 2004 the EPA Administrator announced that EPA would be taking new enforcement actions against utilities for violations of the existing New Source Review requirements, and shortly thereafter, EPA issued enforcement notices to several electric utility companies.

In January 2004, EPA proposed two new rules pursuant to the Clean Air Act that, once final, may require additional controls and impose more stringent requirements at coal-fired power generation facilities. First, EPA is seeking to lower nickel and mercury emissions at new and existing sources by requiring the use of Maximum Achievable Control Technology (MACT) and by implementing a nationwide cap and trade program. Second, EPA has proposed to require the submission of State Implementation Plans by 29 states and the District of Columbia to include control measures to reduce the emissions of sulfur dioxide and/or nitrogen oxides, pursuant to the 8-hour ozone standard established pursuant to the Clean Air Act. Should either or both of these proposed rules become final, additional costs may be associated with operating coal-fired power generations facilities that may render coal a less attractive fuel source.

Other Clean Air Act programs are also applicable to power plants that use our coal. For example, the acid rain control provisions of Title IV of the Clean Air Act require a reduction of sulfur dioxide emissions from power plants. Because sulfur is a natural component of coal, required sulfur dioxide reductions can affect coal mining operations. Title IV imposes a two phase approach to the implementation of required sulfur dioxide emissions reductions. Phase I, which became effective in 1995, regulated the sulfur dioxide emissions levels from 261 generating units at 110 power plants and targeted the highest sulfur dioxide emitters. Phase II, implemented January 1, 2000, made the regulations more stringent and extended them to additional power plants, including all power plants of greater than 25 megawatt capacity. Affected electric utilities can comply with these requirements by:

burning lower sulfur coal, either exclusively or mixed with higher sulfur coal;

installing pollution control devices such as scrubbers, which reduce the emissions from high sulfur coal;

reducing electricity generating levels; or

purchasing or trading emissions credits.

Specific emissions sources receive these credits, which electric utilities and industrial concerns can trade or sell to allow other units to emit higher levels of sulfur dioxide. Each credit allows its holder to emit one ton of sulfur dioxide.

In addition to emissions control requirements designed to control acid rain and to attain the national ambient air quality standards, the Clean Air Act also imposes standards on sources of hazardous air pollutants. Although these standards have not yet been extended to coal mining operations, the EPA recently announced that it will regulate hazardous air pollutants from coal-fired power plants. Under the Clean Air Act, coal-fired power plants will be required to control hazardous air pollution emissions by no later than 2009. These controls are likely to require significant new improvements in controls by power plant owners. The most prominently targeted pollutant is mercury, although other by-products of coal combustion may be covered by future hazardous air pollutant standards for coal combustion sources.

Other proposed initiatives may have an effect upon coal operations. One such proposal is the Bush Administration s Clear Skies Initiative. As proposed, this initiative is designed to reduce emissions of sulfur dioxide, nitrogen oxides, and mercury from power plants. Other so-called multi-pollutant bills, which could regulate additional air pollutants, have been proposed by various members of Congress. While the details of all of these proposed initiatives vary, there appears to be a movement towards increased regulation of a number of air pollutants. Were such initiatives enacted into law, power plants could choose to shift away from coal as a fuel source to meet these requirements.

Mine Health and Safety Laws. Stringent safety and health standards have been imposed by federal legislation since the adoption of the Mine Safety and Health Act of 1969. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Safety and Health Act of 1969, imposes comprehensive safety and health standards on all mining operations. In addition, as part of the Mine Safety and Health Acts of 1969 and 1977, the Black Lung Act requires payments of benefits by all businesses conducting current mining operations to coal miners with black lung and to some survivors of a miner who dies from this disease.

Surface Mining Control and Reclamation Act. SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of mining activities. In conjunction with mining the property, we are contractually obligated under the terms of our leases to comply with all laws, including SMCRA and equivalent state and local laws. These obligations include reclaiming and restoring the mined areas by grading, shaping, preparing the soil for seeding and by seeding with grasses or planting trees for use as pasture or timberland, as specified in the approved reclamation plan.

SMCRA also requires us to submit a bond or otherwise financially secure the performance of its reclamation obligations. The earliest a reclamation bond can be completely released is five years after reclamation has been achieved. Federal law and some states impose on mine operators the responsibility for repairing the property or compensating the property owners for damage occurring on the surface of the property as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. In addition, the Abandoned Mine Lands Act, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is $0.35 per ton of coal produced from surface mines and $0.15 per ton of coal produced from underground mines.

We also lease some of our coal reserves to third party operators. Under SMCRA, responsibility for unabated violations, unpaid civil penalties and unpaid reclamation fees of independent mine lessees and other third parties could potentially be imputed to other companies that are deemed, according to the regulations, to have owned or controlled the mine operator. Sanctions against the owner or controller are quite severe and can include civil penalties, reclamation fees and reclamation costs. We are not aware of any currently pending or asserted claims against us alleging that we own or control any of our lessees operations.

Framework Convention on Global Climate Change. The United States and more than 160 other nations are signatories to the 1992 Framework Convention on Global Climate Change, commonly known as the Kyoto Protocol, which is intended to limit or capture emissions of greenhouse gases such as carbon dioxide and methane. The U.S. Senate has neither ratified the treaty commitments, which would mandate a reduction in U.S. greenhouse gas emissions, nor enacted any law specifically controlling greenhouse gas emissions, and the Bush Administration has withdrawn support for this treaty. Nonetheless, future regulation of greenhouse gases could occur either pursuant to future U.S. treaty obligations or pursuant to statutory or regulatory changes under the Clean Air Act. Efforts to control greenhouse gas emissions could result in reduced demand for coal if electric power generators switch to lower carbon sources of fuel.

West Virginia Antidegradation Policy. In January 2002, a number of environmental groups and individuals filed suit in the U.S. District Court for the Southern District of West Virginia to challenge the EPA s approval of West Virginia s antidegradation implementation policy. Under the federal Clean Water Act, state regulatory authorities must conduct an antidegradation review before approving permits for the discharge of pollutants to waters that have been designated as high quality by the state. Antidegradation review involves public and intergovernmental scrutiny of permits and requires permittees to demonstrate that the proposed activities are justified in order to accommodate significant economic or social development in the area where the waters are located. The plaintiffs in this lawsuit, *Ohio Valley Environmental Coalition v. Whitman,* challenge provisions in West Virginia s antidegradation implementation policy that exempt current holders of National Pollutant Discharge Elimination System (NPDES) permits and Section 404 permits, among other parties, from the antidegradation review process. We were exempt from antidegradation review under these provisions. In August 2003, the Southern District of West Virginia vacated EPA s approval of West Virginia s antidegradation procedures, and remanded the matter to EPA. The court s decision may delay the issuance or reissuance of Clean Water Act permits to us or cause these permits to be denied, and may increase the costs, time and difficulty associated with obtaining and complying with Clean Water Act permits for surface mining operations.

Comprehensive Environmental Response, Compensation and Liability Act. CERCLA and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on waste generators, site owners and lessees and others regardless of fault or the legality of the original disposal activity. Although the EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could implicate the liability provisions of the statute. Thus, coal mines that we currently own or have previously owned or operated, and sites to which we sent waste materials, may be subject to liability under CERCLA and similar state laws. In particular, we may be liable under CERCLA or similar state laws for the cleanup of hazardous substance contamination at sites where we own surface rights.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, we may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations. Regulations also provide that a mining permit can be refused or revoked if an officer, director or a shareholder with a 10% or greater interest in the entity is affiliated with another entity that has outstanding permit violations. Thus, past or ongoing violations of federal and state mining laws could provide a basis to revoke existing permits and to deny the issuance of additional permits.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including us, must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically we submit the necessary permit applications several months before we plan to begin mining a new area. In our experience, permits generally are approved several months after a completed application is submitted. In the past, we have generally obtained our mining permits without significant delay. However, we cannot be sure that we will not experience difficulty in obtaining mining permits in the future.

Future legislation and administrative regulations may emphasize the protection of the environment and, as a consequence, the activities of mine operators, including us, may be more closely regulated. Legislation and regulations, as well as future interpretations of existing laws, may also require substantial increases in equipment expenditures and operating costs, as well as delays, interruptions or the termination of operations. We cannot predict the possible effect of such regulatory changes.

Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws.

Surety Bonds. Federal and state laws require us to obtain surety bonds to secure payment of certain long-term obligations including mine closure or reclamation costs, federal and state workers compensation costs, coal leases and other miscellaneous obligations. Many of these bonds are renewable on a yearly basis. It has become increasingly difficult for us to secure new surety bonds or renew such bonds without the posting of collateral. In addition, surety bond costs have increased while the market terms of such bonds have generally become more unfavorable.

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

Other Environmental Laws Affecting Us. We are required to comply with numerous other federal, state and local environmental laws in addition to those previously discussed. These additional laws include, for example, the Resource Conservation and Recovery Act, the Safe Drinking Water Act, the Toxic Substance Control Act and the Emergency Planning and Community Right-to-Know Act. We believe that we are in substantial compliance with all applicable environmental laws.

Competition   Excess Industry Capacity

The coal industry is intensely competitive, primarily as a result of the existence of numerous producers in the coal-producing regions in which we operate, and some of our competitors may have greater financial resources. We compete with several major coal producers in the Central Appalachian and Powder River Basin areas. We also compete with a number of smaller producers in those and other market regions. We are also subject to the risk of reduced profitability as a result of excess industry capacity, which results in reduced coal prices.

Electric Industry Factors; Customer Creditworthiness

Demand for coal and the prices that we will be able to obtain for our coal are closely linked to coal consumption patterns of the domestic electric generation industry, which has accounted for approximately 90% of domestic coal consumption in recent years. These coal consumption patterns are influenced by factors beyond our control, including the demand for electricity (which is dependent to a significant extent on summer and winter temperatures); government regulation; technological developments and the location, availability, quality and price of competing sources of coal; other fuels such as natural gas, oil and nuclear; and alternative energy sources such as hydroelectric power. Demand for our low-sulfur coal and the prices that we will be able to obtain for it will also be affected by the price and availability of high-sulfur coal, which can be marketed in tandem with emissions allowances in order to meet federal Clean Air Act requirements. Any reduction in the demand for our coal by the domestic electric generation industry may cause a decline in profitability.

Electric utility deregulation is expected to provide incentives to generators of electricity to minimize their fuel costs and is believed to have caused electric generators to be more aggressive in negotiating prices with coal suppliers. Deregulation may have a negative effect on our profitability to the extent it causes our customers to be more cost-sensitive.

In addition, our ability to receive payment for coal sold and delivered depends on the creditworthiness of our customers. In general, the creditworthiness of our customers has deteriorated. If such trends continue, our acceptable customer base may be limited.

Reliance on and Terms of Long-Term Coal Supply Contracts

During 2003, sales of coal under long-term contracts, which are contracts with a term greater than 12 months, accounted for 83% of our total revenues. The prices for coal shipped under these contracts may be below the current market price for similar type coal at any given time. As a consequence of the substantial volume of our sales which are subject to these long-term agreements, we have less coal available with which to capitalize on stronger coal prices if and when they arise. In addition, because long-term contracts typically allow the customer to elect volume flexibility, our ability to realize the higher prices that may be available in the spot market may be restricted when customers elect to purchase higher volumes under such contracts, or our exposure to market-based pricing may be increased should customers elect to purchase fewer tons. The increasingly short terms of sales contracts and the consequent absence of price adjustment provisions in such contracts also make it more likely that we will not be able to recover inflation related increases in mining costs during the contract term.

Reserve Degradation and Depletion

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs. Replacement reserves may not be available when required or, if available, may not be capable of being mined at costs comparable to those characteristic of the depleting mines. We have in the past acquired and will in the future acquire, coal reserves for our mine portfolio from third parties. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines can also have an adverse effect on operating results that is disproportionate to the percentage of overall production represented by such mines. Mingo Logan s Mountaineer Mine is estimated to exhaust its longwall mineable reserves in 2006. The Mountaineer Mine generated operating income of $26.1 million and $33.7 million in the years ended December 31, 2003 and 2002, respectively.

Potential Fluctuations in Operating Results Factors Routinely Affecting Results of Operations

Our mining operations are inherently subject to changing conditions that can affect levels of production and production costs at particular mines for varying lengths of time and can result in decreases in profitability. Weather conditions, equipment replacement or repair, fuel prices, fires, variations in coal seam thickness, amounts of overburden rock and other natural materials, and other geological conditions have had, and can be expected in the future to have, a significant impact on operating results. A prolonged disruption of production at any of our principal mines, particularly our Mingo Logan operation in West Virginia or Black Thunder mine in Wyoming, would result in a decrease, which could be material, in our revenues and profitability. Other factors affecting the production and sale of our coal that could result in decreases in our profitability include: (i) expiration or termination of, or sales price redeterminations or suspension of deliveries under, coal supply agreements; (ii) disruption or increases in the cost of transportation services; (iii) changes in laws or regulations, including permitting requirements; (iv) litigation; (v) work stoppages or other labor difficulties; (vi) mine worker vacation schedules and related maintenance activities; and (vii) changes in coal market and general economic conditions.

Transportation

The coal industry depends on rail, trucking and barge transportation to deliver shipments of coal to customers, and transportation costs are a significant component of the total cost of supplying coal. Disruption of these transportation services could temporarily impair our ability to supply coal to our customers. Increases in transportation costs, or changes in such costs relative to transportation costs for coal produced by our competitors or for other fuels, could have an adverse effect on our business and results of operations.

Reserves Title

We base our reserve information on geological data assembled and analyzed by our staff which includes various engineers and geologists, and outside firms. The reserve estimates are annually updated to reflect production of coal from the reserves and new drilling or other data received. There are numerous uncertainties inherent in estimating quantities of recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves and net cash flows necessarily depend upon a number of variable factors and assumptions, such as geological and mining conditions which may not be fully identified by available exploration data or may differ from experience in current operations, historical production from the area compared with production from other producing areas, the assumed effects of regulation by governmental agencies, and assumptions concerning coal prices, operating costs, severance and excise taxes, development costs, and reclamation costs, all of which may cause estimates to vary considerably from actual results.

For these reasons, estimates of the economically recoverable quantities attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of net cash flows expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Actual coal tonnage recovered from identified reserve areas or properties, and revenues and expenditures with respect to our reserves, may vary from estimates, and such variances may be material. These estimates thus may not accurately reflect our actual reserves.

We continually seek to expand our operations and coal reserves in the regions in which we operate through acquisitions of businesses and assets. Acquisition transactions involve various inherent risks, such as assessing the value, strengths, weaknesses, contingent and other liabilities, and potential profitability of acquisition or other transaction candidates; the potential loss of key personnel of an acquired business; the ability to achieve identified operating and financial synergies anticipated to result from an acquisition or other transaction; and unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying the acquisition or other transaction. Any one or more of these factors could impair our ability to realize the benefits anticipated to result from the acquisition of businesses or assets.

A significant part of our mining operations are conducted on properties we lease. The loss of any lease could adversely affect our ability to develop the associated reserves. Because title to most of our leased properties and mineral rights is not usually verified until we have made a commitment to develop a property, which may not occur until after we have obtained necessary permits and completed exploration of the property, our right to mine certain of its reserves may be adversely affected if defects in title or boundaries exist. In order to obtain leases or mining contracts to conduct mining operations on property where these defects exist, we have had to, and may in the future have to, incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases or mining contracts for properties containing additional reserves or maintain our leasehold interests in properties on which mining operations are not commenced during the term of the lease.

Certain Contractual Arrangements

Our affiliate, Arch Western Resources, LLC, is the owner of our reserves and mining facilities in the western United States. The agreement under which Arch Western was formed provides that a subsidiary of ours, as the managing member of Arch Western, generally has exclusive power and authority to conduct, manage and control the business of Arch Western. However, consent of BP Amoco, the other member of Arch Western, would generally be required in the event that Arch Western proposes to make a distribution, incur indebtedness, sell properties or merge or consolidate with any other entity if, at such time, Arch Western has a debt rating less favorable than specified ratings with Moody s Investors Service or Standard & Poor s and fails to meet specified indebtedness and interest ratios.

In connection with our June 1, 1998 acquisition of Atlantic Richfield Company s (ARCO) coal operations, we entered into an agreement under which we agreed to indemnify ARCO against specified tax liabilities in the event that these liabilities arise as a result of certain actions taken prior to June 1, 2013, including the sale or other disposition of certain properties of Arch Western, the repurchase of certain equity interests in Arch Western by Arch Western, or the reduction under certain circumstances of indebtedness incurred by Arch Western in connection with the acquisition. ARCO was acquired by BP Amoco in 2000. Depending on the time at which any such indemnification obligation were to arise, it could impact our profitability for the period in which it arises.

The membership interests in Canyon Fuel, which operates three coal mines in Utah (one of which is scheduled to be idled in 2004), are owned 65% by Arch Western and 35% by a subsidiary of ITOCHU Corporation of Japan. The agreement that governs the management and operations of Canyon Fuel provides for a management board to manage its business and affairs. Some major business decisions concerning Canyon Fuel require the vote of 70% of the membership interests and therefore limit our ability to make these decisions. These decisions include admission of additional members; approval of annual business plans; the making of significant capital expenditures; sales of coal below specified prices; agreements between us and any other member; the institution or settlement of litigation; a material change in the nature of Canyon Fuel s business or a material acquisition; the sale or other disposition, including by merger, of assets other than in the ordinary course of business; incurrence of indebtedness; the entering into of leases; and the selection and removal of officers. The Canyon Fuel agreement also contains various restrictions on the transfer of membership interests in Canyon Fuel.

Our Amended and Restated Certificate of Incorporation requires the affirmative vote of the holders of at least two-thirds of outstanding common stock voting thereon to approve a merger or consolidation and certain other fundamental actions involving or affecting control of us. Our Bylaws require the affirmative vote of at least two-thirds of the members of our Board of Directors in order to declare dividends and to authorize certain other actions.

Critical Accounting Policies

Our financial statements are prepared in accordance with accounting principles that are generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities. Management bases its estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Additionally, these estimates and judgments are discussed with our Audit Committee on a periodic basis. Actual results may differ from the estimates used under different assumptions or conditions. Note 1 to the Consolidated Financial Statements provides a description of all significant accounting policies. We believe that of these significant accounting policies, the following may involve a higher degree of judgment or complexity:

Asset Retirement Obligations

Our asset retirement obligations arise from the federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. Significant reclamation activities include reclaiming refuse and slurry ponds, reclaiming the pit and support acreage at surface mines, and sealing portals at deep mines. Reclamation activities that are performed outside of the normal mining process are accounted for as asset retirement obligations in accordance with the provisions of FAS 143. We determine the future cash flows necessary to satisfy our reclamation obligations on a mine-by-mine basis based upon current permit requirements and various estimates and assumptions, including estimates of disturbed acreage, cost estimates, and assumptions regarding productivity. Estimates of disturbed acreage are determined based on approved mining plans and related engineering data. Cost estimates are based upon historical internal or third-party costs, depending on how the work is expected to be performed. Productivity assumptions are based on historical experience with the equipment that is expected to be utilized in the reclamation activities. In accordance with the provisions of FAS 143, we determine the fair value of our asset retirement obligations. In order to determine fair value, we must also estimate a discount rate and third-party margin. Each is discussed further below:

> *Discount rate* FAS 143 requires that asset retirement obligations be recorded at fair value. In accordance with the provisions of FAS 143, we utilize discounted cash flow techniques to estimate the fair value of our obligations. We base our discount rate on the rates of treasury bonds with maturities similar to expected mine lives, adjusted for our credit standing.

> *Third-party margin* FAS 143 requires the measurement of an obligation to be based upon the amount a third-party would demand to assume the obligation. Because we plan to perform a significant amount of the reclamation activities with internal resources, a third-party margin was added to the estimated costs of these activities. This margin was estimated based upon our historical experience with contractors performing certain types of reclamation activities. The inclusion of this margin will result in a recorded obligation that is greater than our estimates of our cost to perform the reclamation activities. If our cost estimates are accurate, the excess of the recorded obligation over the cost incurred to perform the work will be recorded as a gain at the time that reclamation work is completed.

On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, additional costs resulting from accelerated mine closures, and revisions to cost estimates and productivity assumptions, to reflect current experience. At December 31, 2003, we had recorded asset retirement obligation liabilities of $162.7 million, including amounts reported as current. While the precise amount of these future costs cannot be determined with certainty, as of December 31, 2003, we estimate that the aggregate undiscounted cost of final mine closure is approximately $267.2 million.

Employee Benefit Plans

We have non-contributory defined benefit pension plans covering certain of our salaried and non-union hourly employees. Benefits are generally based on the employee s age and compensation. We fund the plans in an amount not less than the minimum statutory funding requirements nor more than the maximum amount that can be deducted for federal income tax purposes. For the years ended December 31, 2003 and 2002, we contributed $18.9 million and $19.2 million into the plan. We account for our defined benefit plans in accordance with FAS 87, *Employer s Accounting for Pensions,* which requires amounts recognized in the financial statements to be determined on an actuarial basis.

The calculation of our net periodic benefit costs (pension expense) and benefit obligation (pension liability) associated with our defined benefit pension plans requires the use of a number of assumptions that we deem to be critical accounting estimates. Changes in these assumptions can result in different pension expense and liability amounts, and actual experience can differ from the assumptions.

The expected long-term rate of return on plan assets is an assumption of the rate of return on plan assets reflecting the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. We establish the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The pension plan s investment targets are 65% equity, 30% fixed income securities and 5% cash. Investments are rebalanced on a periodic basis to stay within these targeted guidelines. The long-term rate of return assumption used to determine pension expense was 9.0% for the years ended December 31, 2003 and 2002, which is less than the plan s actual life-to-date returns and includes the negative returns of 2001 and 2002 as experienced by the markets in general. Any difference between the actual experience and the assumed experience is deferred as an unrecognized actuarial gain or loss and amortized into the future. The impact of lowering the expected long-term rate of return on plan assets from 9% to 8.5% for 2003 would have been an increase to expense of approximately $0.8 million.

The discount rate represents our estimate of the interest rate at which pension benefits could be effectively settled. Assumed discount rates are used in the measurement of the projected, accumulated and vested benefit obligations and the service and interest cost components of the net periodic pension cost. In estimating that rate, Statement No. 87 requires rates of return on high quality, fixed income investments. We utilize a bond portfolio model that includes bonds that are rated AA or higher with maturities that match the expected benefit payments under the plan. The discount rates used to determine pension expense for 2003 and 2002 were 7.0% and 7.5%, respectively. The impact of lowering the discount rate from the 7.0% utilized in 2003 to an assumed 6.5% would have resulted in an approximate $1.3 million increase in expense in 2003.

The differences generated in changes in assumed discount rates and returns on plan assets are amortized into earnings over a five-year period.

For the measurement of our year-end pension obligation for 2003 (and pension expense for 2004), we changed our long-term rate of return assumption to 8.5% and its discount rate to 6.5%.

We also currently provides certain postretirement medical/life insurance coverage for eligible employees. Generally, covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. The salaried employee postretirement medical/ life plans are contributory, with retiree contributions adjusted periodically, and contain other cost-sharing features such as deductibles and coinsurance. The postretirement medical plan for retirees who were members of the United Mine Workers of America is not contributory. Our current funding policy is to fund the cost of all postretirement medical/ life insurance benefits as they are paid. We account for our other postretirement benefits in accordance with FAS 106, *Employer s Accounting for Postretirement Benefits Other Than Pensions,* which requires amounts recognized in the financial statements to be determined on an actuarial basis.

Various actuarial assumptions are required to determine the amounts reported as obligations and costs related to the postretirement benefit plan. These assumptions include the discount rate and the future medical cost trend rate.

The discount rate assumption reflects the rates available on high-quality fixed-income debt instruments at year-end and is calculated in the same manner as discussed above for the pension plan. The discount rate used to calculate the postretirement benefit expense for 2003 and 2002 was 7.0% and 7.5%, respectively. Had the discount rate been lowered from 7.0% to 6.5% in 2003, we would have incurred additional expense of $8.6 million.

Future medical trend rate represents the rate at which medical costs are expected to increase over the life of the plan. The health care cost trend rate is determined based upon our historical changes in health care costs as well as external data regarding such costs. We have implemented many effective programs that have resulted in actual increases in medical costs to fall far below the double-digit increases experienced by most companies in recent years. The postretirement expense in 2003 was based on an assumed medical inflationary rate of 7.5%, trending down in half percent increments to 5%, which represents the ultimate inflationary rate for the remainder of the plan life. This assumption was based on our then current three-year historical average of per capita increases in health care costs. If we had utilized a medical trend rate of 8% in 2003, we would have incurred $5.4 million of additional expense.

For the measurement of our year-end other postretirement obligation for 2003 (and other postretirement expense for 2004), we changed our medical inflationary rate assumption to 8.0% (trending down to 5%) and our discount rate to 6.5%.

Income Taxes

We record deferred tax assets and liabilities using enacted tax rates for the effect of temporary differences between the book and tax bases of assets and liabilities. A valuation allowance is recorded to reflect the expected future tax benefits to be realized. In determining the appropriate valuation allowance, we take into account the level of expected future taxable income and available tax planning strategies. If future taxable income was lower than expected or if expected tax planning strategies were not available as anticipated, we may record additional valuation allowance through income tax expense in the period such determination was made.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Reference is made to Part II, Item 7 of this Annual Report on Form 10-K for the information required by Item 7A.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Consolidated financial statements of Arch Coal, Inc. and subsidiaries and related notes thereto and report of independent auditors follow.

INDEX TO FINANCIAL STATEMENTS OF ARCH COAL, INC. AND SUBSIDIARIES

REPORT OF INDEPENDENT AUDITORS

To the Stockholders and Board of Directors
Arch Coal, Inc.

We have audited the accompanying consolidated balance sheets of Arch Coal, Inc. and subsidiaries as of December 31, 2003 and 2002 and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the 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 (appearing on pages II-31 to II-68 of this annual report) present fairly, in all material respects, the consolidated financial position of Arch Coal, Inc. and subsidiaries at December 31, 2003 and 2002, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations effective January 1, 2003.

/s/ ERNST & YOUNG LLP
Ernst & Young LLP

St. Louis, Missouri
January 23, 2004

REPORT OF MANAGEMENT

The management of Arch Coal, Inc. is responsible for the preparation of the consolidated financial statements and related financial information in this annual report. The financial statements are prepared in accordance with accounting principles generally accepted in the United States and necessarily include some amounts that are based on management s informed estimates and judgments, with appropriate consideration given to materiality.

The Company maintains a system of internal accounting controls designed to provide reasonable assurance that financial records are reliable for purposes of preparing financial statements and that assets are properly accounted for and safeguarded. The concept of reasonable assurance is based on the recognition that the cost of a system of internal accounting controls should not exceed the value of the benefits derived. The Company has a professional staff of internal auditors who monitor compliance with and assess the effectiveness of the system of internal accounting controls.

The Audit Committee of the Board of Directors, composed of directors who are free from relationships that may impair their independence from Arch Coal, Inc., meets regularly with management, the internal auditors, and the independent auditors to discuss matters relating to financial reporting, internal accounting control, and the nature, extent and results of the audit effort. The independent auditors and internal auditors have full and free access to the Audit Committee, with and without management present.

/s/ STEVEN F. LEER	/s/ ROBERT J. MESSEY
Steven F. Leer *President and Chief Executive Officer*	Robert J. Messey *Senior Vice President and Chief Financial Officer*

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2003	2002	2001
	(In thousands of dollars except per share data)		
REVENUES			
Coal sales	$1,435,488	$1,473,558	$1,403,370
COSTS AND EXPENSES			
Cost of coal sales	1,418,362	1,412,541	1,336,218
Selling, general and administrative expenses	47,295	40,019	42,889
Long-term incentive compensation expense	16,217		1,515
Amortization of coal supply agreements	16,622	22,184	27,460
Other expenses	18,980	30,118	18,190
	1,517,476	1,504,862	1,426,272
OTHER OPERATING INCOME			
Income from equity investments	34,390	10,092	26,250
Gain on sale of units of Natural Resource Partners, LP	42,743		
Other operating income	45,226	50,489	59,108
	122,359	60,581	85,358
Income from operations	40,371	29,277	62,456
Interest expense, net:			
Interest expense	(50,133)	(51,922)	(64,211)
Interest income	2,636	1,083	4,264
	(47,497)	(50,839)	(59,947)
Other non-operating income (expense):			
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps	(8,955)		
Other non-operating income	13,211		
	4,256		
Income (loss) before income taxes and cumulative effect of accounting change	(2,870)	(21,562)	2,509
Benefit from income taxes	(23,210)	(19,000)	(4,700)
Income (loss) before cumulative effect of accounting change	20,340	(2,562)	7,209
Cumulative effect of accounting change, net of taxes	(3,654)		
NET INCOME (LOSS)	$ 16,686	$ (2,562)	$ 7,209
Preferred stock dividends	(6,589)		
Net income (loss) available to common shareholders	$ 10,097	$ (2,562)	$ 7,209
EARNINGS PER COMMON SHARE			

Basic and diluted earnings (loss) before cumulative effect of accounting change	0.26	(0.05)	0.15
Cumulative effect of accounting change	(0.07)		
Basic and diluted earnings (loss) per common share	$ 0.19	$ (0.05)	$ 0.15

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(In thousands of dollars except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 254,541	$ 9,557
Trade accounts receivable	118,376	135,903
Other receivables	29,897	30,927
Inventories	69,907	66,799
Prepaid royalties	4,586	4,971
Deferred income taxes	19,700	27,775
Other	16,638	15,781
Total current assets	513,645	291,713
Coal lands, net	51,390	28,636
Plant and equipment, net	413,840	442,199
Deferred mine development, net	156,564	81,885
Mineral lease rights, net	693,341	732,248
Other assets		
Prepaid royalties	70,880	51,078
Coal supply agreements	6,397	59,240
Deferred income taxes	246,024	221,116
Equity investments	172,045	231,551
Other	63,523	43,142
Total other assets	558,869	606,127
Total assets	$2,387,649	$2,182,808
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable	$ 89,975	$ 113,527
Accrued expenses	180,314	133,287
Current portion of debt	6,349	7,100
Total current liabilities	276,638	253,914
Long-term debt	700,022	740,242
Accrued postretirement benefits other than pension	352,097	324,539
Asset retirement obligations	143,545	117,804
Accrued workers compensation	77,672	80,985
Other noncurrent liabilities	149,640	130,461
Total liabilities	1,699,614	1,647,945
Stockholders equity		
Preferred stock, $.01 par value, $50 liquidation preference, authorized 10,000,000 shares, issued 2,875,000 and 0 shares	29	
Common stock, $.01 par value, authorized 100,000,000 shares, issued 53,561,979 and 52,791,370 shares	536	527
Paid-in capital	988,476	835,763

Retained deficit	(255,936)	(253,943)
Less treasury stock, at cost, 357,200 shares	(5,047)	(5,047)
Accumulated other comprehensive loss	(40,023)	(42,437)
Total stockholders equity	688,035	534,863
Total liabilities and stockholders equity	$2,387,649	$2,182,808

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

Three Years Ended December 31, 2003

	Common Stock	Preferred Stock	Paid-In Capital	Retained Earnings (Deficit)	Treasury Stock at Cost	Accumulated Other Comprehensive Loss	Total
	(In thousands of dollars except share and per share data)						
BALANCE AT JANUARY 1, 2001	$397	$	$473,428	$(234,980)	$(18,971)	$	$219,874
Comprehensive income							
Net income				7,209			7,209
Minimum pension liability adjustment						(2,851)	(2,851)
Unrealized losses on derivatives						(17,978)	(17,978)
Total comprehensive loss							(13,620)
Dividends paid ($.23 per share)				(11,565)			(11,565)
Issuance of 14,094,997 shares of common stock (including 1,541,146 shares held in treasury) pursuant to public offerings	126		353,088		18,971		372,185
Issuance of 441,732 shares of common stock under the stock incentive plan	4		8,911				8,915
Treasury stock purchases of 357,200 shares of common stock					(5,047)		(5,047)
BALANCE AT DECEMBER 31, 2001.	527		835,427	(239,336)	(5,047)	(20,829)	570,742
Comprehensive income							
Net loss				(2,562)			(2,562)
Minimum pension liability adjustment						(16,416)	(16,416)
Unrealized losses on derivatives						(5,192)	(5,192)
Total comprehensive loss							(24,170)
Dividends paid ($.23 per share)				(12,045)			(12,045)
Issuance of 81,454 shares of common stock under the stock incentive plan			336				336
BALANCE AT DECEMBER 31, 2002.	527		835,763	(253,943)	(5,047)	(42,437)	534,863
Comprehensive income							
Net income				16,686			16,686
Minimum pension liability adjustment						3,403	3,403
Unrealized losses on derivatives						(5,940)	(5,940)
Net amount reclassified to income						4,951	4,951
Total comprehensive income							19,100

Dividends							
Common ($.23 per share)				(12,090)			(12,090)
Preferred ($2.29 per share)				(6,589)			(6,589)
Issuance of 2,875,000 shares of perpetual cumulative convertible preferred stock		29	138,995				139,024
Issuance of 770,609 shares of common stock under the stock incentive plan	9		13,718				13,727
BALANCE AT DECEMBER 31, 2003.	$536	$ 29	$988,476	$(255,936)	$ (5,047)	$(40,023)	$688,035

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2003	2002	2001
	(In thousands of dollars)		
OPERATING ACTIVITIES			
Net income (loss)	$ 16,686	$ (2,562)	$ 7,209
Adjustments to reconcile to cash provided by operating activities:			
Depreciation, depletion and amortization	158,464	174,752	177,504
Prepaid royalties expensed	13,153	8,503	7,274
Accretion on asset retirement obligations	12,999		
Gain on sale of units of Natural Resource Partners, LP	(42,743)		
Net gain on disposition of assets	(3,782)	(751)	(14,627)
Income from equity investments	(34,390)	(10,092)	(26,250)
Net distributions from equity investments	49,686	17,121	42,219
Cumulative effect of accounting change	3,654		
Other non-operating (income) expense	(4,256)		
Changes in operating assets and liabilities (see Note 22)	(375)	(4,634)	(46,950)
Other	(6,735)	(5,920)	(718)
Cash provided by operating activities	162,361	176,417	145,661
INVESTING ACTIVITIES			
Capital expenditures	(132,427)	(137,089)	(123,414)
Proceeds from sale of units of Natural Resource Partners, LP	115,000	33,603	
Proceeds from coal supply agreements	52,548		
Additions to prepaid royalties	(32,571)	(27,339)	(24,725)
Proceeds from disposition of capital assets	4,282	2,522	18,930
Cash provided by (used in) investing activities	6,832	(128,303)	(129,209)
FINANCING ACTIVITIES			
Payments on revolver and lines of credit	(65,971)	(26,513)	(241,940)
Net payments on term loans	(675,000)		
Proceeds from issuance of senior notes	700,000		
Debt financing costs	(18,508)	(8,228)	
Proceeds from sale and leaseback of equipment			9,213
Reductions of obligations under capital lease			(8,210)
Dividends paid	(17,481)	(12,045)	(11,565)
Proceeds from issuance of preferred stock	139,024		
Proceeds from sale of common stock	13,727	336	381,100
Purchases of treasury stock			
Cash provided by (used in) financing activities	75,791	(45,447)	(15,590)
Increase in cash and cash equivalents	244,984	2,667	862
Cash and cash equivalents, beginning of year	9,557	6,890	6,028
Cash and cash equivalents, end of year	$ 254,541	$ 9,557	$ 6,890

SUPPLEMENTAL CASH FLOW INFORMATION:

Cash paid during the year for interest	$ 30,014	$ 51,695	$ 71,612
Cash received during the year for income tax refunds	$ (6,407)	$ (3,115)	$ (5,548)

The accompanying notes are an integral part of the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(In Thousands of Dollars Except Per Share Data)

1. Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of Arch Coal, Inc. and its subsidiaries (the Company), which operate in the coal mining industry. The Company s primary business is the production of steam and metallurgical coal from surface and deep mines throughout the United States, for sale to utility, industrial and export markets. The Company s mines are primarily located in the Central Appalachian and western regions of the United States. All subsidiaries (except as noted below) are wholly owned. Intercompany transactions and accounts have been eliminated in consolidation.

The Company s Wyoming, Colorado and Utah coal operations are included in a joint venture named Arch Western Resources, LLC (Arch Western). Arch Western is 99% owned by the Company and 1% owned by BP Amoco. The Company also acts as the managing member of Arch Western.

The membership interests in Canyon Fuel Company, LLC (Canyon Fuel) are owned 65% by the Company and 35% by a subsidiary of ITOCHU Corporation, a Japanese corporation. The agreement which governs the management and operations of Canyon Fuel provides for a Management Board to manage its business and affairs. Generally, the Management Board acts by affirmative vote of the representatives of the members holding more than 50% of the membership interests. However, significant participation rights require either the unanimous approval of the members or the approval of representatives of members holding more than 70% of the membership interests. Those matters which are considered significant participation rights include the following:

- approval of the annual business plan;
- approval of significant capital expenditures;
- approval of significant coal sales contracts;
- approval of the institution of, or the settlement of litigation;
- approval of incurrence of indebtedness;
- approval of significant mineral reserve leases;
- selection and removal of the CEO, CFO, or General Counsel;
- approval of any material change in the business of Canyon Fuel;
- approval of any disposition whether by sale, exchange, merger, consolidation, license or otherwise, and whether directly or indirectly, of all or any portion of the assets of Canyon Fuel other than in the ordinary course of business; and
- approval of request that a member provide additional services to Canyon Fuel.

The Canyon Fuel agreement also contains various restrictions on the transfer of membership interests in Canyon Fuel. As a result of these super-majority voting rights, the Company s 65% ownership of Canyon Fuel is accounted for on the equity method in the consolidated financial statements. Income from Canyon Fuel is reflected in the Consolidated Statements of Operations as income from equity investments. (See additional discussion in Equity Investments in Note 5.)

As of December 31, 2003 and 2002, the Company held limited partnership interest in Natural Resource Partners, LP (NRP) of 12.5% and 34%, respectively. The Company s investment in NRP is accounted for on the equity method in the consolidated financial statements. (See additional discussion in Equity Investments in Note 5.)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company s 17.5% partnership interest in Dominion Terminal Associates is accounted for on the equity method in the consolidated balance sheets. Allocable costs of the partnership for coal loading and storage are included in other expenses in the consolidated statements of operations. (See additional discussion in Commitments and Contingencies in Note 21.)

Accounting Estimates

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

Accounting Change

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). FAS 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value at the time the obligations are incurred. Upon initial recognition of a liability, the cost should also be capitalized as part of the carrying amount of the related long-lived asset and allocated to expense over the useful life of the asset. Previously, the Company accrued for the expected costs of these obligations over the estimated useful mining life of the property. See additional discussion in Note 12, Asset Retirement Obligations.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost. Cash equivalents consist of highly liquid investments with an original maturity of three months or less when purchased.

Allowance for Uncollectible Receivables

The Company maintains allowances to reflect the expected uncollectability of its trade accounts receivable and other receivables based on past collection history, the economic environment and specified risks identified in the receivables portfolio. Allowances recorded at December 31, 2003 and 2002 were $1.5 million and $3.9 million, respectively.

Inventories

Inventories consist of the following:

	December 31,	
	2003	**2002**
Coal	$38,249	$35,039
Supplies, net of allowance	31,658	31,760
	$69,907	$66,799

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs and operating overhead. The Company has recorded a valuation allowance for slow-moving and obsolete supplies inventories of $18.8 million and $17.5 million at December 31, 2003 and 2002, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Coal Acquisition Costs and Prepaid Royalties

The costs to obtain coal lease rights are capitalized and amortized primarily by the units-of-production method over the estimated recoverable reserves. Amortization occurs either as the Company mines on the property or as others mine on the property through subleasing transactions.

Rights to leased coal lands are often acquired through royalty payments. Where royalty payments represent prepayments recoupable against production, they are capitalized, and amounts expected to be recouped within one year are classified as a current asset. As mining occurs on these leases, the prepayment is charged to cost of coal sales.

Coal Supply Agreements

Acquisition costs allocated to coal supply agreements (sales contracts) are capitalized and amortized on the basis of coal to be shipped over the term of the contract. Value is allocated to coal supply agreements based on discounted cash flows attributable to the difference between the above-market contract price and the then-prevailing market price. Accumulated amortization for sales contracts was $204.6 million and $191.0 million at December 31, 2003 and 2002, respectively.

During 2003, the Company agreed to terms with a large customer seeking to buy out of the remaining term of an above-market coal supply contract. The buy-out resulted in the receipt of $52.5 million in cash during the quarter. The Company wrote off the remaining contract value of $37.5 million and recorded a deferred gain of approximately $15 million related to this transaction. The deferred gain will be recognized ratably through 2012.

Exploration Costs

Costs related to locating coal deposits and determining the economic mineability of such deposits are expensed as incurred.

Plant and Equipment

Plant and equipment are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. Expenditures which extend the useful lives of existing plant and equipment or increase the productivity of the asset are capitalized. Plant and equipment are depreciated principally on the straight-line method over the estimated useful lives of the assets, which range from three to 30 years except for preparation plants and loadouts. Preparation plants and loadouts are depreciated using the units-of-production method over the estimated recoverable reserves, subject to a minimum level of depreciation.

Leased plant and equipment meeting certain criteria is capitalized and the present value of the related lease payments is recorded as a liability. Amortization of capitalized leased assets is computed on the straight-line method over the term of the lease.

Accumulated depreciation for plant and equipment was $676.9 million and $606.4 million at December 31, 2003 and 2002, respectively.

Deferred Mine Development

Costs of developing new mines or significantly expanding the capacity of existing mines are capitalized and amortized using the units-of-production method over the estimated recoverable reserves that are associated with the property being benefited. Additionally, the asset retirement obligation asset has been recorded as a component of deferred mine development. Accumulated amortization for deferred development was $128.6 million and $78.0 million at December 31, 2003 and 2002, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Asset Impairment

If facts and circumstances suggest that a long-lived asset may be impaired, the carrying value is reviewed. If this review indicates that the value of the asset will not be recoverable, as determined based on projected undiscounted cash flows related to the asset over its remaining life, then the carrying value of the asset is reduced to its estimated fair value.

Revenue Recognition

Coal sales revenues include sales to customers of coal produced at Company operations and coal purchased from other companies. The Company recognizes revenue from coal sales at the time title passes to the customer. Transportation costs that are billed by the Company and reimbursed to the transportation provider (pass through costs) are included in coal sales and cost of coal sales.

Other Operating Income

Other operating income reflects income from sources other than coal sales, including administration and production fees from Canyon Fuel, royalties earned from properties leased to third parties, and gains and losses from dispositions of long-term assets. These amounts are recognized as services are performed or otherwise earned.

Derivative Financial Instruments

The Company adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (FAS 133), on January 1, 2001. FAS 133 requires all derivative financial instruments to be reported on the balance sheet at fair value. Changes in fair value are recognized either in earnings or equity, depending on the nature of the underlying exposure being hedged and how effective the derivatives are at offsetting price movements in the underlying exposure. The Company does not enter into derivative instruments that do not qualify as hedges, except where derivative instruments are acquired to offset the future effects of an instrument formerly used as a hedge, when that instrument is declared to no longer be a hedge.

The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives for undertaking various hedge transactions. The Company evaluates the effectiveness of its hedging relationships both at the hedge inception and on an ongoing basis. Any ineffectiveness is recorded in the Consolidated Statements of Operations. Ineffectiveness for the years ended December 31, 2003 and 2002 was $0.4 million and $0.8 million, respectively.

The Company has historically utilized interest-rate swap agreements to modify the interest characteristics of outstanding Company debt. The swap agreements essentially convert variable-rate debt to fixed-rate debt. These agreements require the exchange of amounts based on variable interest rates for amounts based on fixed interest rates over the life of the agreement. The Company accrues amounts to be paid or received under interest-rate swap agreements over the lives of the agreements. Such amounts are recognized as adjustments to interest expense over the lives of agreements, thereby adjusting the effective interest rate on the Company s debt.

During 2003, the Company repaid its variable-rate term loans with the proceeds from the sale of fixed-rate notes (see Note 9 Debt and Financing Arrangements). At that time, the Company determined that certain interest rate swaps that had been designated as hedges of the variable-rate interest payments were no longer effective hedges. Historical mark-to-market losses related to these swaps totaling $27.0 million had been previously deferred and will now be amortized as additional expense over the contractual terms of the swap agreements. The swap agreements contractual termination dates range from September 2005 through October 2007. The Company recognized expense of $4.3 million related to these swaps in 2003. Such amount

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

is included in expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps in the accompanying Consolidated Statements of Operations.

Changes in the market value of the interest-rate swaps that no longer qualify as hedges are recorded as income or expense in the period of the change. During 2003, the Company recorded gains of $13.4 million resulting from changes in the market value of interest-rate swaps. This amount is included as other non-operating income in the accompanying Consolidated Statements of Operations.

Income Taxes

Deferred income taxes are based on temporary differences between the financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates for years during which taxes are expected to be paid or recovered.

Stock-Based Compensation

These financial statements include the disclosure requirements of Financial Accounting Standards Board Statement No. 123, *Accounting for Stock-Based Compensation* (FAS 123), as amended by Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* (FAS 148). With respect to accounting for its stock options, as permitted under FAS 123, the Company has retained the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25 (APB 25), *Accounting for Stock Issued to Employees,* and related Interpretations. Had compensation expense for stock option grants been determined based on the fair value at the grant dates consistent with the method of FAS 123, the Company s net income (loss) and earnings (loss) per common share would have been changed to the pro forma amounts as indicated in the following table:

	Year Ended December 31		
	2003	2002	2001
As reported			
Net income (loss) available to common shareholders	$10,097	$ (2,562)	$7,209
Basic and diluted earnings (loss) per share	0.19	(0.05)	0.15
Pro forma (unaudited)			
Net income (loss) available to common shareholders	$ 858	$(11,168)	$3,381
Basic and diluted earnings (loss) per share	0.02	(0.21)	0.07

Recent Accounting Pronouncements

In December 2003, the financial Accounting Standards Board issued a revised Interpretation No. 46, *Consolidation of Variable Interest Entities.* The interpretation clarifies the application of Accounting Research Bulletin No. 51, *Consolidated Financial Statements,* to certain types of entities. The Company does not expect the adoption of this interpretation to have a material impact on its financial statements.

Reclassifications

Certain amounts in the prior years financial statements have been reclassified to conform with the classifications in the current year s financial statements with no effect on previously reported net income or stockholders equity.

2. Changes in Estimates and Other Non-Recurring Revenues and Expenses

During the year ending December 31, 2003, the Company instituted cost reduction efforts throughout its operations. These cost reduction efforts included the termination of approximately 100 employees at the Company s corporate headquarters and its eastern mining operations and the recognition of expenses related to

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

severance of $2.6 million. Of this amount, $1.6 million was reported as a component of cost of coal sales, with the remainder reported in selling, general and administrative expenses. Substantially all of the amounts noted were paid during 2003.

During the year ended December 31, 2003, the Company was notified by the State of Wyoming of a favorable ruling as it relates to the Company s calculation of coal severance taxes. The ruling resulted in a refund of previously paid taxes and the reversal of previously accrued taxes payable. The impact on the 2003 financial results was a gain of $2.5 million, which was reflected as a reduction of cost of coal sales.

The Company recognized income of $1.6 million during 2003 resulting from the collection of receivables which had previously been estimated to be uncollectible and had been fully reserved in prior periods.

During 2003, the Company received $1.4 million from a customer that did not meet its contractual purchase requirements. This amount has been recorded as other operating income in the accompanying Condensed Consolidated Statements of Operations.

During the year ended December 31, 2002, the Company settled certain coal contracts with a customer that was partially unwinding its coal supply position and desired to buy out of the remaining terms of those contracts. The settlements resulted in a pre-tax gain of $5.6 million, which was recognized in other operating income in the Consolidated Statements of Operations.

The Company recognized a pre-tax gain of $4.6 million during the year ended December 31, 2002 as a result of a workers compensation premium adjustment refund from the State of West Virginia. During 1998, the Company entered into the West Virginia workers compensation plan at one of its subsidiary operations. The subsidiary paid standard base rates until the West Virginia Division of Workers Compensation could determine the actual rates based on claims experience. Upon review, the Division of Workers Compensation refunded $4.6 million in premiums, which was recognized as an adjustment to cost of coal sales in the Consolidated Statements of Operations.

During the year ended December 31, 2002, the Company was notified by the Bureau of Land Management (BLM) that it would receive a royalty rate reduction for certain tons mined at its West Elk location. The rate reduction applies to a specified number of tons beginning October 1, 2001 and ending no later than October 1, 2005. The retroactive portion of the refund totaled $3.3 million and was recognized in 2002 as a reduction of cost of coal sales in the Consolidated Statements of Operations. Additionally, Canyon Fuel was notified by the BLM that it would receive a royalty rate reduction for certain tons mined at its Skyline mine. The rate reduction applies to certain tons mined from September 1, 2001 through September 1, 2006. The Company s portion of the retroactive refund was $1.1 million, and was reflected in 2002 as income from equity investments in the Consolidated Statements of Operations.

The Company s operating results for the year ended December 31, 2001, reflect a $9.4 million insurance settlement as part of the Company s coverage under its property and business interruption policy. The insurance settlement represents the final settlement for losses incurred at the West Elk mine in Gunnison County, Colorado, which was idled from January 28, 2000 to July 12, 2000 following the detection of combustion-related gases. The amount is reflected as a reduction of cost of coal sales.

During the year ended December 31, 2001, the Company reduced its reclamation liability resulting in a pre-tax gain of $7.5 million, of which $5.6 million resulted from permit revisions and the ultimate sale of the surface rights at its idle mine properties in Illinois, and $1.9 million resulted from estimate changes.

During the year ended December 31, 2001, as a result of progress in processing claims associated with the recovery of certain previously paid excise taxes on export sales, the Company recognized a pre-tax gain of $4.6 million. Of the $4.6 million recognized, $3.1 million represented the interest component of the claim and was recorded as interest income. The gain stems from an IRS notice during the second quarter of 2000 outlining the procedures for obtaining tax refunds on black lung excise taxes paid by the industry on export

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

sales. The notice was the result of a 1998 federal district court decision that found such taxes to be unconstitutional.

During the year ended December 31, 2001, the Company received a state tax credit covering prior periods that resulted in a pre-tax gain of $7.4 million. As a result of several litigation settlements, the Company increased its litigation reserve during 2001, resulting in a pre-tax decrease in income of $5.6 million. The Company also increased its stock-based benefit program accruals for awards that met minimum performance levels to qualify for a payout. This resulted in a decrease in pre-tax income of $4.1 million during the year ended December 31, 2001. During 2001, Canyon Fuel, the Company s equity method investment, recognized recoveries of previously paid property taxes. The Company s share of these recoveries was $2.6 million and is reflected in income from equity investment on the Consolidated Statements of Operations for the year ending December 31, 2001. The Company recognized a $13.5 million pre-tax gain in 2001 primarily as a result of selling land.

3. Acquisition of Triton Coal Company, LLC

On May 29, 2003, the Company entered into a definitive agreement to acquire (1) Vulcan Coal Holdings, L.L.C. (Vulcan), which owns all of the common equity of Triton Coal Company, LLC (Triton), and (2) all of the preferred units of Triton, for an aggregate purchase price of $364.0 million, subject to working capital adjustments. Consummation of the transaction is subject to various conditions, including the receipt by the Company and Vulcan of all necessary governmental and regulatory consents and other customary conditions. Upon consummation, the acquisition will be accounted for under the purchase method of accounting in accordance with FASB Statement No. 141, *Business Combinations.* The Company intends to finance the acquisition with cash, borrowings under its existing revolving credit facility and a $100.0 million term loan facility at its Arch Western subsidiary.

As of December 31, 2003, the Company has capitalized legal and other costs associated with the acquisition totaling $3.6 million. In addition, the Company is obligated to pay $2.9 million of retention bonuses to Vulcan employees. In the event the transaction is not consummated, such costs will be expensed.

On January 30, 2004, the Company entered into an agreement to sell the Buckskin mine to Peter Kiewit and Sons Inc. for a purchase price of approximately $82.0 million. The completion of the sale of the Buckskin mine is contingent, among other things, on the completion of the Company s acquisition of Triton.

4. Other Comprehensive Income

Other comprehensive income items under Statement of Financial Accounting Standards No. 130, *Reporting Comprehensive Income,* are transactions recorded in stockholders equity during the year, excluding net income and transactions with stockholders. Following are the items included in other comprehensive income (loss), net of a 39% tax rate:

	Financial Derivatives	Minimum Pension Liability Adjustments	Accumulated Other Comprehensive Loss
Adoption (January 1, 2001)	$ (4,825)	$	$ (4,825)
2001 activity	(13,153)	(2,851)	(16,004)
Balance December 31, 2001.	(17,978)	(2,851)	(20,829)
2002 activity	(5,192)	(16,416)	(21,608)
Balance December 31, 2002.	(23,170)	(19,267)	(42,437)
2003 activity	**(989)**	**3,403**	**2,414**
Balance December 31, 2003.	$(24,159)	$(15,864)	$(40,023)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The 2003 activity for financial derivatives is comprised of unrealized mark-to-market losses (net of tax) of $5.8 million and reclassifications of $4.8 million (net of tax) to net income.

5. Equity Investments

The Company s equity investments are comprised of its ownership interests in Canyon Fuel and NRP. Amounts recorded in the Consolidated Financial Statements are as follows:

	December 31,	
	2003	2002
Equity investments:		
Investment in Canyon Fuel	$146,180	$160,787
Investment in NRP	25,865	70,764
Equity investments as reported in Consolidated Balance Sheets	$172,045	$231,551

	Year Ended December 31,		
	2003	2002	2001
Income from equity investments:			
Income from investment in Canyon Fuel	$19,707	$ 7,774	$26,250
Income from investment in NRP	14,683	2,318	
Income from equity investments in the Consolidated Statements of Operations	$34,390	$10,092	$26,250

Investment in Canyon Fuel

The following tables present unaudited, summarized financial information for Canyon Fuel, which is accounted for on the equity method.

Condensed Income Statement Information

	Year Ended December 31,		
	2003	2002	2001
Revenues	$242,060	$250,325	$301,909
Total costs and expenses	223,357	249,325	275,883
Net income before cumulative effect of accounting change	$ 18,703	$ 1,000	$ 26,026
65% of Canyon Fuel net income	$ 12,157	$ 650	$ 16,917
Effect of purchase adjustments	7,550	7,124	9,333

Arch Coal s income from its equity investment in Canyon Fuel	$ 19,707	$ 7,774	$ 26,250

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Condensed Balance Sheet Information

	December 31, 2003			
	Canyon Fuel Basis	Arch Ownership of Canyon Fuel Basis	Arch Purchase Adjustments	Arch Basis
Current assets	$ 51,660	$ 33,579	$ (2,492)	$ 31,087
Noncurrent assets	324,777	211,105	(59,622)	151,483
Current liabilities	25,692	16,700		16,700
Noncurrent liabilities	30,292	19,690		19,690
Members equity	$320,453	$208,294	$(62,114)	$146,180

	December 31, 2002			
	Canyon Fuel Basis	Arch Ownership of Canyon Fuel Basis	Arch Purchase Adjustments	Arch Basis
Current assets	$ 64,365	$ 41,837	$ (2,493)	$ 39,344
Noncurrent assets	346,530	225,245	(68,357)	156,888
Current liabilities	30,221	19,644		19,644
Noncurrent liabilities	25,135	16,338	(537)	15,801
Members equity	$355,539	$231,100	$(70,313)	$160,787

The Company s income from its equity investment in Canyon Fuel represents 65% of Canyon Fuel s net income after adjusting for the effect of purchase adjustments related to its investment in Canyon Fuel. The Company s investment in Canyon Fuel reflects purchase adjustments primarily related to the reduction in amounts assigned to sales contracts, mineral reserves and other property, plant and equipment. The purchase adjustments are amortized consistent with the underlying assets of the joint venture. During 2001, in accordance with Statement of Financial Accounting Standards No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of,* Canyon Fuel wrote off its investment in LAXT, a coal terminal located in Los Angeles, resulting in a charge of $10.1 million. The Company did not value LAXT in its Canyon Fuel purchase allocation and, therefore, the charge had no impact on the Company s financial position.

Effective January 1, 2003, Canyon Fuel adopted FAS 143 and recorded a cumulative effect loss of $2.4 million. The Company s 65% share of this amount was offset by purchase adjustments of $0.5 million. These amounts are included in the cumulative effect of accounting change reported in the Company s Consolidated Statements of Operations.

Investment in Natural Resource Partners, L.P.

During 2002, the Company contributed 454 million tons of coal reserves with a net book value of $84.9 million to Natural Resource Partners L.P. in exchange for 4.8 million of NRP s common limited partnership units, 4.8 million of NRP s subordinated limited partnership units, and 42.25% of NRP s general partner interest. Concurrent with the contribution, the Company entered into various leases with NRP for the right to mine approximately 57 million tons of the contributed reserves. No gain was recorded at the time of the contribution of the reserves and formation of NRP. The excess of the Company s percentage ownership of NRP s partners equity over the Company s historical basis in the assets contributed to NRP (approximately $12.4 million and $37.2 million at December 31, 2003 and 2002, respectively) is being recognized as income from equity investment over the expected life of the reserves contributed to NRP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On October 17, 2002,