Massey Energy

MEET THE ENERGY BEHIND MASSEY ENERGY

MASSEY ENERGY COMPANY 2007 ANNUAL REPORT

FINANCIAL HIGHLIGHTS

(In millions, except per share, per ton and number of employees amounts)	*Year Ended December 31,* 2007	2006	2005	2004	2003
Consolidated Statement of Income Data					
Produced coal revenue	$ 2,054.4	$ 1,902.3	$ 1,777.7	$ 1,456.7	$ 1,262.1
Total revenue	2,413.5	2,219.9	2,204.3	1,766.6	1,571.4
Income (Loss) before interest and income taxes	179.7	111.0	(20.9)	46.2	(17.5)
Income (Loss) before cumulative effect of accounting change	94.1	41.6	(101.6)	13.9	(32.3)
Net income (loss)	94.1	41.0	(101.6)	13.9	(40.2)
Income (Loss) per share – Basic					
Income (Loss) before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)	$ 0.18	$ (0.43)
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)	$ 0.18	$ (0.54)
Income (Loss) per share – Diluted					
Income (Loss) before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)	$ 0.18	$ (0.43)
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)	$ 0.18	$ (0.54)
Dividends declared per share	$ 0.17	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Consolidated Balance Sheet Data					
Working capital	$ 522.6	$ 445.2	$ 670.8	$ 458.4	$ 443.2
Total assets	2,860.7	2,740.7	2,986.5	2,650.9	2,376.7
Long-term debt	1,102.7	1,102.3	1,102.6	900.2	784.3
Shareholders' equity	784.0	697.3	841.0	776.9	759.0
Other Data					
EBIT	$ 179.7	$ 111.0	$ (20.9)	$ 46.2	$ (17.5)
EBITDA	$ 425.7	$ 341.5	$ 213.6	$ 270.8	$ 179.0
Average cash cost per ton sold	$ 43.10	$ 42.33	$ 35.62	$ 30.50	$ 28.23
Produced coal revenue per ton sold	$ 51.55	$ 48.71	$ 42.02	$ 36.02	$ 30.79
Capital expenditures	$ 270.5	$ 298.1	$ 346.6	$ 347.2	$ 164.4
Produced tons sold	39.9	39.1	42.3	40.4	41.0
Tons produced	39.5	38.6	43.1	42.0	41.0
Number of employees	5,407	5,517	5,709	5,034	4,428

All financial data should be read in conjunction with the audited Consolidated Financial Statements and Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K for the period ended December 31, 2007, filed with the Securities and Exchange Commission on February 29, 2008, provided herein.

Produced Coal Revenue
in billions

Cash Margin/Ton
in dollars

EBITDA
in millions

OUR MEMBERS

We'd like to take this opportunity to express our thanks to the men and women of Massey Energy. These Massey members are our most important resource and their daily contributions drive our Company's success.

DEAR FELLOW SHAREHOLDERS:

We are pleased to provide you with this report on a very successful 2007. By many measures, we had one of the best years in our long and proud history. We set a record for EBITDA, generating nearly $426 million. We increased our cash balance at year end by $126 million as compared to a year ago, even after returning $43 million to you in the form of dividends and repurchases of our common stock.

In addition to our financial success, we took a series of steps in 2007 that put us in a strong position to pursue even greater accomplishments in 2008. We expanded our overseas markets, increased our domestic coal reserves, improved our product mix and, most importantly, we launched an aggressive expansion plan that will propel us into the next decade. Our accomplishments in 2007 and our future opportunities make this a very exciting time for Massey, our members and our shareholders.

As nations around the world seek to balance economic growth, expanding energy demands and environmental responsibility, coal continues to be a vital international energy source. In the United States, coal provides both jobs and energy - without fear of disruptions, fluctuations or foreign policy entanglements. About half of the electricity that serves American homes and businesses comes from coal.

Overseas, the ever-expanding energy needs of developing countries have led to a dramatic increase in demand for coal. Massey Energy has taken advantage of rising coal prices by increasing our exports of metallurgical coal for steel production and thermal coal for electricity generation in various foreign markets. We've also taken steps to build a foundation for future international growth prospects.

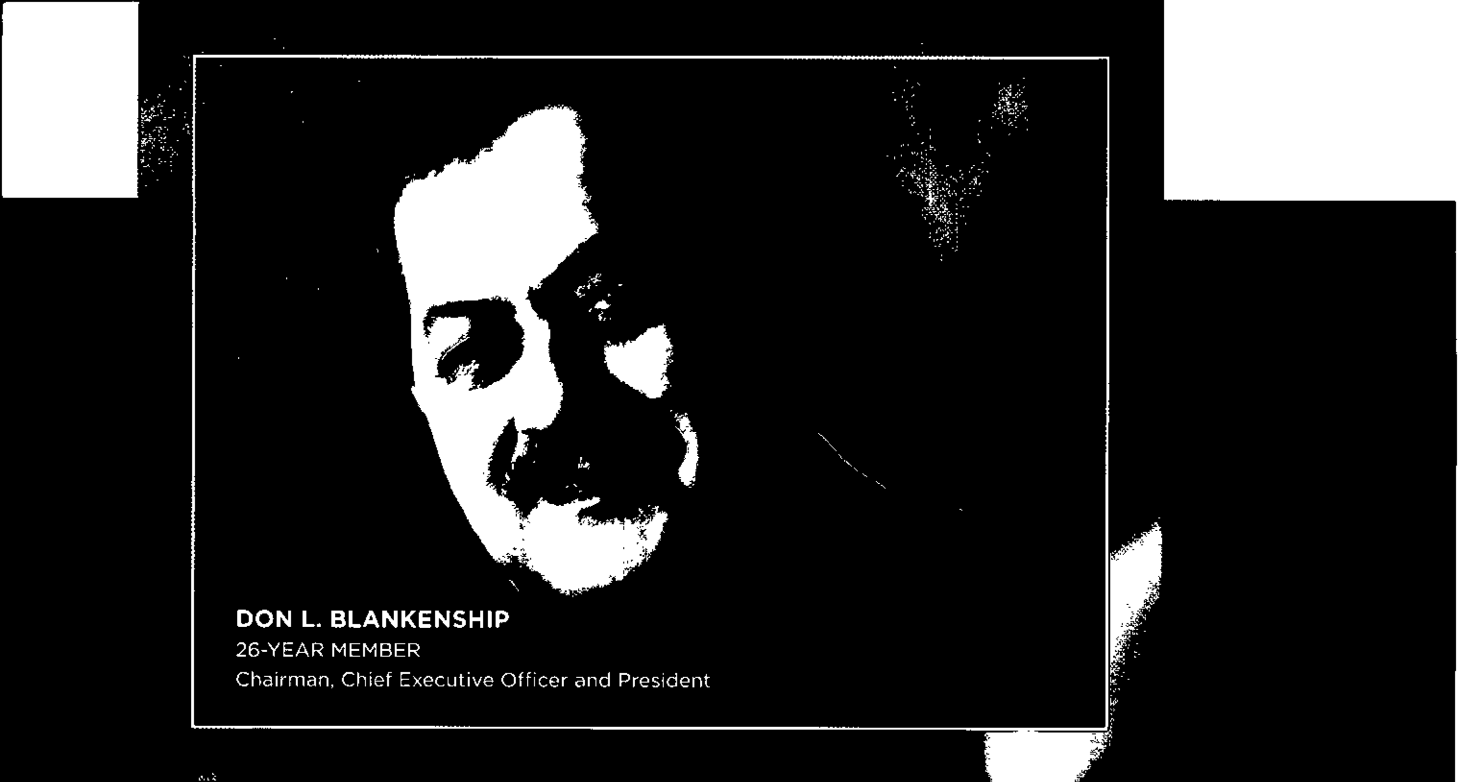
In India, for example, we entered into an agreement with Essar Mineral Resources Ltd., a member of the Essar Group of India, to jointly evaluate and develop business opportunities on a project-by-project basis. Essar's desire to dramatically increase its steel production and energy generation offers obvious opportunities for Massey Energy.

We are actively pursuing customer relationships and other opportunities in South America, Asia and Europe as well.

While expanding our reach in the global marketplace, we have maintained our focus on the fundamentals. Our Company has been mining coal in Central Appalachia for more than 50 years, and we believe we have the best and most productive workforce in the industry. We are committed to the safety and well-being of the more than 5,400 Massey members who are the backbone of our Company.

We continued to be an industry leader in safety during 2007. Our safety record in terms of work days lost was 37% better than the national industry average. Our Raymond Bradbury Safety Program and our S-1 campaign - "Safety is Job One" - make safety an integral part of our Company culture. Our mine rescue teams are recognized as among the best in the mining industry. Three of our mines were honored with West Virginia Mountaineer Guardian Awards for their exemplary safety efforts.

In 2007, we helped to ensure that Massey members have a secure future by increasing our coal reserves to about 2.3 billion tons, improving our balance sheet and increasing our forward sales commitments at price levels that will generate improved profitability and increased cash flow. This combination enabled us to announce and initiate an aggressive expansion plan that will increase our annual coal production by approximately 8 million tons over the next three years. We'll do it by expanding our operations at key mines, developing several new mines and improving efficiency. This expansion will allow us to take full advantage of the strong demand and higher prices in domestic and global coal markets.



DON L. BLANKENSHIP
26-YEAR MEMBER
Chairman, Chief Executive Officer and President

Investors have responded to our efforts to strengthen the Company and prepare for the future. At the start of the year, our stock traded at less than $22 a share. We ended the year at nearly $36 a share. We have the capital, the resources and the market conditions to leverage our reserve base and infrastructure to the benefit of shareholders, Massey members and the communities in which we operate.

As further evidence of our commitment to Central Appalachia, we broke ground in 2007 on a new regional headquarters in Boone County, West Virginia. The new facility is centrally located to oversee our operations in West Virginia, Kentucky and southwestern Virginia. Of course, our commitment to community goes well beyond a new building. We strive to be a good neighbor in all of the communities in which we operate. We partner with local schools, sponsor holiday events for children of low-income families, donate to local fire departments and other civic endeavors, and encourage community involvement by Massey members.

We also work to protect our environment through our extensive reclamation efforts and our cooperation with environmental groups. We recycle nearly all of the water used by our processing facilities and plant about a million trees annually on reclaimed land. Another example of our environmental protection efforts occurred during the fall of 2007 when Massey members joined other volunteers in efforts to improve and protect the Coal River Nature Preserve, near Tornado, West Virginia. Massey contributed member time, equipment and tons of rock to build an access road and rock barriers to protect the property. The Coal River group is also working with Massey Energy to help protect 200 acres of land that the Company agreed to preserve from development or mining.

In last year's report, I set forth four goals to pursue in 2007. I said we would improve our safety record, which I'm happy to report we accomplished. I pledged to strengthen our balance sheet and return value to shareholders. We certainly achieved that goal. And I said we would end the year in a stronger strategic position, and I believe we have done that. The fourth goal was to decrease cash costs. While costs increased slightly during the year, we were successful at limiting the increase to the point that still allowed us to realize solid improvement in our cash margin per ton.

The achievements in 2007 will be the foundation for our success in 2008 and beyond, and they are a tribute to the continued dedication of Massey members. Our members do the hard work required to move this Company forward and they will drive us to even greater success in 2008. As an expression of my appreciation, I would like to dedicate this year's annual report to the 5,400-plus Massey members – the men and women who are the true energy behind Massey Energy.

Don L Blankenship

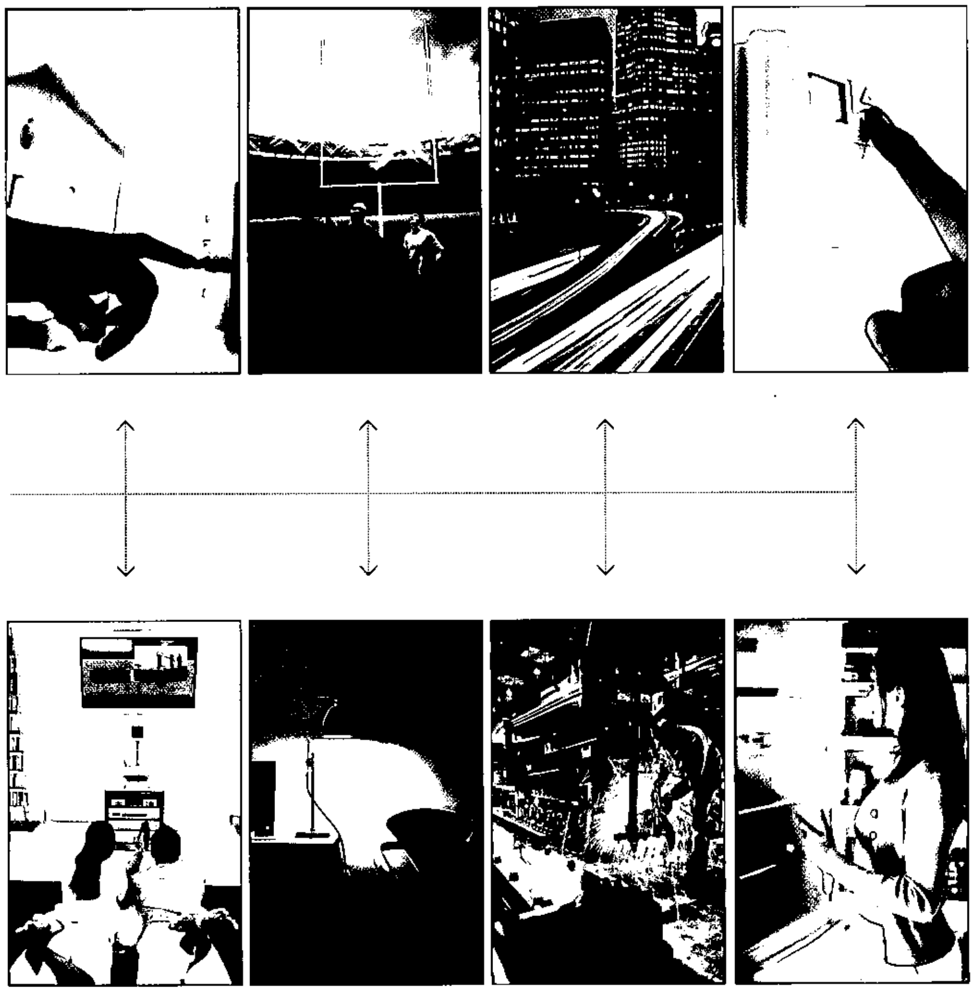
Don L. Blankenship
Chairman, Chief Executive Officer and President

IMPORTANCE OF COAL IN SOCIETY

Global demand for energy has increased nearly 70% since 1980 and is projected to increase by as much as an additional 40% in the next 20 years. Where will the additional energy come from? One very important answer is coal.

Coal is by far our most plentiful domestic source of energy, and increasing the responsible use of coal will help keep energy prices affordable, improve our energy independence and ultimately help to ensure our national security and domestic stability.

Recent government estimates indicate that coal accounts for 26% of the total global energy consumption; it is projected to increase to 28% by 2030. Coal is used to generate 43% of the world's electricity and this is projected to increase to 45% by 2030.



In the United States, 50% of all electricity is generated from coal. The Department of Energy expects this to increase to 55% by the year 2030 because the expected growth of alternative fuel sources will not be sufficient to meet increasing energy needs for at least two decades.

KEY STATISTICAL INFORMATION ABOUT COAL

50% OF THE ELECTRICITY IN THE UNITED STATES IS GENERATED FROM COAL

ON AVERAGE, EACH PERSON IN THE UNITED STATES USES **3.8 TONS** OF COAL EACH YEAR

234 YEARS' WORTH OF PROVEN U.S. COAL RESERVES VS. 11 YEARS FOR NATURAL GAS AND 12 YEARS FOR OIL

OUR FORMULA FOR SUCCESS:
S-1 + P-2 + M-3 = SHAREHOLDER VALUE

At Massey, we have built the most successful and enduring coal mining company in Central Appalachia by adhering to three key operating standards: S-1, P-2 and M-3:

S-1 SAFETY + **P-2 PRODUCTIVITY** + **M-3 MEASUREMENT** = **SHAREHOLDER VALUE**

SAFETY IS JOB ONE.
As our members safely arrive on the job each morning, our first priority is to ensure that they go safely home each night. Our continuous safety innovations are evidence of our commitment to operating safe coal mines.

PRODUCTION STANDARDS LEAD THE INDUSTRY.
Massey promotes the application and implementation of best production practices. Extensive training and communication programs ensure that technological advancements are implemented in each of our resource groups.

MEASUREMENT DATA TO INFORM COMPANY DECISIONS.
Massey's M-3 standard requires that managers receive timely, accurate measurement data related to the Company's daily operations, enabling them to make the best decisions based on the best information.

This proven formula has enabled us to endure and grow in both strong and weak energy markets over many years while other Central Appalachian coal companies have been less successful or have failed. It is a hallmark of our Company and will continue to be our formula for generating long-term shareholder value.

MEMBERS
At Massey, the only things more important than our natural resources are our human resources.

SAFETY
"Safety First" is not just a slogan at Massey. It is an integral part of our daily routine.

COMMUNITY
Demonstrating appreciation for our roots and a commitment to the children who are our future.

ENVIRONMENT
Commitment to the responsible use, protection and preservation of the land, air and water in Central Appalachia.

OUR CORE FOUR: The application of our formula for success and our overall operating strategy is dependent upon four core areas of focus: our members, the safety of our operations, the communities in which we live and work, and responsible environmental care and accountability. Massey remains committed to doing the right things over the long term that will ensure the sustainability of our Company. The following pages highlight our efforts and successes in each of these areas during 2007.

BRUCE JACKSON
1-YEAR MEMBER

"There is a difference at Massey. I feel like I am working for more than my own success. There is a certain satisfaction in helping the other members and the Company as a whole to continue a tradition of success."

GREG KESSLER
NEW MEMBER

"Stability is very important to me in my career. Massey has been the most stable of all the coal companies in Central Appalachia for the better part of the last century. As a new member, I like the fact that we have vast reserves and the capital to continue mining well into the new century."

EDDIE LESTER
24-YEAR MEMBER

"Over my time with Massey, I have seen a lot of miners come and go. A lot of the guys who leave come back after just a short time. I don't think there's a better coal company to work for. Massey has been good to me."

OUR MOST IMPORTANT RESOURCE

More than our vast coal reserves, more than our expansive mining infrastructure, our members are our most important resource.

They are not just employees putting in time in exchange for a pay check. Rather, they are part of a team that is committed to pursuing and achieving excellence in the workplace every day. In the course of doing their jobs, many of our members go above and beyond their normal duties to accomplish extraordinary results, benefiting the Company, other members and our shareholders. Working together, our members truly are the energy that drives Massey Energy.

With more than 5,400 members in Kentucky, Virginia and West Virginia, Massey Energy is one of Central Appalachia's largest private sector companies. More than 4,000 of our members work in West Virginia. Our members live in the areas where we operate. They are active in their communities and area schools.

We are pleased to offer our members one of the most competitive compensation and benefits packages within the industry. Our medical insurance plan – including vision and dental benefits – ranks in the top 10% of health insurance packages in the nation. We also provide post-retirement pension and healthcare plans that will protect our members well into the future.

To keep our members healthy, we built the West Virginia Wellness Center in Madison, West Virginia to provide them with the highest quality healthcare available in southern West Virginia.

To encourage continued personal growth and development, Massey offers a tuition reimbursement program for eligible continuing education expenses. Many of our brightest leaders have been hired coming out of local schools and universities, often after serving internships with Massey while still in school. We strive to develop the best young talent in the area and provide them with opportunities to advance rapidly by promoting from within.

Finally, we provide both a defined benefit pension plan and a 401-K defined contribution retirement savings plan. Massey matches a portion of member contributions to the savings plan. Just as important, we are pleased that our pension program is fully funded – offering a secure future to our members and their families.

As we focus on growing in Central Appalachia, we know that our members will be the driving force behind our success. With a mix of seasoned coal mining veterans and new, eager coal miners, our future has never looked brighter.

Left to right:

Gordon Fields, 12-year member

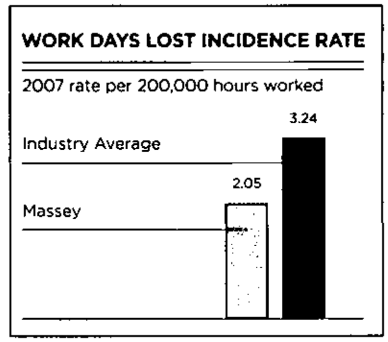
Bennett Justice, 12-year member, and Vernon Blackburn, 13-year member, attend a mine planning meeting at Sidney Coal resource group

Shirl Ratliffe, 17-year member, monitors operations at the Sidney Coal processing plant

SAFETY FIRST

"S-1" means Safety First at Massey Energy, and it's not just a slogan. It's an integral part of our daily routine. Our S-1 safety program is recognized as one of the best in the industry, setting standards that far exceed federal and state requirements.

The program, designed for sustained safety improvement, uses a well-developed process of training, mentoring, monitoring and reduction of risk through innovation and recognition of safety excellence. The result is a culture of safety.



RECORD-SETTING YEAR

In 2007, our non-fatal days lost (NFDL) accident incident rate was 37% better than the bituminous coal industry incident rate. Massey achieved a 2.05 NFDL incident rate per 200,000 hours worked compared to a 3.24 NFDL incident rate estimated for the bituminous coal industry overall. Our safety performance in 2007 improved 26% over our performance in 2006 making 2007 the safest year in Massey Energy history.

RECOGNIZING EXCELLENCE

Three of our mines were recognized for their excellence in safety with West Virginia Mountaineer Guardian Awards and six mines received Holmes Safety Awards in 2007. The association named Charles Roach, a foreman at our Castle Mine, Co-Safety Leader of the Year for 2006.

Internally, Massey Energy encourages and recognizes exemplary safety efforts of teams and individuals with our nationally acclaimed Raymond Safety Awards Program. The company-wide program and its highest award, the Bradbury Award, were named in honor of retired executive Raymond Bradbury who was known for his slogan, "a safe mine is a productive mine." This program will mark its 16th anniversary in 2008, and the Bradbury award is as coveted as ever.

INNOVATIONS DRIVE IMPROVEMENT

Massey has long been an innovator of safety enhancements and has introduced many safety practices that have subsequently been adopted throughout the mining industry in the United States and around the world. Since the establishment of our S-1 safety program, the innovation has increased. Following is a chronology of just a few of these Massey innovations:

1993	Massey mandates the use of reflective clothing
	Massey mandates use of metatarsal work boots for mining operations
1994	Massey implements seat belt policy for all mining equipment
1995	Massey designs, develops and implements ATRS flapper pads for roof bolters
	Massey replaces ladders on large trucks with steps to reduce falls
1996	Massey requires the use of strobe lights on underground vehicles
1999	Massey installs lights on all belt line feeders
	Massey adds submarine safety package on stockpile dozers and loaders
2000	Massey requires the use of reflective tape on all surface vehicles
2002	Massey adds submarine safety package on highwall excavators and shovels
	Massey implements continuous miner radio remote safety precautions
2003	Massey installs safety cameras on surface haulage trucks
	Massey begins developing continuous miner proximity protection device
2007	Massey develops self-contained foam fire-fighting car

Left to right:

Massey's Southern WV mine rescue team placed fourth in a national competition

Mine rescue team member Shane McPherson dons rescue gear

Massey's 300 miles of belt lines reduce the need for heavy trucks and improve safety on public highways

ELIZABETH CHAMBERLIN
Vice President, Safety and Training
1-YEAR MEMBER

"We strive for sustainable excellence in safety. It is our top priority every day. We are proud of our tradition of developing safety innovations, which we freely share with others to the benefit of the entire industry."

When Elizabeth Chamberlin joined Massey, she took over an already very successful safety program. However, in just over a year, she has asserted her experience, leadership and enthusiasm to re-emphasize the "culture of safety" throughout the Company. That culture is epitomized within the Raymond Bradbury Safety Program. This program engages all Massey members in our safety initiatives through competition and by providing team and individual rewards for safety excellence. The results are clear. In the 15 years since the Bradbury Program was introduced, Massey has reduced its non-fatal days lost (NFDL) incident rate by 64%.

Below: Elizabeth Chamberlin, Vice President, Safety and Training; Robert Asbury, Safety Director, 11-year member (left); Michael Vaught, Safety Director, 8-year member (right).

KEY FACTS ON COAL INDUSTRY SAFETY

FATAL OCCUPATIONAL INJURIES BY INDUSTRY	
Construction	32%
Transportation	22%
Agriculture	17%
Manufacturing	12%
Retail Trade	9%
Coal Mining	1%

2007 BRADBURY AWARD RECIPIENT

On March 11, 2008, over 500 Massey members, government officials, dignitaries and guests gathered in Charleston, WV to honor Aracoma Coal Company, the recipient of the Bradbury Award for 2007. Aracoma operated 2 mines in 2007 without a single lost-time accident.

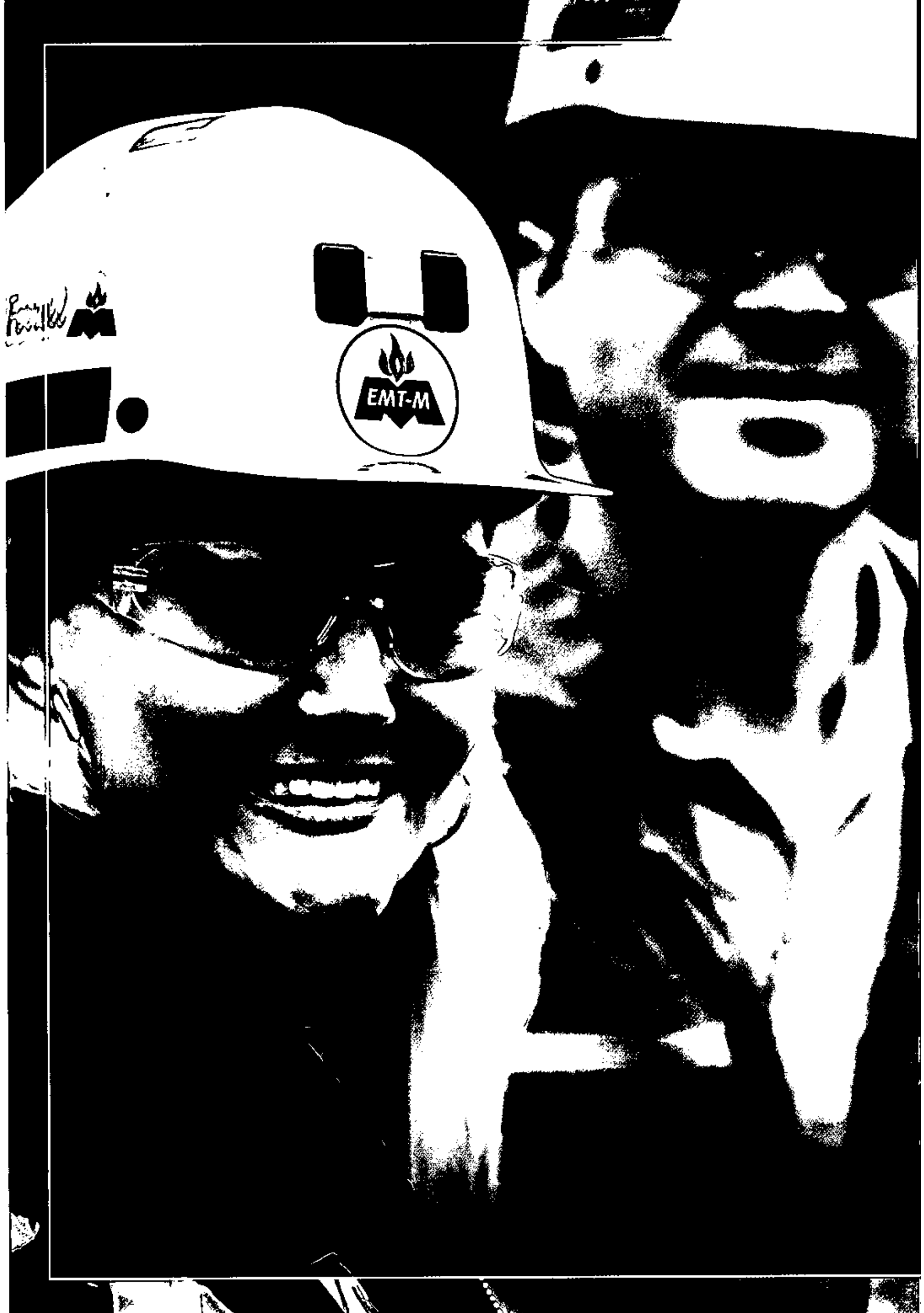
NATALIE FERRELL
Environmental Engineer
2-YEAR MEMBER

"It is important to me to work for a company that produces coal in an environmentally friendly way in the coal fields where I grew up and now raise my kids."

THOMAS COOK
Director, Environmental Affairs
4-YEAR MEMBER

"The members at Massey have acted on the opportunity to be among the leading environmental stewards in the industry. Through team effort and increased focus, we significantly improved our environmental performance in 2007. We achieved 160% of our goal to reduce state issued violations, and continue to maintain high objectives for the future."

Thomas and Natalie are just two out of a team of many Massey environmental engineers, technicians and specialists who focus full-time on our environmental efforts. Whether working on obtaining mine permits, monitoring regulatory compliance or conducting reclamation projects, these dedicated professionals are setting new standards for environmental leadership and innovation.



2007 KEY ENVIRONMENTAL STATISTICS

- Incidents of environmental non-compliance reduced by 36%
- Surface mine citations reduced by 43%
- 200 acres of land designated as conservation easement

MASSEY PLANTED
OVER 1 MILLION TREES
IN 2007 AS PART OF RECLAMATION PROJECTS

MASSEY ENVIRONMENTAL AWARDS

- The Surface Mine Award - Anna Branch Surface Mine
- The Haul Road South Award - Aracoma Coal Company
- The Woodlands Award - Elk Run Coal Company, Black Castle Mine

ENVIRONMENT

Most of the men and women working at Massey Energy were born and raised in Appalachia – the region's mountains, trees, rivers and wildlife are a part of their lives and a legacy for their families.

So it stands to reason that Massey and all its members are committed to the protection and preservation of the land, air and water in Central Appalachia. As Appalachia's largest and leading mining company, Massey Energy has the resources and expertise to support multi-faceted environmental activities at all mines and facilities. The personnel, equipment, new technologies and training are part of the Company's drive to continually improve its environmental protection efforts.

In 2007, across all Massey Energy Resource Groups, there was a concerted effort among members to improve the Company's environmental performance. The result was a 36% reduction in overall violations from state regulatory agencies. Our Logan County Resource Group led the way, achieving an outstanding 70% reduction. The success was attributable to the miners, engineers, technicians and environmental managers who make environmental compliance a priority – every day.

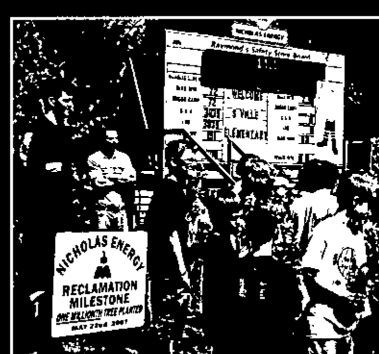
WATER – AN ESSENTIAL RESOURCE
Water is essential for mining operations; and it's essential for people and wildlife across Appalachia. That's why Massey Energy has committed millions of dollars in recent years to develop new mining industry technologies that prevent spills, protect watersheds and increase efforts to sustain Appalachia's environment.

Massey Energy maintains, monitors and tests more than 2,500 water outlets across its operations. The company is implementing an entirely new computerized system to report, in near real time, the water quality of its outlets to make certain it is meeting or exceeding all state and federal Clean Water Act mandates.

This $100,000 investment will enable Massey's water quality engineers to monitor each outlet and identify potential excessive particulates in water in a matter of days, rather than a matter of weeks. Plus, by moving from a paper to a computerized system, Massey is at the forefront of the industry.

RECLAMATION ACTIVITIES
Massey Energy's strong history of environmental stewardship is clearly seen through its reclamation efforts, which over the years have included the planting of millions of trees and the successful reclamation of thousands of acres. Massey has reclaimed more acres of land in West Virginia and Central Appalachia than any other mining company.

In reforestation projects, Massey plants a combination of hardwood and faster-growing softwood trees and has achieved an outstanding tree survival rate. One of our most exciting projects is aiding in the effort to return the American chestnut tree to Appalachia. Once the greatest tree in the Appalachian landscape, it was nearly wiped out by a fungus in the early 1900s. Now, working with botanists and forestry experts at West Virginia University and the American Chestnut Foundation, Massey is helping to bring it back to the area as part of our reclamation efforts. The tree grows well in soil conditions commonly found on reclaimed land.



Left to right:

Logan County Mine Services members receive a reclamation award

17-year member Keith Runyon, 6-year member Joey Elia and 2-year member John Long review reclamation plans

Children from a local elementary school join Massey members in celebrating the planting of 1 million trees in 2007

COMMUNITY

Our roots run deep in Central Appalachia and our members make up a key part of the area's close-knit communities.

More than where we work – the communities of West Virginia, Kentucky and Virginia are where we live and raise our families. Massey makes significant contributions to the communities in which we operate, and encourages community involvement by our members. This is an important way for us to demonstrate our appreciation for our roots and our commitment to the communities and children that will drive our future.

DOCTORS FOR OUR COMMUNITIES

In cooperation with Marshall University, Massey provides financial assistance to medical students at the university's School of Medicine. By providing loans for M.D. candidates, the goal is to bring more qualified doctors to areas in which we operate. As further incentive, if a graduating physician maintains a practice of primary care medicine for a period of at least seven years in the area, the loan is forgiven.

PARTNERS IN EDUCATION

Through our Partners in Education program, we provide volunteers and generous financial assistance to elementary, middle and high schools throughout our operating region. Our contributions are used by partner schools to purchase educational materials and support field trips. Massey members also volunteer in our partner schools by reading to schoolchildren and assisting with school events.

CHRISTMAS EXTRAVAGANZA

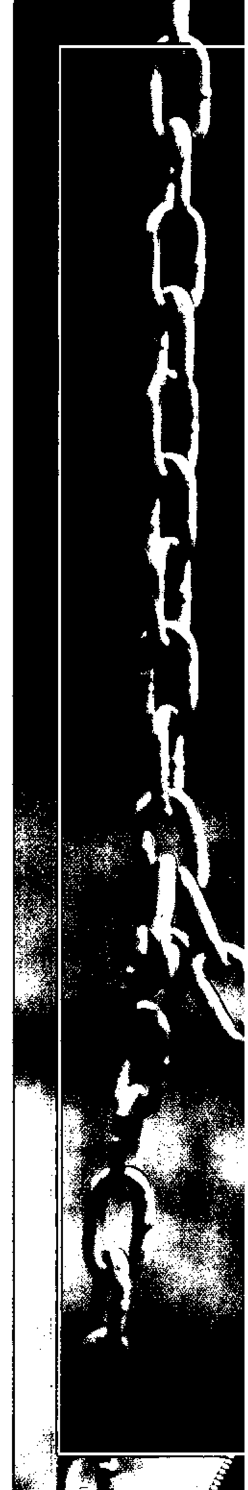
Entering its sixth year, the Massey Energy Christmas Extravaganza is an annual event that provides gifts to thousands of underprivileged children in our operating region. In 2007, Massey held six Christmas Extravaganza parties throughout southern West Virginia and eastern Kentucky benefiting nearly 3,000 children.

SPOUSAL GROUP

Created more than 20 years ago by Chairman Don Blankenship, the Massey Energy Spousal Group program serves as the catalyst for much of the Company's charitable work. Working in four regional groups, the spouses of Massey members join together to focus on resolving local community issues and providing much-needed charitable service. The group members volunteer their time and effort to identify and carry out each initiative. Massey provides financial support.

UNIVERSITY OF KENTUCKY DONATION

Massey Energy's gift of more than $300,000 will provide tuition assistance for mining engineering students, enhance the Department of Mining Engineering's laboratory facilities and support a student organization at the University of Kentucky over the next five years.



Left to right:

Andy Ashurst, a 17-year Massey member, visits the Massey Wellness Center for a regular check-up

3-year member Angela Smith enjoys passing out gifts at the Christmas Extravaganza

13-year member Jeff Gillenwater, Massey Director of External Affairs and Administration, pays a visit to a soccer field that Massey helped to construct in Belfry, Kentucky

CLAIRE VAUGHT
10-YEAR MEMBER

"My work in the engineering department of Massey's Independence Coal resource group has been personally rewarding. My role as a coordinator for the Massey Energy Spousal Group gives me a chance to work with great volunteers and give something back to the community."

SUSAN BERRY
8-YEAR SPOUSAL GROUP VOLUNTEER

"I love being a part of the Massey Spousal Group. With financial support from Massey, members of this community are working together to make a true difference in our parks, in our schools and in our neighborhoods."

MARY ANN OSBORNE
2-YEAR SPOUSAL GROUP VOLUNTEER

"The Spousal Group identified the need to improve a local park. Massey provided the playground equipment and our group volunteers worked together to plant flowers, shrubs and keep the park clean."

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
(In thousands, except per share amounts)	2007	2006	2005
Revenues			
Produced coal revenue	$ 2,054,413	$ 1,902,259	$ 1,777,724
Freight and handling revenue	167,641	156,531	150,898
Purchased coal revenue	108,191	70,636	132,320
Other revenue	83,278	90,428	143,316
Total revenues	2,413,523	2,219,854	2,204,258
Costs and Expenses			
Cost of produced coal revenue	1,641,774	1,599,092	1,438,494
Freight and handling costs	167,641	156,531	150,898
Cost of purchased coal revenue	95,241	62,613	112,600
Depreciation, depletion and amortization, applicable to:			
Cost of produced coal revenue	242,755	227,279	230,545
Selling, general and administrative	3,280	3,259	4,020
Selling, general and administrative	75,845	53,834	68,254
Other expense	7,308	6,240	8,018
Loss on capital restructuring	–	–	212,378
Total costs and expenses	2,233,844	2,108,848	2,225,207
Income (Loss) before interest and taxes	179,679	111,006	(20,949)
Interest income	23,969	20,094	12,603
Interest expense	(74,145)	(86,076)	(67,064)
Income (Loss) before taxes	129,503	45,024	(75,410)
Income tax expense	(35,405)	(3,408)	(26,228)
Income (Loss) before cumulative effect of accounting change	94,098	41,616	(101,638)
Cumulative effect of accounting change, net of tax	–	(639)	–
Net income (loss)	$ 94,098	$ 40,977	$ (101,638)
Income (Loss) per share – Basic			
Income (Loss) before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)
Cumulative effect of accounting change	–	(0.01)	–
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)
Income (Loss) per share – Diluted			
Income (Loss) before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)
Cumulative effect of accounting change	–	(0.01)	–
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)
Shares used to calculate income per share			
Basic	80,123	80,847	76,390
Diluted	80,654	81,386	76,390

All financial data should be read in conjunction with the audited Consolidated Financial Statements and Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K for the period ended December 31, 2007, filed with the Securities and Exchange Commission on February 29, 2008 provided herein.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share amounts)	Year Ended December 31, 2007	2006
Assets		
Current Assets		
Cash and cash equivalents	$ 365,220	$ 239,245
Trade and other accounts receivable, less allowance of $444 and $576, respectively	156,572	197,105
Inventories	183,360	191,056
Income taxes receivable	16,302	–
Other current assets	165,940	172,322
Total current assets	887,394	799,728
Net Property, Plant and Equipment	1,793,920	1,776,781
Other Noncurrent Assets		
Pension assets	47,323	34,974
Other noncurrent assets	132,034	129,213
Total other noncurrent assets	179,357	164,187
Total assets	$ 2,860,671	$ 2,740,696
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable, principally trade and bank overdrafts	$ 148,206	$ 117,157
Short-term debt	1,875	2,583
Payroll and employee benefits	46,512	40,380
Income taxes payable	–	19,412
Other current liabilities	171,269	175,005
Total current liabilities	367,862	354,537
Noncurrent Liabilities		
Long-term debt	1,102,672	1,102,324
Deferred income taxes	154,705	116,690
Other noncurrent liabilities	451,428	469,854
Total noncurrent liabilities	1,708,805	1,688,868
Total liabilities	2,076,667	2,043,405
Shareholders' Equity		
Capital Stock		
Preferred – authorized 20,000,000 shares without par value; none issued	–	–
Common – authorized 150,000,000 shares of $0.625 par value; issued 82,818,578 and 82,365,259 shares, respectively	51,743	51,458
Treasury stock, 2,874,800 and 1,299,000 shares at cost, respectively	(79,986)	(49,995)
Additional capital	237,684	220,650
Retained earnings	601,587	515,894
Accumulated other comprehensive loss	(27,024)	(40,716)
Total shareholders' equity	784,004	697,291
Total liabilities and shareholders' equity	$ 2,860,671	$ 2,740,696

All financial data should be read in conjunction with the audited Consolidated Financial Statements and Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K for the period ended December 31, 2007, filed with the Securities and Exchange Commission on February 29, 2008 provided herein.

DIRECTORS

Don L. Blankenship, 58
Mr. Blankenship has been Chairman of the Board, Chief Executive Officer and President of Massey Energy Company since November 30, 2000, and has been Chairman of the Board, Chief Executive Officer and President of A.T. Massey Coal Company, Inc., Massey Energy Company's wholly owned subsidiary, since 1992. He joined Rawl Sales and Processing Co., a Massey subsidiary, in 1982. Mr. Blankenship also serves as a director of the National Mining Association and the U.S. Chamber of Commerce. (1)

James B. Crawford, 65
Mr. Crawford has been a consultant for Evan Energy Investments, LC, a company with coal interests in China and Venezuela, since February 2004 and Chairman of InterAmerican Coal Holding S.A. since December 2005. He previously served as Chairman and Chief Executive Officer of James River Coal Company. He also is Chair Emeritus and a member of the Board of Trustees of Colby College and currently Chairman of the Board of Directors of the Boys and Girls Club of Metro Richmond Foundation. (1) (2) (3) (4) (5)

Robert H. Foglesong, 62
General Foglesong, U.S. Air Force (retired), has been President of Mississippi State University and President and Executive Director of the Appalachian Leadership and Education Foundation since 2006. He retired from the U.S. Air Force following 33 years of U.S. military service in over 130 countries. He is a director of Michael Baker Corporation and a member of numerous professional organizations, including the Council on Foreign Relations. (2) (3) (4) (5)

Richard M. Gabrys, 66
Mr. Gabrys retired as Vice Chairman of Deloitte & Touche LLP in May 2004 after 42 years of working with that company. He completed his service as Interim Dean of the School of Business Administration of Wayne State University in August 2007. Mr. Gabrys is a director of the following publicly traded companies: CMS Energy Company, La-Z-Boy Incorporated, and TriMas Corporation. He also serves on the boards of the Detroit Institute of Arts, the Karmanos Cancer Institute, Ave Maria College and Ave Maria University. (1) (4) (5) (6)

E. Gordon Gee, 64
Mr. Gee returned to The Ohio State University as its President in 2007, a position he had held from 1990 to 1998. He was President of Brown University from 1998 to 2000 and the Chancellor of Vanderbilt University from 2000 to 2007. Mr. Gee also serves as a director of the following publicly traded companies: Gaylord Entertainment Company, Hasbro, Inc. and Limited Brands, Inc. He previously served on numerous other publicly traded and private company boards. (1) (2) (4) (5)

Bobby R. Inman, 76
Admiral Inman, U.S. Navy (retired), has been a tenured professor at the LBJ School of Public Affairs at the University of Texas since 2001. He served as Interim Dean from during 2005. Admiral Inman previously served as Director of the National Security Agency and Deputy Director of the Central Intelligence Agency. He is a managing director of Gefinor Ventures, Inc., a venture capital firm, and has over 20 years experience in venture capital investments. (1) (3) (4)

Lady Judge, 61
Lady Judge became the chair of the Board of the United Kingdom Atomic Energy Authority in May 2004. An attorney, her career in international banking and financial regulation includes being a Commissioner of the SEC. She is currently a director of several foreign publicly traded companies. (4) (5) (6)

Dan R. Moore, 67
Mr. Moore is the Chairman of Moore Group, Inc. He previously served as Chairman, President and Chief Executive Officer of the former Matewan BancShares, a multi-bank holding company, from 1981 to 1999. Mr. Moore also serves as a director of the West Virginia University Foundation and previously served on other boards and foundations. (1) (2) (3) (4) (5) (6)

Baxter F. Phillips, Jr., 61
Mr. Phillips has been Executive Vice President and Chief Administrative Officer of Massey Energy Company since November 2004. Mr. Phillips joined Massey in 1981 and has held various positions, most recently Senior Vice President and Chief Financial Officer. Prior to joining Massey, he held various investment and banking positions. (5) (6)

(1) Executive Committee, Don L. Blankenship, Chairman; (2) Audit Committee, Dan R. Moore, Chairman; (3) Compensation Committee, Bobby R. Inman, Chairman; (4) Governance and Nominating Committee, James B. Crawford, Chairman; (5) Safety, Environmental and Public Policy Committee, E. Gordon Gee, Chairman; (6) Finance Committee, Richard M. Gabrys, Chairman.

OFFICERS

Don L. Blankenship
Chairman, Chief Executive Officer and President (1982)

Baxter F. Phillips, Jr.
Executive Vice President and Chief Administrative Officer (1981)

J. Christopher Adkins
Senior Vice President and Chief Operating Officer (1985)

Mark A. Clemens
Senior Vice President - Group Operations (1989)

Michael K. Snelling
Vice President - Surface Operations, Massey Coal Services, Inc. (2000)

Michael D. Bauersachs
Vice President - Planning (1998)

Richard R. Grinnan
Vice President and Corporate Secretary (2004)

M. Shane Harvey
Vice President and General Counsel (2000)

Jeffrey M. Jarosinski
Vice President - Finance and Chief Compliance Officer (1988)

John M. Poma
Vice President - Human Resources (1996)

Eric B. Tolbert
Vice President and Chief Financial Officer (1992)

David W. Owings
Corporate Controller (2001)

Numbers in parentheses indicate the year each officer joined the Company.

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2007

OR

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

For the transition period from to

Commission File No. 1-7775

MASSEY ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware	**95-0740960**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
4 North 4th Street, Richmond, Virginia	**23219**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (804) 788-1800

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.625 par value	New York Stock Exchange

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

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

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

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 ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," "non-accelerated filer" and "smaller reporting company in Rule 12b-2 of the Exchange Act (Check One):
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company)
Smaller reporting company ☐

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

The aggregate market value of the Common Stock held by non-affiliates of the registrant on June 30, 2007, was $2,162,792,929 based on the last sales price reported that date on the New York Stock Exchange of $26.65 per share. In determining this figure, the Registrant has assumed that all of its directors and executive officers are affiliates. Such assumptions should not be deemed to be conclusive for any other purpose.

Common Stock, $0.625 par value, outstanding as of February 15, 2008 — 80,491,644 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Part III incorporates certain information by reference from the registrant's definitive proxy statement for the 2008 Annual Meeting of Shareholders, which proxy statement will be filed no later than 120 days after the close of the registrant's fiscal year ended December 31, 2007.

Forward Looking Statements

From time to time, Massey Energy Company, which includes its direct and wholly owned subsidiary, A.T. Massey Coal Company, Inc, and its direct and indirect wholly owned subsidiaries ("we," "our," "us"), makes certain comments and disclosures in reports, including this report, or through statements made by our officers that may be forward-looking in nature. Examples include statements related to our future outlook, anticipated capital expenditures, projected cash flows and borrowings, and sources of funding. We caution readers that forward-looking statements, including disclosures that use words such as "believe," "anticipate," "expect," "estimate," "intend," "may," "plan," "project," "will" and similar statements are subject to certain risks, trends and uncertainties that could cause actual cash flows, results of operations, financial condition, cost reductions, acquisitions, dispositions, financing transactions, operations, expansion, consolidation and other events to differ materially from the expectations expressed or implied in such forward-looking statements. Any forward-looking statements are also subject to a number of assumptions regarding, among other things, future economic, competitive and market conditions. These assumptions are based on facts and conditions, as they exist at the time such statements are made as well as predictions as to future facts and conditions, the accurate prediction of which may be difficult and involve the assessment of circumstances and events beyond our control. We disclaim any obligation to update these forward-looking statements unless required by securities law, and we caution the reader not to rely on them unduly.

We have based any forward-looking statements we have made on our current expectations and assumptions about future events and circumstances that are subject to risks, uncertainties and contingencies that could cause results to differ materially from those discussed in the forward-looking statements, including, but not limited to:

(i) our cash flows, results of operation or financial condition;
(ii) the consummation of acquisition, disposition or financing transactions and the effect thereof on our business;
(iii) governmental policies and regulatory actions affecting the coal industry;
(iv) legal and administrative proceedings, settlements, investigations and claims and the availability of insurance coverage related thereto;
(v) weather conditions or catastrophic weather-related damage;
(vi) our ability to produce coal to meet market expectations and customer requirements;
(vii) our ability to obtain coal from brokerage sources or contract miners in accordance with their contracts;
(viii) our ability to obtain and renew permits necessary for our existing and planned operations in a timely manner;
(ix) the availability of transportation for our produced coal;
(x) the expansion of our mining capacity;
(xi) our ability to manage production costs, including labor costs;
(xii) adjustments made in price, volume or terms to existing coal supply agreements
(xiii) the market demand for coal, electricity and steel;
(xiv) concerns about the environmental impact of coal combustion and the cost and perceived benefits of alternative sources of energy such as natural gas and nuclear energy;
(xv) competition among coal and other energy producers, at home and abroad;
(xvi) our ability to timely obtain necessary supplies and equipment;
(xvii) our reliance upon and relationships with our customers and suppliers;
(xviii) the creditworthiness of our customers and suppliers;
(xix) our ability to attract, train and retain a skilled workforce to meet replacement or expansion needs;
(xx) our assumptions and projections concerning economically recoverable coal reserve estimates;
(xxi) future economic or capital market conditions and foreign currency fluctuations;
(xxii) the availability and costs of credit, surety bonds and letters of credit that we require;
(xxiii) the lack of insurance against all potential operating risks;
(xxix) our assumptions and projections regarding pension and other post-retirement benefit liabilities;
(xxx) our interpretation and application of accounting literature to mining specific issues; and
(xxxi) the successful implementation of our strategic plans and objectives, including our announced expansion plans.

Any forward-looking statements should be considered in context with the various disclosures made by us about our businesses, including without limitation the risk factors more specifically described below in Item 1A. Risk Factors of this Annual Report on Form 10-K. We are including this cautionary statement in this document to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf, of us.

2007 ANNUAL REPORT ON FORM 10-K

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Annual Shareholders Meeting

Our 2008 Annual Meeting of Shareholders will be held at 9:00 a.m. EDT on Tuesday, May 13, 2008 at The Jefferson Hotel, 101 West Franklin Street, Richmond, Virginia 23220.

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Part I

Because certain terms used in the coal industry may be unfamiliar to many investors, we have provided a Glossary of Selected Terms beginning on page 19 at the end of Item 1. Business.

Item 1. Business

Business Overview

We are one of the premier coal producers in the United States. As measured by 2007 revenue, Energy Ventures Analysis, Inc. ("EVA") ranks us as the fourth largest United States coal company in terms of coal revenue. We are the largest coal company in Central Appalachia, our primary region of operation, in terms of revenue, tons produced and total coal reserves.

We produce, process and sell bituminous coal of various steam and metallurgical grades, primarily of a low sulfur content, through our 22 processing and shipping centers ("Resource Groups"), many of which receive coal from multiple mines. At January 31, 2008, we operated 47 mines, including 35 underground (one of which employs both room and pillar and longwall mining) and 12 surface (with eight highwall miners in operation) in West Virginia, Kentucky and Virginia. The number of mines that we operate may vary from time to time depending on a number of factors, including the existing demand for and price of coal, exhaustion of economically recoverable reserves and availability of experienced labor.

Customers for our steam coal product include primarily electric power utility companies who use our coal as fuel for their steam-powered generators. Customers for our metallurgical coal include primarily steel producers who use our coal to produce coke, which is in turn used as a raw material in the steel manufacturing process.

Key statistics for 2007 include:

- Produced coal revenues increased by 8% to $2.1 billion on produced coal sales of 39.9 million tons.
- Net income increased by 130% to $94.1 million.
- Reserve base of 2.3 billion tons.

A.T. Massey was originally incorporated in Richmond, Virginia in 1920 as a coal brokering business. In the late 1940s, A.T. Massey expanded its business to include coal mining and processing. In 1974, St. Joe Minerals acquired a majority interest in A.T. Massey. In 1981, St. Joe Minerals was acquired by Fluor Corporation. A.T. Massey was wholly owned by Fluor Corporation from 1987 until November 30, 2000. On November 30, 2000, we completed a reverse spin-off (the "Spin-Off") which separated Fluor Corporation into two entities: the "new" Fluor Corporation ("New Fluor") and Fluor Corporation which retained our coal-related businesses and was subsequently renamed Massey Energy Company. Massey Energy Company has been a separate, publicly traded company since December 1, 2000.

Industry Overview

Coal is the second most widely used form of energy in the United States, accounting for nearly one-fourth of the nation's total energy consumption, according to the BP Statistical Review of World Energy ("BP"), June 2007. In 2006, coal was the fuel source of 50% of the electricity generated nationwide, as reported by the Energy Information Administration ("EIA"), a statistical agency of the United States Department of Energy.

The United States is the second largest coal producer in the world, exceeded only by China. Other leading coal producers include India, Australia, South Africa, Russia and Indonesia. The United States has the largest coal reserves in the world, with proved reserves totaling 247 billion tons. Russia ranks second in proved coal reserves with 157 billion tons, followed by China with 115 billion tons, according to BP.

United States coal reserves are more plentiful than oil or natural gas with 234 years of supply at current production rates. Proved United States reserves of oil amount to 12 years of supply at current consumption rates and proved United States reserves of natural gas amount to 11 years of supply at current levels of consumption, as reported by the BP study.

United States coal production has more than doubled over the last 40 years. In 2006, total United States coal production, as estimated by the EIA, was 1.2 billion tons. The primary producing regions by tons were as follows:

Region	% of Total
Powder River Basin	41%
Central Appalachia	20%
West (other than Powder River Basin)	13%
Midwest	13%
Northern Appalachia	12%
All other	1%
Total	100%

The EIA estimated that approximately 69% of United States coal was produced by surface mining methods. The remaining 31% was produced by underground mining methods, which include room and pillar mining and longwall mining (more fully described in Item 1. Business, under the heading "Mining Methods").

Coal is used in the United States by utilities to generate electricity, by steel companies to make steel products, and by a variety of industrial users to produce heat and to power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. Significant quantities of coal are also exported from both East and Gulf Coast terminals. The breakdown of 2006 United States coal consumption, as estimated by the EIA, is as follows:

End Use	% of Total
Electric Power	93%
Other Industrial	5%
Coke	2%
Residential and Commercial	<1%
Total	100%

Coal has long been favored as an electricity generating fuel because of its basic economic advantage. The largest cost component in electricity generation is fuel. This fuel cost is typically lower for coal than competing fuels such as oil and natural gas on a Btu-comparable basis. Platts, which provides global commodity news and information, estimated the average total production costs of electricity, using coal and competing generation alternatives in 2006 as follows:

Electricity Generation Source	Cost per million Kilowatt Hours
Oil	$ 14.69
Natural Gas	$ 7.97
Coal	$ 2.19
Nuclear	$ 1.84

There are factors other than fuel cost that influence each utility's choice of electricity generation mode, including facility construction cost, access to fuel transportation infrastructure, environmental restrictions, and other factors. The breakdown of United States electricity generation by fuel source in 2006, as estimated by EIA, is as follows:

Electricity Generation Source	% of Total Electricity Generation
Coal	50%
Nuclear	20%
Natural Gas	19%
Hydroelectric	7%
Oil and other (solar, wind, etc.)	4%
Total	100%

Demand for electricity has historically been driven by United States economic growth but it can fluctuate from year to year depending on weather patterns. In 2006, electricity consumption in the United States increased 0.2% but the average growth rate in the past decade was approximately 1.5% per year according to EIA estimates. Because coal-fired generation is used in most cases to meet base load requirements, coal consumption has generally grown at the pace of electricity demand growth.

According to the World Coal Institute ("WCI"), in 2006 the United States ranked seventh among worldwide exporters of coal. Australia was the largest exporter, with other major exporters including Indonesia, China, South Africa, Russia, Columbia and Canada. According to EVA, United States exports increased by 19% from 2006 to 2007. The usage breakdown for 2007 United States exports of 59 million tons was 45% for electricity generation and 55% for steel production. In 2007, United States coal exports were shipped to more than 30 countries. The largest purchaser of United States exported utility coal in 2007 continued to be Canada, which took 14.6 million tons or 55% of total utility coal exports. This was down 4% compared to the 15.2 million tons exported to Canada in 2006. Overall steam coal exports increased 22% in 2007 compared to 2006. The largest purchasers of United States exported metallurgical coal were Brazil, which imported approximately 6.5 million tons, or 20%, and Canada, which imported 3.7 million tons, or 12%. In total, metallurgical coal exports increased 16% in 2007 compared to 2006.

Depending on the relative strength of the United States dollar versus currencies in other coal producing regions of the world, United States producers may export more or less coal into foreign countries as they compete on price with other foreign coal producing sources. Likewise, the domestic coal market may be impacted due to the relative strength of the United States dollar to other currencies, as foreign sources could be cost-advantaged based on a coal producing region's relative currency position. During 2007, the United States dollar weakened, making imported coal less competitive with United States produced coal, and positively impacting the competitiveness of United States exports in some overseas markets.

From 2003 to February 2008, the global marketplace for coal experienced swings in the demand/supply balance. In periods of supply shortfall, as occurred from 2003 to early 2006 and again in late 2007 through February 2008, the prices for coal reached record highs in the United States. Increased worldwide demand has been primarily driven by higher prices for oil and natural gas and economic expansion, particularly in China, India and elsewhere in Asia. At the same time, infrastructure and regulatory limitations in China contributed to a tightening of worldwide coal supply, affecting global prices of coal. The growth in China and India caused an increase in worldwide demand for raw materials and a disruption of expected coal exports from China to Japan, Korea and other countries.

Metallurgical grade coal is distinguished by special quality characteristics that include high carbon content, volatile matter, low expansion pressure, low sulfur content, and various other chemical attributes. High vol met coal is also high in heat content (as measured in Btus), and therefore is desirable to utilities as fuel for electricity generation. Consequently, high vol met coal producers have the ongoing opportunity to select the market that provides maximum revenue and profitability. The premium price offered by steel makers for the metallurgical quality attributes is typically higher than the price offered by utility coal buyers that value only the heat content. The primary concentration of United States metallurgical coal reserves is located in the Central Appalachian region. EVA estimates that the Central Appalachian region supplied 89% of domestic metallurgical coal and 73% of United States exported metallurgical coal during 2006.

For utility coal buyers, the primary goal is to maximize heat content, with other specifications like ash content, sulfur content, and size varying considerably among different customers. Low sulfur coals, such as those produced in the western United States and in Central Appalachia, generally demand a higher price due to restrictions on sulfur emissions imposed by the Clean Air Act of 1963 ("Clean Air Act") and the volatility in SO_2 allowance prices that occurred in recent years when the demand for all specifications of coal increased. SO_2 allowances permit utilities to emit a higher level of SO_2 than otherwise required under the Clean Air Act regulations. The demand and premium price for low sulfur coal is expected to diminish as more utilities install scrubbers at their coal-fired plants.

Coal shipped for North American consumption is typically sold at the mine loading facility with transportation costs being borne by the purchaser. Offshore export shipments are normally sold at the ship-loading terminal, with the purchaser paying the ocean freight. According to the National Mining Association ("NMA"), approximately two-thirds of United States coal production in recent years was shipped via railroads. Final delivery to consumers often involves more than one transportation mode. A significant portion of United States production is delivered to customers via barges on the inland waterway system and ships loaded at Great Lakes ports.

Neither we nor any of our subsidiaries are affiliated with or have any investment in BP, EIA, EVA, Platts or WCI. We are a member of the NMA.

Mining Methods

We produce coal using four distinct mining methods: underground room and pillar, underground longwall, surface and highwall mining, which are explained as follows:

In the underground room and pillar method of mining, continuous mining machines cut three to nine entries into the coal bed and connect them by driving crosscuts, leaving a series of rectangular pillars, or columns of coal, to help support the mine roof and control the flow of air. Generally, openings are driven 20 feet wide and the pillars are 40 to 100 feet wide. As mining advances, a grid-like pattern of entries and pillars is formed. When mining advances to the end of a panel, retreat mining may begin. In retreat mining, as much coal as is feasible is mined from the pillars that were created in advancing the panel, allowing the roof to fall upon retreat. When retreat mining is completed to the mouth of the panel, the mined panel is abandoned.

In longwall mining (which is a type of underground mining), a shearer (cutting head) moves back and forth across a panel of coal typically about 1,000 feet in width, cutting a slice approximately 3.5 feet deep. The cut coal falls onto a flexible conveyor for removal. Longwall mining is performed under hydraulic roof supports (shields) that are advanced as the seam is cut. The roof in the mined out areas falls as the shields advance.

Surface mining is used to extract coal deposits found close to the surface. This method involves removal of overburden (earth and rock covering coal) with heavy earth moving equipment, including large shovels and draglines, and explosives, followed by extraction of coal from coal seams. After extraction of coal, disturbed parcels of land are reclaimed by replacing overburden and reestablishing vegetation and plant life.

Highwall mining is used in connection with surface mining. A highwall mining system consists of a remotely controlled continuous mining machine, which extracts coal and conveys it via augers or belt conveyors to the portal. The cut is typically a rectangular, horizontal opening in the highwall (the unexcavated face of exposed overburden and coal in a surface mine) 11-feet wide and reaching depths of up to 1,000 feet. Multiple, parallel openings are driven into the highwall, separated by narrow pillars that extend the full depth of the hole.

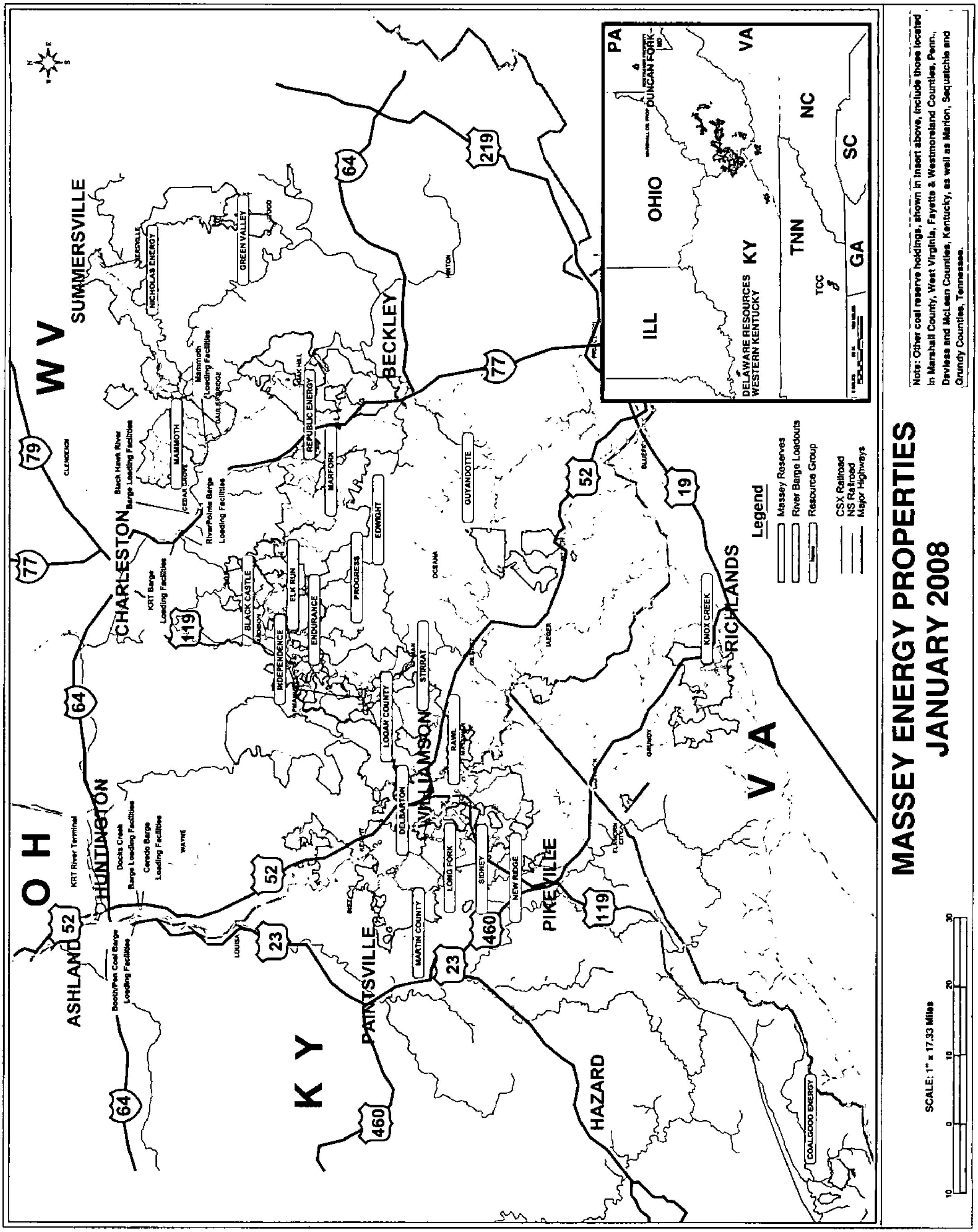
Use of continuous mining machines in the room and pillar method of underground mining represented approximately 41% of our 2007 coal production. Production from underground longwall mining operations constituted approximately 6% of our 2007 production. Surface mining represented approximately 47% of our 2007 coal production. Surface mines also use highwall mining systems to produce coal from high overburden areas. Highwall mining represented approximately 6% of our 2007 coal production.

Mining Operations

We currently have 22 distinct Resource Groups, including sixteen in West Virginia, five in Kentucky and one in Virginia. These complexes blend, process and ship coal that is produced from one or more mines, with a single complex handling the coal production of as many as seven distinct underground or surface mines. Our mines have been developed at strategic locations in close proximity to our preparation plants and rail shipping facilities.

We operate solely in the Central Appalachian region, which is the principal source of low sulfur bituminous coal in the United States, used for power generation, metallurgical coke production and industrial boilers. Central Appalachian coal accounted for 20% of 2007 United States coal production according to EIA.

The following map provides the location of our operations within the Central Appalachian region:



The following table provides key operational information on our Resource Groups in 2007:

Resource Group Name	Location (County)	Active/ Inactive	Mine Type	Active Mine Count [4]	Mining Equipment	Transportation	2007 Production [1]	2007 Shipments [2]	Year Established or Acquired
							(Thousands of Tons)		
West Virgina Resource Groups									
Black Castle	Boone	Active	S	1	HW	truck, barge	3,549	2,104	19
Delbarton	Mingo	Active	U	1		NS	801	905	19
Edwight	Raleigh	Active	S/U	2	HW	CSX	1,572	-	20
Elk Run	Boone	Active	U	5	LW	CSX	2,274	1,398	19
Endurance	Boone	Active	S	1	HW	CSX	1,368	727	20
Green Valley	Nicholas	Active	U	2		CSX	759	808	19
Guyandotte [3]	Wyoming	Active	U	1		NS	14	14	20
Independence	Boone	Active	U	3	LW	CSX	1,755	4,159	19
Logan County	Logan	Active	S/U	6	HW	CSX	3,783	3,722	19
Mammoth	Kanawha	Active	U	3		barge	1,431	2,039	20
Marfork	Raleigh	Active	U	7		CSX	3,817	6,656	19
Nicholas Energy	Nicholas	Active	S/U	2	HW	NS	3,362	3,039	19
Progress	Boone	Active	S	1		CSX	5,125	4,529	19
Rawl	Mingo	Active	U	2		NS	1,044	104	19
Republic Energy	Raleigh	Active	S	1		truck	1,564	1,150	20
Stirrat	Logan	Active	S	1		CSX	1,359	1,890	19
Kentucky Resource Groups									
Coalgood Energy	Harlan	Inactive				CSX	2	13	20
Long Fork	Pike	Active				NS	-	1,641	19
Martin County	Martin	Inactive				NS	242	270	19
New Ridge	Pike	Active				CSX	-	504	19
Sidney	Pike	Active	S/U	7	HW	NS	4,932	3,457	19
Virginia Resource Group									
Knox Creek	Tazewell	Active	U	1		NS	706	724	19
Total				47			39,459	39,853	

(1) For purposes of this table, coal production has been allocated to the Resource Group where the coal is mined, rather than the Resource Group where the coal is processed and shipped. Production amounts above represent coal extracted from the ground.
(2) For purposes of this table, coal shipments have been allocated to the Resource Group from where the coal is processed and shipped, rather than the Resource Group where the coal is mined.
(3) Previously known as Kepler.
(4) Active mine count as of January 31, 2008.
S – surface mine
U – underground mine
HW – highwall miners operated in conjunction with surface mines
LW – longwall mine
NS – Norfolk Southern Railway Company
CSX – CSX Transportation

The following descriptions of the Resource Groups are current as of January 31, 2008.

West Virginia Resource Groups

Black Castle. The Black Castle complex includes a large surface mine, two highwall miners, the Homer III direct-ship loadout, a stoker plant, and the Omar preparation plant. Some of the surface mine coal is trucked to the stoker plant where the coal is crushed and screened. The stoker product is trucked to river docks for barge delivery or trucked directly to customers. A portion of the coal is transported to the Omar plant via an underground belt conveyor system, where it is crushed and shipped to customers or, if the coal needs processing, it is belted to the preparation plant at the Independence Resource Group for processing and shipment. The Omar preparation plant was not utilized for processing coal in 2006. The direct-ship facility at the preparation plant can crush 500 tons per hour and the preparation plant can process 800 tons per hour. The Omar preparation plant serves CSX rail system customers with unit train shipments of up to 110 railcars. Coal is also trucked to the Homer III loadout where it is crushed and shipped to customers by rail, trucked to river docks for barge delivery, or trucked directly to customers. The Homer III loadout serves CSX rail system customers with unit train shipments of up to 100 railcars.

Delbarton. The Delbarton complex includes one underground room and pillar mine and a preparation plant. Production from the mine is transported to the Delbarton preparation plant via overland conveyor. The Delbarton preparation plant also processes coal from two surface mines of the Logan County Resource Group. The Delbarton preparation plant can process 600 tons per hour. The clean coal product is shipped to customers via the Norfolk Southern railway in unit trains of up to 110 railcars.

Edwight. The Edwight complex includes one underground room and pillar mine, a surface mine, a highwall miner and the Goals preparation plant. Production from all of the mines is transported via conveyor system to the Goals preparation plant. The Goals preparation plant can process 800 tons per hour. The rail loading facility serves CSX railway customers with unit trains of up to 100 railcars.

Elk Run. The Elk Run complex produces coal from four underground room and pillar mines and the Logans Fork longwall. All of the room and pillar mines belt coal to the Elk Run preparation plant, while the longwall belts coal to the preparation plant of the Marfork Resource Group. Additionally, Elk Run processes coal produced by surface mines of the Progress Resource Group and transported via underground conveyor system. The Elk Run preparation plant has a processing capacity of 2,200 tons per hour. Elk Run also operates a 200 ton per hour stoker facility that produces screened, small dimension coal for certain of our industrial customers. Customer shipments are loaded on the CSX rail system in unit trains of up to 150 railcars.

Endurance. The Endurance complex includes a surface mine, highwall miner and a direct-ship loadout. A portion of the production from the surface mine is loaded for shipment to customers at the direct ship loadout and the remainder is trucked to a conveyor system, which transports the coal to the preparation plant at the Independence Resource Group for processing.

Green Valley. The Green Valley complex includes two underground room and pillar mines and a preparation plant. The Green Valley preparation plant, which has a processing capacity of 600 tons per hour, receives coal from the mines via trucks. The rail loading facility services customers on the CSX rail system with unit train shipments of up to 75 railcars.

Guyandotte. The Guyandotte complex, formerly known as Kepler, includes one underground room and pillar mine. The mine trucks coal to a third-party preparation plant for washing and shipment to customers via the Norfolk Southern railway system.

Independence. The Independence complex includes the Revolution longwall mine, two underground room and pillar mines and a preparation plant. Production from the underground mines is transported via overland conveyor system to the Independence preparation plant. The Black Castle surface mine and highwall miner and the surface mine at the Endurance Resource Group transport coal requiring processing to the Independence preparation plant via conveyor system. The Independence plant has a processing capacity of 2,200 tons per hour. Customers are served via rail shipments on the CSX rail system in unit trains of up to 150 railcars.

Logan County. The Logan County complex includes four surface mines, one highwall miner and two underground room and pillar mines, plus the Bandmill preparation plant and the Feats loadout, all on the CSX rail system. The surface mines and the highwall miners deliver coal to the Bandmill plant via truck and conveyor system, while both underground mines belt coal directly to this plant. The Feats loadout can service customers via the CSX rail system with unit train shipments of up to 80 cars. The Bandmill preparation plant has a processing capacity of 1,800 tons per hour. The Bandmill rail loading facility services customers via the CSX rail system with unit train shipments of up to 150 railcars.

Mammoth. The Mammoth complex operates three underground room and pillar mines and a preparation plant. Coal is transported to the preparation plant, with two mines using on-highway trucks and one mine using a conveyor system. The plant has a 1,200 tons per hour processing facility capacity with barge loading capabilities on the upper Kanawha River.

Marfork. The Marfork complex includes seven underground room and pillar mines and a preparation plant. Production from six of the mines is belted directly to the preparation plant via conveyor while the remainder is trucked on private haul roads to the preparation plant. The Marfork preparation plant has a capacity of 2,400 tons per hour. Customers are served via the CSX rail system with unit trains of up to 150 railcars.

Nicholas Energy. The Nicholas Energy complex includes an underground room and pillar mine, a large surface mine, two highwall miners and a preparation plant. Coal from the underground mine is transported to the preparation plant for processing via conveyor system. Coal from the highwall miners and the portion of surface mined coal requiring processing is transported to the preparation plant using off-road trucks. Coal not requiring processing is transported via off road trucks to a conveyor system that moves the coal directly to a rail loadout facility. The plant has a processing capacity of 1,200 tons per hour. Coal shipments are loaded into rail cars for delivery via the Norfolk Southern railway in unit trains of up to 140 railcars, or are transported via on-highway trucks to the Mammoth Resource Group's barge loading facility.

Progress. The Progress complex includes the large Twilight MTR surface mine. A dragline is also utilized at the Twilight MTR surface mine. Production from the Twilight MTR surface mine is transported via underground conveyor to the Elk Run Resource Group for processing and rail shipment.

Rawl. The Rawl complex includes two underground room and pillar mines and a preparation plant. Production from the mines is transported via truck to the preparation plant of the Stirrat Resource Group. The Rawl plant, which was idled in December 2006, has a throughput capacity of 1,450 tons per hour. Customers are served via the Norfolk Southern railway with unit trains of up to 150 railcars.

Republic Energy. The Republic Energy complex consists of one surface mine. Direct-ship coal is trucked using on-highway trucks to various docks on the Kanawha River for barge delivery to customers and to the Marfork Resource Group for rail delivery to customers. Coal requiring processing is trucked using on-highway trucks to Mammoth Resource Group's preparation plant for processing and barge delivery to customers.

Stirrat. The Stirrat complex includes one surface mine, a preparation plant and the Superior loadout. The surface mine belts coal directly to two 12,500 ton silos at the Superior loadout. The Superior loadout serves CSX railway customers with unit trains of up to 100 railcars. The Stirrat preparation plant cleans coal from two adjacent underground room and pillar mines of the Rawl Resource Group. The plant has a rated capacity of 600 tons per hour. Customers are served via the CSX rail system with unit trains of up to 100 railcars.

Kentucky Resource Groups

Coalgood Energy. The Coalgood Energy complex, which was idled in January 2007, includes one surface mine and a direct-ship loadout. When in operation, the coal is trucked off-road to the loadout, which serves CSX railway customers with unit trains of up to 75 railcars. Although no firm plans have been made, we continue to evaluate options for the complex, which may include a resumption of operations, allowing it to remain idle or pursuing disposal alternatives.

Long Fork. The Long Fork preparation plant processes coal produced by two underground room and pillar mines of the Sidney Resource Group. All production is transported via conveyor system to the Long Fork preparation plant for processing and shipping to customers. The Long Fork plant has a rated capacity of 1,500 tons per hour. The rail loading facility services customers on the Norfolk Southern railway with unit trains of up to 150 railcars.

Martin County. The Martin County complex, which was idled in January 2007, has historically produced coal from underground and surface mines. Direct-ship coal production from the surface mines was shipped to river docks via truck. Coal requiring processing was transported by conveyor belt or truck to the preparation plant. Martin County's preparation plant has a throughput capacity of 1,500 tons per hour, although the throughput capacity is limited due to decreased impoundment availability. The coal from the preparation plant can be shipped either via the Norfolk Southern railway in unit trains of up to 125 railcars or to river docks via truck. Although no firm plans have been made, we continue to evaluate options for the complex, which may include a resumption of operations, allowing it to remain idle or pursuing disposal alternatives.

New Ridge. The New Ridge complex loads clean coal that is transported via truck from the preparation plant of the Sidney Resource Group and coal trucked directly from Sidney's surface mine. The New Ridge preparation plant has a capacity of 800 tons per hour. The preparation plant is currently idle but may be reactivated from time to time during 2008 as needed. All coal is loaded for shipment to customers via the CSX rail system in unit trains of up to 100 railcars.

Sidney. The Sidney complex includes six underground room and pillar mines, one surface mine, a highwall miner and a preparation plant. Two of the underground mines transport coal via underground conveyor system to the Long Fork Resource Group for processing and shipment, and the remainder of the underground mines transport production via underground conveyor system or truck to Sidney's preparation plant. A portion of the coal from Sidney's preparation plant and coal from the surface mines are trucked to the New Ridge Resource Group for loading into railroad cars. Sidney's preparation plant has a capacity of 1,500 tons per hour. The rail loading facility at the preparation plant serves customers on the Norfolk Southern rail system with unit trains of up to 140 railcars.

Virginia Resource Group

Knox Creek. The Knox Creek complex includes one underground room and pillar mine and a preparation plant. Production from the mine is belted by conveyor system to the preparation plant. The preparation plant has a feed capacity of 650 tons per hour. The preparation plant serves customers on the Norfolk Southern rail system with unit trains of up to 100 railcars.

Coal Reserves

We estimate that, as of December 31, 2007, we had total recoverable reserves of approximately 2.3 billion tons consisting of both proven and probable reserves. "Reserves" are defined by the SEC Industry Guide 7 as that part of a mineral deposit, which could be economically and legally extracted or produced at the time of the reserve determination. "Recoverable" reserves means coal that is economically recoverable using existing equipment and methods under federal and state laws currently in effect. Approximately 1.5 billion tons of reserves are classified as proven reserves. "Proven (measured) reserves" are defined by the SEC Industry Guide 7 as 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. The remaining 0.8 billion tons of our reserves are classified as probable reserves. "Probable reserves" are defined by the SEC Industry Guide 7 as reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our internal engineers, geologists and finance associates. Reserve estimates are updated annually using geologic data taken from drill holes, adjacent mine workings, outcrop prospect openings and other sources. Coal tonnages are categorized according to coal quality, seam thickness, mineability and location relative to existing mines and infrastructure. In accordance with applicable industry standards, proven reserves are those for which reliable data points are spaced no more than 2,700 feet apart. Probable reserves are those for which reliable data points are spaced 2,700 feet to 7,900 feet apart. Further scrutiny is applied using geological criteria and other factors related to profitable extraction of the coal. These criteria include seam height, roof and floor conditions, yield and marketability.

As with most coal-producing companies in Central Appalachia, the majority of our coal reserves are controlled pursuant to leases from third party landowners. These leases convey mining rights to the coal producer in exchange for a per ton or percentage of gross sales price royalty payment to the lessor. However, approximately 18% of our reserve holdings are owned and require no royalty or per ton payment to other parties. Royalty expense for coal reserves from our producing properties (owned and leased) was approximately 4.1% of Produced coal revenue for the year ended December 31, 2007.

The following table provides proven and probable reserve data by "status" (i.e., location, owned or leased, assigned or unassigned, etc.) as of December 31, 2007:

Resource Group	Location (2)	Recoverable Reserves (1) Total	Proven	Probable	Assigned (3)	Unassigned (3)	Owned	Leased
		(In Thousands of Tons)						
West Virginia								
Black Castle	Boone County	88,756	61,609	27,147	41,490	47,266	1,920	86,836
Delbarton	Mingo County	286,747	120,442	166,305	141,249	145,498	25	286,722
Edwight	Raleigh County	8,870	8,870	-	8,870	-	-	8,870
Elk Run	Boone County	162,767	125,451	37,316	58,403	104,364	4,660	158,107
Endurance	Boone County	25,126	25,126	-	24,998	128	24,560	566
Green Valley	Nicholas County	7,135	7,135	-	7,135	-	-	7,135
Guyandotte	Wyoming County	43,603	15,266	28,337	-	43,603	330	43,273
Independence	Boone County	43,311	42,001	1,310	29,852	13,459	9,482	33,829
Logan County	Logan County	73,529	68,881	4,648	49,883	23,646	-	73,529
Mammoth	Kanawha County	87,558	67,224	20,334	74,244	13,314	42,844	44,714
Marfork	Raleigh County	121,721	109,411	12,310	79,125	42,596	815	120,906
Nicholas Energy	Nicholas County	92,303	52,461	39,842	49,897	42,406	38,514	53,789
Progress	Boone County	22,446	22,446	-	22,446	-	-	22,446
Rawl	Mingo County	96,369	68,600	27,769	59,270	37,099	1,333	95,036
Republic Energy	Raleigh County	38,209	34,387	3,822	38,209	-	-	38,209
Stirrat	Logan County	5,293	3,476	1,817	412	4,881	-	5,293
Kentucky								
Coalgood Energy	Harlan County	21,261	12,357	8,904	-	21,261	2,704	18,557
Long Fork	Pike County	4,964	2,764	2,200	264	4,700	-	4,964
Martin County	Martin County	42,554	25,865	16,689	2,783	39,771	1,336	41,218
New Ridge	Pike County	-	-	-	-	-	-	-
Sidney	Pike County	127,055	73,055	54,000	101,938	25,117	7,028	120,027
Virginia								
Knox Creek	Tazewell County	45,087	32,942	12,145	29,354	15,733	-	45,087
Subtotal		1,444,664	979,769	464,895	819,822	624,842	135,551	1,309,113
Land Management Companies: (4)								
Black King	Boone County, WV Raleigh County, WV	32,666	32,666	-	1,155	31,511	17,428	15,238
Boone East	Boone County, WV Kanawha County, WV	132,145	96,131	36,014	6,180	125,965	64,721	67,424
Boone West	Lincoln County, WV Logan County, WV	252,332	98,556	153,776	10,346	241,986	65,553	186,779
Ceres Land	Raleigh County, WV	33,351	24,220	9,131	-	33,351	-	33,351
Duncan Fork	Various counties, PA	94,086	44,449	49,637	-	94,086	79,907	14,179
Lauren Land	Mingo County, WV Logan County, WV Various counties, KY	181,247	119,729	61,518	11,175	170,072	18,011	163,236
New Market Land	Wyoming County, WV	7,984	4,790	3,194	-	7,984	102	7,882
Raven Resources	Raleigh County, WV Boone County, WV	18,978	18,978	-	-	18,978	-	18,978
Tennessee Consolidated Coal	Various counties, TN	26,907	1,332	25,575	-	26,907	24,054	2,853
Subtotal		779,696	440,851	338,845	28,856	750,840	269,776	509,920
Other	N/A	59,000	38,303	20,697	24,140	34,860	1,288	57,712
Total		2,283,360	1,458,923	824,437	872,818	1,410,542	406,615	1,876,745

(1) Recoverable reserves represent 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 under current law.

(2) All of the recoverable reserves listed are in Central Appalachia, except for the Duncan Fork reserves, which are located in Northern Appalachia and Lauren Land reserves, a portion of which are located in the Illinois Basin. The reserve numbers of each Resource Group contain a moisture factor specific to the particular reserve: that Resource Group. The moisture factor represents the average moisture present in our delivered coal.

(3) Assigned Reserves represent recoverable reserves that are dedicated to a specific permitted mine; otherwise, the reserves are considered Unassigned. For Land Management Companies, Assigned Reserves have been leased to a third party and are dedicated to a specific permitted mine of the lessee.

(4) Land management companies are our subsidiaries whose primary purposes are to acquire and hold our reserves.

The categorization of the "quality" (i.e., sulfur content, Btu, coal type, etc.) of coal reserves is as follows:

Recoverable Reserves (1)

	Recoverable Reserves	Sulfur Content +1% (2)	Sulfur Content -1% (2)	Compliance	Avg. Btu as Received (3)	Coal Type (4)
	(In Thousands of Tons Except Average Btu as Received)					
Resource Groups:						
West Virginia						
Black Castle	88,756	35,404	53,352	22,921	12,000	Utility and Industrial
Delbarton	286,747	111,954	174,793	127,073	12,500	High Vol Met, Utility, and Industrial
Edwight	8,870	1,555	7,315	7,315	12,800	High Vol Met, Utility, and Industrial
Elk Run	162,767	80,695	82,072	73,177	13,400	High Vol Met, Utility, and Industrial
Endurance	25,126	4,952	20,174	10,047	12,500	Utility and Industrial
Green Valley	7,135	921	6,214	6,214	13,100	High Vol Met, Utility, and Industrial
Guyandotte	43,603	-	43,603	43,603	13,800	Low Vol Met
Independence	43,311	14,958	28,353	3,046	13,100	High Vol Met, Utility, and Industrial
Logan County	73,529	21,665	51,864	41,920	12,500	High Vol Met, Utility, and Industrial
Mammoth	87,558	5,216	82,342	41,706	12,000	Utility and Industrial
Marfork	121,721	54,597	67,124	42,808	13,150	High Vol Met, Utility, and Industrial
Nicholas Energy	92,303	41,683	50,620	31,957	11,800	Utility and Industrial
Progress	22,446	2,316	20,130	17,809	12,400	High Vol Met, Utility, and Industrial
Rawl	96,369	31,128	65,241	42,416	12,600	High Vol Met, Utility, and Industrial
Republic	38,209	6,154	32,055	22,352	12,400	High Vol Met and Utility
Stirrat	5,293	-	5,293	5,293	13,800	High Vol Met, Utility, and Industrial
Kentucky						
Coalgood Energy	21,261	4,712	16,549	11,680	11,900	High Vol Met, Utility, and Industrial
Long Fork	4,964	3,500	1,464	-	12,500	Utility and Industrial
Martin County	42,554	31,939	10,615	4,629	12,000	Utility and Industrial
New Ridge	-	-	-	-	-	N/A
Sidney	127,055	49,933	77,122	54,177	12,500	High Vol Met, Utility, and Industrial
Virginia						
Knox Creek	45,087	-	45,087	45,087	13,300	High Vol Met, Utility, and Industrial
Subtotal	1,444,664	503,282	941,382	655,230		
Land Management Companies: (5)						
Black King	32,666	15,570	17,096	13,799	13,300	High Vol Met and Utility
Boone East	132,145	33,250	98,895	32,978	13,100	High Vol Met, Utility, and Low Vol Met
Boone West	252,332	133,849	118,483	79,369	13,100	High Vol Met and Utility
Ceres Land	33,351	5,991	27,360	12,740	13,000	High Vol Met and Utility
Duncan Fork	94,086	94,086	-	-	13,600	High Vol Met, Utility, and Industrial
Lauren Land	181,247	85,460	95,787	72,787	12,400	High Vol Met and Utility
New Market Land	7,984	-	7,984	7,984	13,600	High Vol Met and Low Vol Met
Raven Resources	18,978	7,449	11,529	1,369	13,100	High Vol Met and Utility
Tennessee Consolidated Coal	26,907	20,353	6,554	4,816	12,800	High Vol Met, Utility and Industrial
Subtotal Land Management	779,696	396,008	383,688	225,842		
Other	59,000	6,638	52,362	47,214	13,000	Various
Total	2,283,360	905,928	1,377,432	928,286		

(1) The reserve numbers of each Resource Group contain a moisture factor specific to the particular reserves of that Resource Group. The moisture factor represents the average moisture present in our delivered coal.
(2) +1% or -1% refers to sulfur content as a percentage in coal by weight. Compliance coal is less than 1% sulfur content by weight and is included in the -1% column.
(3) Represents an estimate of the average Btu per pound present in our coal, as it is received by the customer.
(4) Reserve holdings include metallurgical coal reserves. Although these metallurgical coal reserves receive the highest selling price in the current coal market when marketed to steel-making customers, they can also be marketed as an ultra high Btu, low sulfur utility coal for electricity generation.
(5) Land management companies are our subsidiaries whose primary purposes are to acquire and hold our reserves.

Compliance compared to non-compliance coal

Coals are sometimes characterized as compliance or non-compliance coal. The phrase compliance coal, as it is commonly used in the coal industry, refers to compliance only with sulfur dioxide emissions standards imposed by Title IV of the Clean Air Act and indicates that when burned, the coal will produce emissions that will meet the current standard without further cleanup. A coal that is considered a compliance coal for meeting sulfur dioxide standards may not meet an emission standard for a different pollutant such as mercury. Moreover, the term compliance coal is always used with reference to the then-current regulatory limit. Clean air regulations that further restrict sulfur dioxide emissions will likely reduce significantly the amount of coal that can be labeled compliance. Currently, coal classified as compliance will meet the power plant emission standard of 1.2 pounds of sulfur dioxide per million Btu's of fuel consumed. At December 31, 2007, approximately 0.9 billion tons, or 41%, of our coal reserves met the current standard as compliance coal.

Distribution

We employ transportation specialists who negotiate freight and terminal agreements with various providers, including railroads, barge lines, ocean-going vessels, bulk motor carriers and terminal facilities. Transportation specialists also coordinate with customers, mining facilities and transportation providers to establish shipping schedules that meet each customer's needs.

Our 2007 shipments of 39.9 million tons were loaded from 22 mining complexes. Rail shipments constituted 90% of total shipments, with 25% loaded on Norfolk Southern trains and 65% loaded on CSX trains. The balance was shipped from mining complexes via truck or barge.

Approximately 20% of production was ultimately delivered via the inland waterway system. Coal is loaded directly into barges, or is transported by rail or truck to docks on the Ohio, Big Sandy and Kanawha Rivers and then ultimately transported by barge to electric utilities, integrated steel producers and industrial consumers served by the inland waterway system. We also moved approximately 4% of our production to Great Lakes' ports for transport to various United States and Canadian customers.

Customers and Coal Contracts

We have coal supply commitments with a wide range of electric utilities, steel manufacturers, industrial customers and energy traders and brokers. By offering coal of both steam and metallurgical grades, we are able to serve a diverse customer base. This market diversity allows us to adjust to changing market conditions and sustain high sales volumes. The majority of our customers purchase coal for terms of one year or longer, but we also supply coal on a spot basis for some customers. Our largest customer, American Electric Power Company, Inc. and its affiliates, accounted for 11% of total fiscal year 2007 Produced coal revenue.

As is customary in the coal industry, we enter into long-term contracts (one year or more in duration) with many of our customers. These arrangements allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. Long-term contracts are a result of extensive negotiations with customers. As a result, the terms of these contracts vary with respect to price adjustment mechanisms, pricing terms, permitted sources of supply, force majeure provisions, quality adjustments and other parameters. Some of the contracts contain price adjustment mechanisms that allow for changes to prices based on statistics from the United States Department of Labor. Coal quality specifications may be especially stringent for steel customers.

For the year ended December 31, 2007, approximately 95% of coal sales volume was pursuant to long-term contracts. We anticipate that in 2008, coal sales volume percentage pursuant to long-term arrangements will be comparable to 2007. As of February 14, 2008, we had contractual sales commitments of approximately 123 million tons, including commitments subject to price reopener and/or optional tonnage provisions. Remaining contractual terms of our sales commitments range from one to 12 years with an average volume-weighted remaining term of approximately 2.3 years. Eighty-four percent of the contracted sales tons are priced. As of February 14, 2008, we have committed most of our expected 2008 production. In addition, we purchase coal from third-party coal producers from time to time to supplement production and resell this coal to customers.

Suppliers

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

Competition

The coal industry in the United States and overseas is highly competitive, with numerous producers selling into all markets that use coal. We compete against large and small producers in the United States and overseas. The NMA estimated that in 2006 there were 25 coal companies in the United States with annual production in excess of 5 million tons, which together account for approximately 84% of United States production. According to the EIA, we were the sixth largest coal company in terms of tons produced in 2006, exceeded by Peabody Energy Corporation ("Peabody"), Rio Tinto Energy America, Inc., Arch Coal, Inc. ("Arch"), CONSOL Energy Inc. ("CONSOL"), and Foundation Coal Holdings Inc. ("Foundation") . However, according to company reports, we were the fourth largest United States coal company in terms of revenue in 2006, exceeded by Peabody, CONSOL and Arch.

We compete with other producers primarily on the basis of price, coal quality, transportation cost and reliability of supply. Continued demand for coal is also dependent on factors outside of our control, including demand for electricity and steel, general economic conditions, environmental and governmental regulations, weather, technological developments, and the availability and cost of alternative fuel sources. We sell coal to foreign electricity generators and to the more specialized metallurgical coal market, both of which are significantly affected by international demand and competition.

Historically, global coal markets have responded to increased demand and higher prices for coal by increasing production and supply. In recent years, however, capacity expansion has been somewhat limited by the increased costs of mining, high capital requirements, coal seam degradation, reserve depletion, labor shortages, transportation issues related to rail, barge and truck shipments, higher costs related to compliance with new and increasingly stringent regulations, the difficulty of obtaining permits and bonding, and other factors. While these constraints persist in major coal producing countries and regions, periods of supply and demand imbalance may be extended and increased pricing volatility, particularly upward, may result.

Other Related Operations

We have other related operations and activities in addition to our normal coal production and sales business. The following business activities are included in this category:

Coal Handling Joint Venture. We hold a 50% interest in a joint venture that owns and operates third-party end-user coal handling facilities. Certain subsidiaries currently operate the coal handling facilities for the joint venture.

Gas Operations. We hold interests in operations that produce, gather and market natural gas from shallow reservoirs in the Appalachian Basin. In the eastern United States, conventional natural gas reservoirs are located in various types of sedimentary formations at depths ranging from 2,000 to 15,000 feet. The depths of the reservoirs drilled and operated by us range from 2,500 to 5,600 feet.

Nearly all of our gas production is from operations in southern West Virginia. In this region, we own and operate approximately 188 wells, 200 miles of gathering line, and various small compression facilities. Our southern West Virginia operations control approximately 27,000 acres of drilling rights. In addition, we own a majority working interest in 48 wells operated by others, and minority working interests in approximately 30 wells operated by others. The December 2007 average daily production, from the 236 wells owned or controlled, was 1.9 million cubic feet per day. We do not consider our current gas production level, revenues or costs to be material to our cash flows, results of operations or financial condition.

Other. From time to time, we also engage in the sale of certain non-strategic assets such as timber, oil and gas rights, surface properties and reserves. In addition, we have established several contractual arrangements with customers where services other than coal supply are provided on an ongoing basis. None of these contractual arrangements is considered to be material. Examples of such other services include arrangements with several metallurgical and industrial customers to coordinate shipment of coal to their stockpiles, maintain ownership of the coal inventory on their property and sell tonnage to them as it is consumed. We work closely with customers to provide other services in response to the current needs of each individual customer.

Marketing and Sales

Our marketing and sales force, based in the corporate office in Richmond, Virginia, includes sales managers, distribution/traffic managers and administrative personnel.

During the year ended December 31, 2007, we sold 39.9 million tons of produced coal for total Produced coal revenue of $2.1 billion. The breakdown of produced tons sold by market served was 69% utility, 21% metallurgical and 10%

industrial. Sales were concluded with over 100 customers. Export shipment revenue totaled approximately $330.7 million, representing approximately 16.1% of 2007 Produced coal revenue. In 2007, we exported shipments to customers in 12 countries across the globe, which included Brazil, Canada, Egypt, Finland, Germany, India, Japan, Italy, Netherlands, South Korea, Spain and Sweden. Sales are made in United States dollars, which minimizes foreign currency risk.

Employees and Labor Relations

As of December 31, 2007, we had 5,407 employees, including 108 employees affiliated with the United Mine Workers of America ("UMWA"). Relations with employees are generally good, and there have been no material work stoppages in the past ten years.

Environmental, Safety and Health Laws and Regulations

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, permitting 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, water appropriation and legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, endangered plant and wildlife protection, limitations on land use, and storage of petroleum products and substances that are regarded as hazardous under applicable laws. The possibility exists that new legislation or regulations may be adopted that could have a significant impact on our mining operations or on our customers' ability to use coal.

Numerous governmental permits and approvals are required for mining operations. Regulations provide that a mining permit or modification can be delayed, refused or revoked if an officer, director or a stockholder with a 10% or greater interest in the entity is affiliated with or is in a position to control another entity that has outstanding permit violations. Thus, past or ongoing violations of federal and state mining laws by individuals or companies no longer affiliated with us could provide a basis to revoke existing permits and to deny the issuance of addition permits. We are required to prepare and present to federal, state or local authorities data and/or analysis pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment, public and employee health and safety. All requirements imposed by such authorities may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. Accordingly, the permits we need for our mining and gas operations may not be issued, or, if issued, may not be issued in a timely fashion. Permits we need may involve requirements that may be changed or interpreted in a manner that restricts our ability to conduct our mining operations or to do so profitably. Future legislation and administrative regulations may increasingly emphasize the protection of the environment, health and safety and, as a consequence, our activities may be more closely regulated. Such legislation and regulations, as well as future interpretations of existing laws, may require substantial increases in equipment and operating costs, delays, interruptions or a termination of operations, the extent of which cannot be predicted.

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 surety performance bonds or letters of credit pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, often 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. We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, even with our substantial efforts to comply with extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time. In 2007, the EPA filed suit against us and twenty-seven of our subsidiaries alleging violations of the Federal Clean Water Act. In January 2008, we announced that we had agreed with the EPA to settle the lawsuit for a payment of $20 million in penalties (see Note 17 to the Notes to Consolidated Financial Statements). In 2007, we spent approximately $23.1 million to comply with environmental laws and regulations, of which $13.8 million was for reclamation, including $11.1 million for final reclamation. None of these expenditures were capitalized. We anticipate spending approximately $38.8 million and $31.7 million in such non-capital expenditures in 2008 and 2009, respectively. Of these expenditures, $29.3 million and $22.0 million for 2008 and 2009, respectively, are anticipated to be for reclamation.

Emission Control Technology. We own a majority interest in Coalsolv, LLC, which holds the United States marketing rights for the coal-fired plant emission control technologies developed by Cansolv Technologies, Inc., in which we hold a minority interest. Cansolv's technologies remove sulfur dioxide (SO_2), nitrogen oxide (NO_x), mercury, carbon dioxide (CO_2), and other greenhouse gases from flue gas emissions. The Cansolv process has been utilized at various industrial facilities around the world, with additional projects underway in China and Canada. Through Coalsolv, we contributed funds for a pilot plant that has been utilized in the United States and Canada for the testing and piloting of the Cansolv SO_2, NO_X, mercury, and CO_2 capture technology on coal-fired power plants.

Mine Safety and Health

Stringent health and safety standards have been in effect since Congress enacted the Federal Coal Mine Health and Safety Act of 1969. The Federal Coal Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed safety and health standards on all aspects of mining operations. A further expansion occurred in June 2006 with the enactment of the Mine Improvement and New Emergency Response Act of 2006 ("MINER Act").

The MINER Act and related Mine Safety and Health Administration ("MSHA") regulatory action require, among other things, improved emergency response capability, increased availability of emergency breathable air, enhanced communication and tracking systems, more available mine rescue teams, increased mine seal strength and monitoring of sealed areas in underground mines, as well as larger penalties by MSHA for noncompliance by mine operators. Coal producing states, including West Virginia and Kentucky, passed similar legislation. The bituminous coal mining industry was actively engaged throughout 2007 in activities to achieve compliance with these new requirements. These compliance efforts will continue into 2008.

On February 8, 2008, MSHA published a final rule that revises existing standards for mine rescue teams for underground coal mines. This final rule implements Section 4 of the MINER Act to improve overall mine rescue capability, mine emergency response time and mine rescue team effectiveness. It also calls for increased quantity and quality of mine rescue team training. Additional substantive legislation is also possible in 2008 with the passage by the United States House of Representatives in January 2008 of the Supplementary Mine Improvement and New Emergency Response Act, ("S-MINER Act"). The House legislation augments portions of the MINER Act and proposes changes to retreat mining practices, study of substance abuse issues and the use of coal dust monitors to reduce miner respirable dust exposure.

All of the states in which we operate have state programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry is perhaps the most comprehensive and pervasive system for protection of employee health and safety affecting any segment of industry in the United States. While regulation has a significant effect on our operating costs, our United States competitors are subject to the same degree of regulation.

Our goal is sustainable excellence in our safety and health performance. We are committed to doing our best, and then learning to do even better. We recognize each employee's contributions to our collective safety and health efforts and reward outstanding performance. We measure our success in this area primarily through the use of occupational injury and illness frequency rates. We believe that a superior safety and health regime is inherently tied to achieving productivity and financial goals, with overarching benefits for our shareholders, the community and the environment.

Black Lung. Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to: (i) current and former coal miners totally disabled from black lung disease; and (ii) certain survivors of a miner who dies from black lung disease. The Black Lung Disability Trust Fund, to which we must make certain tax payments based on tonnage sold, provides for the payment of medical expenses to claimants whose last mine employment was before January 1, 1970 and to claimants employed after such date, where no responsible coal mine operator has been identified for claims or where the responsible coal mine operator has defaulted on the payment of such benefits. In addition to federal acts, we are also liable under various state statutes for black lung claims. Federal benefits are offset by any state benefits paid.

Workers' Compensation. We are liable for workers' compensation benefits for traumatic injuries under state workers' compensation laws in which we have operations. Workers' compensation laws are administered by state agencies with each state having its own set of rules and regulations regarding compensation owed to an employee injured in the course of employment.

Coal Industry Retiree Health Benefit Act of 1992 and Tax Relief and Retiree Health Care Act of 2006. The Coal Industry Retiree Health Benefit Act of 1992 ("Coal Act") provides for the funding of health benefits for certain UMWA retirees. The Coal Act established the Combined Benefit Fund ("CBF") into which "signatory operators" and "related persons" are obligated to pay annual premiums for covered beneficiaries. The Coal Act also created a second benefit fund, the 1992 Benefit Plan, for miners who retired between July 21, 1992 and September 30, 1994 and whose former employers are no longer in business. On December 20, 2006, President Bush signed the Tax Relief and Retiree Health Care Act of 2006. This legislation includes important changes to the Coal Act that impacts all companies required to contribute to the CBF. Effective October 1, 2007, the SSA revoked all beneficiary assignments made to companies that did not sign a 1988 UMWA contract ("reachback companies"), but phased-in their premium relief. As a pre-1988 signatory, Massey related reachback companies will receive the applicable premium relief. Effective October 1, 2007, reachback companies will pay only 55% of their plan year 2008 assessed premiums, 40% of their plan year 2009 assessed premiums, and 15% of their plan year 2010 assessed premiums. General United States Treasury money will be transferred to the CBF to make up the difference. After

2010, reachback companies will have no further obligations to the CBF, and transfers from the United States Treasury will cover all of the health care costs for retirees and dependents previously assigned to reachback companies.

Pension Protection Act. The Pension Protection Act of 2006 ("Pension Act") will simplify and transform rules governing the funding of defined benefit plans, accelerate funding obligations of employers, make permanent certain provisions of the Economic Growth and Tax Relief Reconciliation Act of 2001, make permanent the diversification rights and investment education provisions for plan participants and encourage automatic enrollment in defined contribution 401(k) plans. In general, most provisions of the Pension Act will take effect for plan years beginning on or after December 31, 2007. Plans generally will be required to set a funding target of 100% of the present value of accrued benefits and sponsors will be required to amortize unfunded liabilities over a 7-year period. The Pension Act includes a funding target phase-in provision consisting of a 92% funding target in 2008, 94% in 2009, 96% in 2010, and 100% thereafter. Plans with a funded ratio of less than 80%, or less than 70% using special assumptions, will be deemed to be "at risk" and will be subject to additional funding requirements. Our qualified pension plans are currently fully funded.

Environmental Laws

Surface Mining Control and Reclamation Act. The Surface Mining Control and Reclamation Act, ("SMCRA"), which is administered by the Office of Surface Mining Reclamation and Enforcement ("OSM"), establishes mining, environmental protection and reclamation standards for all aspects of surface mining as well as many aspects of deep mining. The SMCRA and similar state statutes require, among other things, the restoration of mined property in accordance with specified standards and an approved reclamation plan. In addition, the Abandoned Mine Land Fund, which is part of the SMCRA, imposes a fee on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is $0.315 per ton on surface-mined coal and $0.135 per ton on deep-mined coal. A mine operator must submit a bond or otherwise secure the performance of its reclamation obligations. Mine operators must receive permits and permit renewals for surface mining operations from the OSM or, where state regulatory agencies have adopted federally approved state programs under the act, the appropriate state regulatory authority. We accrue for reclamation and mine-closing liabilities in accordance with Statement of Financial Accounting Standard ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143") (see Note 9 to the Notes to Consolidated Financial Statements).

Clean Water Act. Section 301 of the Clean Water Act prohibits the discharge of a pollutant from a point source into navigable waters of the United States except in accordance with a permit issued under either Section 402 or Section 404 of the Clean Water Act. Navigable waters are broadly defined to include streams, even those that are not navigable in fact, and may include wetlands. All mining operations in Appalachia generate excess material, which must be placed in fills in adjacent valleys and hollows. Likewise, coal refuse disposal areas and coal processing slurry impoundments are located in valleys and hollows. Almost all of these areas contain intermittent or perennial streams, which are considered navigable waters under the Clean Water Act. An operator must secure a Clean Water Act permit before filling such streams. For approximately the past twenty-five years, operators have secured Section 404 fill permits that authorize the filling of navigable waters with material from various forms of coal mining. Operators have also obtained permits under Section 404 for the construction of slurry impoundments although the use of these impoundments, including discharges from them, requires permits under Section 402. Section 402 discharge permits are generally not suitable for authorizing the construction of fills in navigable waters.

Clean Air Act. Coal contains impurities, including sulfur, mercury, chlorine, nitrogen oxide and other elements or compounds, many of which are released into the air when coal is burned. The Clean Air Act and corresponding state laws extensively regulate emissions into the air of particulate matter and other substances, including sulfur dioxide, nitrogen oxide and mercury. Although these regulations apply directly to impose certain requirements for the permitting and operation of our mining facilities, by far their greatest impact on us and the coal industry generally is the effect of emission limitations on utilities and other customers. Owners of coal-fired power plants and industrial boilers have been required to expend considerable resources in an effort to comply with these air pollution standards. The United States Environmental Protection Agency ("EPA") has imposed or attempted to impose tighter emission restrictions in a number of areas, some of which are currently subject to litigation. The general effect of such tighter restrictions could be to reduce demand for coal. This in turn may result in decreased production and a corresponding decrease in revenue and profits.

National Ambient Air Quality Standards. In 1997, EPA adopted a new National Ambient Air Quality Standard ("NAAQS") for very fine particulate matter and a more stringent NAAQS for ozone. Ozone is produced by a combination of two precursor pollutants: volatile organic compounds and nitrogen oxide, a by-product of coal combustion. States were required to submit to EPA revisions to their State Implementation Plans ("SIPs") that demonstrate the manner in which the states will attain the fine particulate NAAQS by December 18, 2007. The ozone NAAQS has been the subject of litigation and, during the course of this litigation, EPA has proposed revisions to the ozone NAAQS that are more stringent than the standards being litigated. EPA intends to begin the promulgation process for the new, more stringent ozone NAAQS in the Spring of 2008. Revised SIPs could require electric power generators to further reduce nitrogen oxide and sulfur dioxide emissions. In addition to the SIP process, the Clean Air Act permits states to assert claims against sources in other "upwind" states alleging that emission sources including coal fired power plants in the upwind states are preventing the "downwind" states from attaining a NAAQS. All these actions could result in additional controls being required on coal fired power plants and we are unable to predict the effect on coal production.

Acid Rain Control Provisions. The acid rain control provisions promulgated as part of the Clean Air Act Amendments of 1990 in Title IV of the Clean Air Act ("Acid Rain program") required reductions of sulfur dioxide emissions from power plants. The Acid Rain program is now a mature program and we believe that any market impacts of the required controls have likely been factored into the price of coal in the national coal market.

Regional Haze Program. EPA promulgated a regional haze program designed to protect and to improve visibility at and around so-called Class I Areas, which are generally National Parks, National Wilderness Areas and International Parks. This program may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around the Class I Areas. Moreover, the program requires certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxide and particulate matter. States were required to submit Regional Haze SIPs to EPA by December 17, 2007. Many states did not meet the December 17, 2007, deadline and we are unable to predict the impact on the coal market of the failure to submit Regional Haze SIPs by the deadline.

New Source Review Program. Under the Clean Air Act, new and modified sources of air pollution must meet certain new source standards ("New Source Review Program"). In the late 1990s, the EPA filed lawsuits against many coal-fired plants in the eastern United States alleging that the owners performed non-routine maintenance, causing increased emissions that should have triggered the application of these new source standards. Some of these lawsuits have been settled, with the owners agreeing to install additional pollution control devices in their coal-fired plants. The remaining litigation and the uncertainty around the New Source Review Program rules could adversely impact utilities' demand for coal in general or coal with certain specifications, including the coal produced by us.

Multi-Pollutant Strategies. In March 2005, EPA issued two closely related rules designed to significantly reduce levels of sulfur dioxide, nitrogen oxide and mercury: the Clean Air Interstate Rule and the Clean Air Mercury Rule. The Clean Air Interstate Rule sets a cap-and-trade program in 28 states and the District of Columbia to establish emissions limits for sulfur dioxide and nitrogen oxide, by allowing utilities to buy and sell credits to assist in achieving compliance with the NAAQS for 8-hour ozone and fine particulates. The Clean Air Mercury Rule as promulgated will cut mercury emissions nearly 70% by 2018 through a cap-and-trade program. Both rules were challenged in numerous lawsuits. Portions of each of these rules are still in litigation, and on February 8, 2008, the United States Court of Appeals for the District of Columbia Circuit vacated the entire mercury rule and remanded it to EPA for reconsideration. Immediately following the decision, EPA announced that it has not decided how to respond. Regardless of the outcome of litigation on either rule, a form of each of the rules will likely be promulgated and ultimately directly affect coal producers, suppliers and utilities in the eastern and western regions of the United States, by requiring revisions to the SIPs in many eastern states. Any such controls may have an impact on the demand for our coal and possibly give the users of western sub-bituminous coal a significant competitive advantage over eastern bituminous coal users.

Global Climate Change

The United States has not implemented the 1992 Framework Convention on Global Climate Change ("Kyoto Protocol"), which became effective for many countries on February 16, 2005. The Kyoto Protocol was intended to limit or reduce emissions of greenhouse gases, such as carbon dioxide. The United States has not ratified the emission targets of the Kyoto Protocol or any other greenhouse gas agreement among parties.

Nevertheless, global climate change continues to attract considerable public and scientific attention and a considerable amount of legislative attention in the United States is being paid to global climate change and the reduction of greenhouse gas emissions, particularly from coal combustion by power plants. Enactment of laws and passage of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions, could result in electric generators switching from coal to other fuel sources.

Permitting and Compliance

Our operations are principally regulated under surface mining permits issued pursuant to the SMCRA and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. We currently have over 500 surface mining permits. In conjunction with the surface mining permits, most operations hold national pollutant discharge elimination system permits pursuant to the Clean Water Act and state counterpart water pollution control laws for the discharge of pollutants to waters. These permits are issued for terms of five years. Additionally, the Clean Water Act requires permits for operations that fill waters of the United States Valley fills and refuse impoundments are authorized under permits issued under the Clean Water Act by the United States Army Corps of Engineers. Additionally, certain surface mines and preparation plants have permits issued pursuant to the Clean Air Act and state counterpart clean air laws allowing and controlling the discharge of air pollutants. These permits are primarily permits allowing initial construction (not operation) and they do not have expiration dates.

We believe we have obtained all permits required for current operations under the SMCRA, Clean Water Act and Clean Air Act and corresponding state laws. We believe that we are in compliance in all material respects with such permits, and routinely correct violations in a timely fashion in the normal course of operations. The expiration dates of the permits are largely immaterial as the law provides for a right of successive renewal. The cost of obtaining surface mining, clean water and air permits can vary widely depending on the scientific and technical demonstrations that must be made to obtain the permits. However, the cost of obtaining a permit is rarely more than $500,000 and the cost of obtaining a renewal is rarely more than $5,000. It is impossible to predict the full impact of future judicial, legislative or regulatory developments on our operations, because the standards to be met, as well as the technology and length of time available to meet those standards, continue to develop and change.

We believe, based upon present information available to us, that accruals with respect to future environmental costs are adequate. For further discussion on costs, see Note 9 to the Notes to Consolidated Financial Statements. However, the imposition of more stringent requirements under environmental laws or regulations, new developments or changes regarding site cleanup costs or the allocation of such costs among potentially responsible parties, or a determination that we are potentially responsible for the release of hazardous substances at sites other than those currently identified, could result in additional expenditures or the provision of additional accruals in expectation of such expenditures.

Comprehensive Environmental Response, Compensation and Liability Act

The 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. Under the EPA's Toxic Release Inventory process, companies are required annually to report the use, manufacture or processing of listed toxic materials that exceed defined thresholds, including chemicals used in equipment maintenance, reclamation, water treatment and ash received for mine placement from power generation customers. Our current and former coal mining operations incur, and will continue to incur, expenditures associated with the investigation and remediation of facilities and environmental conditions under CERCLA.

Endangered Species Act

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. Based on the species that have been identified on our properties to date and the current application of applicable laws and regulations, 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.

Available Information

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other information with the Securities and Exchange Commission ("SEC"). Our SEC filings are available to the public over the Internet at the SEC's website at www.sec.gov. You may also read and copy any document we file at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. We make available, free of charge through our Internet website, www.masseyenergyco.com, our annual report, quarterly reports, current reports, proxy statements, section 16 reports and other information (and any amendments thereto) as soon as practicable after filing or furnishing the material to the SEC, in addition to, our Corporate Governance Guidelines, codes of ethics and the charters of the Audit, Compensation, Executive, Finance, Governance and Nominating, and Safety, Environmental, and Public Policy Committees. These materials also may be requested at no cost by telephone at (866) 814-6512 or by mail at: Massey Energy Company, Post Office Box 26765, Richmond, Virginia 23261, Attention: Investor Relations.

Executive Officers of the Registrant

Incorporated by reference into this Part I is the information set forth in Part III, Item 10 under the caption "Directors and Executive Officers of the Registrant" (included herein pursuant to Item 401(b) of Regulation S-K).

GLOSSARY OF SELECTED TERMS

Ash. Impurities consisting of iron, aluminum and other incombustible matter that are contained in coal. Since ash increases the weight of coal, it adds to the cost of handling and can affect the burning characteristics of coal.

Bituminous coal. The most common type of coal with moisture content less than 20% by weight and heating value of 10,500 to 14,000 Btu per pound. It is dense and black and often has well-defined bands of bright and dull material.

British thermal unit, or "Btu." A measure of the thermal energy required to raise the temperature of one pound of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

Central Appalachia. Coal producing states and regions of eastern Kentucky, eastern Tennessee, western Virginia and southern West Virginia.

Coal seam. Coal deposits occur in layers. Each layer is called a "seam."

Coke. A hard, dry carbon substance produced by heating coal to a very high temperature in the absence of air. Coke is used in the manufacture of iron and steel. Its production results in a number of useful byproducts.

Compliance coal. Described in Item 1. Business, under the heading "Coal Reserves."

Continuous miner. A mining machine with a continuously rolling cutting cylinder used in underground and highwall mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation.

Direct-ship coal. Coal that is shipped without first being processed.

Deep mine. An underground coal mine.

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 substantial amounts of overburden as it is dragged across the excavation area.

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

Highwall Mining. Described in Item 1. Business, under the heading "Mining Methods."

High vol met coal. Coal that averages approximately 35% volatile matter. Volatile matter refers to the impurities that become gaseous when heated to certain temperatures.

Illinois Basin. The Illinois Basin consists of the coal producing areas in Illinois, Indiana and western Kentucky.

Industrial coal. Coal used by industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Long-term contracts. Contracts with terms of one year or longer.

Longwall mining. Described in Item 1. Business, under the heading "Mining Methods."

Low vol met coal. Coal that averages approximately 20% volatile matter. Volatile matter refers to the impurities that become gaseous when heated to certain temperatures.

Metallurgical coal. The various grades of coal suitable for carbonization to make coke for steel manufacture. Also known as "met" coal, it possesses four important qualities: volatility, which affects coke yield; the level of impurities, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Met coal has a particularly high Btu heat content, but low ash content.

Mine. A mine consists of those operating assets necessary to produce coal from surface or underground locations.

Nitrogen oxide (NOx). Nitrogen oxide is produced as a gaseous by-product of coal combustion.

Northern Appalachia. Northern Appalachia consists of the bituminous coal producing areas in the states of Pennsylvania, Ohio and Maryland and in the northern part of West Virginia.

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

Overburden ratio. The amount of overburden that must be removed to excavate a given quantity of coal. It is commonly expressed in cubic yards per ton of coal or as a ratio comparing the thickness of the overburden with the thickness of the coal bed.

Pillar. An area of coal left to support the overlying strata in an underground mine, sometimes left permanently to support surface structures.

Powder River Basin. The Powder River Basin consists of the coal producing areas in southeast Montana and northeast Wyoming.

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

Probable reserves. Described in Item 1. Business, under the heading "Coal Reserves."

Proven reserves. Described in Item 1. Business, under the heading "Coal Reserves."

Reclamation. The process of restoring land and the environment to their approximate original state following mining activities. The process commonly includes "recontouring" or reshaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers. Reclamation operations are usually underway before the mining of a particular site is completed. Reclamation is closely regulated by both state and federal law.

Reserve. Described in Item 1. Business, under the heading "Coal Reserves."

Resource Group. An organizational unit, generally located within a specific geographic locale, that contains one or more of the following operations related to the mining, processing or shipping of coal: underground mine, surface mine, preparation plant or load-out facility.

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

Room and pillar mining. Described in Item 1. Business, under the heading "Mining Methods."

Scrubber (flue gas desulfurization unit). Any of several forms of chemical/physical devices that operate to neutralize sulfur and other greenhouse gases formed during coal combustion. These devices combine the sulfur in gaseous emissions with other chemicals to form inert compounds, such as gypsum, that must then be removed for disposal. Although effective in substantially reducing sulfur from combustion gases, scrubbers require about 6% to 7% of a power plant's electrical output and thousands of gallons of water to operate.

Steam coal. Coal used by power plants and industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal. Also known as utility coal.

Stoker coal. Coal that is sized to a specific, standard range. Stoker coal is typically one quarter inch by one and one quarter to one and three quarter inch.

Sulfur. One of the elements present in varying quantities in coal that reacts with air when coal is burned to form sulfur dioxide.

Sulfur content. Coal is commonly described by its sulfur content due to the importance of sulfur in environmental regulations. "Low sulfur" coal has a variety of definitions, but typically is used to describe coal consisting of 1.0% or less sulfur. A majority of our Appalachian reserves are of low sulfur grades.

Sulfur dioxide (SO_2). Sulfur dioxide is produced as a gaseous by-product of coal combustion.

Surface mining. Described in Item 1. Business, under the heading "Mining Methods."

Tons. A "short" or net ton is equal to 2,000 pounds. A "long" or British ton is approximately 2,240 pounds; a "metric" tonne is approximately 2,205 pounds. The short ton is the unit of measure referred to in this Annual Report on Form 10-K.

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.

Unit train. A railroad train of a specified number of railroad cars carrying only coal. A typical unit train can carry at least 10,000 tons of coal in a single shipment.

Utility coal. Coal used by power plants to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal. Also known as steam coal.

Item 1A. Risk Factors

We are subject to a variety of risks, including, but not limited to, those risk factors set forth below and those referenced herein to other Items contained in this Annual Report on Form 10-K, including Item 1. Business, under the headings "Customers and Coal Contracts," "Competition," "Environmental, Safety and Health Laws and Regulations," Item 3. Legal Proceedings and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A"), under the headings "Critical Accounting Estimates and Assumptions," "Certain Trends and Uncertainties" and elsewhere in MD&A.

We are impacted by the competitiveness of the markets in which we compete and market demand for coal.

We compete with coal producers in various regions of the United States and overseas for domestic and international sales. Continued domestic demand for our coal and the prices that we will be able to obtain primarily will depend upon coal consumption patterns of the domestic electric utility industry and the domestic steel industry. Consumption by the domestic utility industry is affected by the demand for electricity, environmental and other governmental regulations, technological developments and the price of competing coal and alternative fuel supplies including nuclear, natural gas, oil and renewable energy sources, including hydroelectric power. Consumption by the domestic steel industry is primarily affected by economic growth and the demand for steel used in construction as well as appliances and automobiles. In recent years, the competitive environment for coal has been impacted by sustained growth in a number of the largest markets in the world, including the United States, China, Japan and India, where demand for both electricity and steel have supported pricing for steam and metallurgical coal. The cost of ocean transportation and the valuation of the United States dollar in relation to foreign currencies significantly impact the relative attractiveness of our coal as we compete on price with other foreign coal producing sources. See Item 1. Business, under the heading "Competition," for further discussion.

Portions of our coal reserves possess quality characteristics that enable us to mine, process and market them as either metallurgical coal or high quality steam coal, depending on the prevailing conditions in the metallurgical and steam coal industries. A decline in the metallurgical market relative to the steam market could cause us to shift coal from the metallurgical market to the steam market. If demand for metallurgical coal declined to the point where we could earn a more attractive return marketing the coal as steam coal, there could be a material impact on cash flows, results of operations or financial condition.

Demand for our coal depends on its price and quality and the cost of transporting it to customers.

Coal prices are influenced by a number of factors and may vary dramatically by region. The two principal components of the price of coal are the price of coal at the mine, which is influenced by mine operating costs and coal quality, and the cost of transporting coal from the mine to the point of use. The cost of mining the coal is influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. Underground mining is generally more expensive than surface mining as a result of higher costs for labor (including reserves for future costs associated with labor benefits and health care) and capital costs (including costs for mining equipment and construction of extensive ventilation systems). As of January 31, 2008, we operated 35 active underground mines, including two longwall mines, and 12 active surface mines, with 8 highwall miners. See Item 1. Business, under the headings "Mining Methods," "Mining Operations" and "Competition" for further discussion.

Transportation costs represent a significant portion of the delivered cost of coal and, as a result, the cost of delivery is a critical factor in a customer's purchasing decision. Increases in transportation costs could make coal a less competitive source of energy. Such increases could have a material impact on our ability to compete with other energy sources and on our cash flows, results of operations or financial condition. Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country or the world, including coal imported into the United States (several United States ports have announced plans to increase their capacity to import coal). For instance, coal mines in the western United States could become an increasingly attractive source of coal to consumers in the eastern part of the country if the costs of transporting coal from the west were significantly reduced and rail capacity was increased. See Item 1. Business, under the heading "Competition," for further discussion.

A significant decline in coal prices in general could adversely affect our operating results and cash flows.

Our results are highly dependent upon the prices we receive for our coal. Decreased demand for coal, both domestically and internationally, could cause spot prices and the prices we are able to negotiate on long-term contracts to decline. The lower prices could negatively affect our cash flows, results of operations or financial condition, if we are unable to increase productivity and/or decrease costs in order to maintain our margins.

We depend on continued demand from our customers.

Reduced demand from or the loss of our largest customers could have an adverse impact on our ability to achieve projected revenue. Decreases in demand may result from, among other things, a reduction in consumption by the electric generation industry and/or the steel industry, the availability of other sources of fuel at cheaper costs and a general slowdown in the economy. When our contracts with customers reach expiration, there can be no assurance that the customers either will extend or enter into new long-term contracts or, in the absence of long-term contracts, that they will continue to purchase the same amount of coal as they have in the past or on terms, including pricing terms, as favorable as under existing arrangements. In the event that a large customer account is lost or a long-term contract is not renewed, profits could suffer if alternative buyers are not willing to purchase our coal on comparable terms.

There may be adverse changes in price, volume or terms of our existing coal supply agreements.

Many of our coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. These contracts may be adjusted based on inflation or deflation and/or changes in the factors affecting the cost of producing coal, such as taxes, fees, royalties and changes in the laws regulating the mining, production, sale or use of coal. In a limited number of contracts, failure of the parties to agree on a price under those provisions may allow either party to terminate the contract. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or the customer during the duration of specified events beyond the control of the affected party. Most coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as Btu, sulfur content, ash content, grindability and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or termination of the contracts. See Item 1. Business, under the heading "Customers and Coal Contracts" for further discussion.

Our financial condition may be adversely affected if we are required by some of our customers to provide performance assurances for certain below-market sales contracts.

Contracts covering a significant portion of our contracted sales tons contain provisions that could require us to provide performance assurances if we experience a material adverse change or, under certain other contracts, if the customer believes our creditworthiness has become unsatisfactory. Generally, under such contracts, performance assurances are only required if the contract price per ton of coal is below the current market price of the coal. Certain of the contracts limit the amount of performance assurance to a per ton amount in excess of the contract price, while others have no limit. The performance assurances are generally provided by the posting of a letter of credit, cash collateral, other security, or a guaranty from a creditworthy guarantor. As of February 28, 2008, we have not received any requests from any of our customers to provide performance assurances. If we are required to post performance assurances on some or all of our contracts with performance assurances provisions, there could be a material impact on our cash flows, results of operations or financial condition.

The level of our indebtedness could adversely affect our ability to grow and compete and prevent us from fulfilling our obligations under our contracts and agreements.

At December 31, 2007, we had $1,104.5 million of total indebtedness outstanding, which represented 58.5% of our total book capitalization. We have significant debt, lease and royalty obligations. Our ability to satisfy debt service, lease and royalty obligations and to effect any refinancing of 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.

Our relative amount of debt 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 payments 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 the business and the industry in which we compete; or (vii) placing us at a competitive disadvantage with competitors with relatively lower amounts of debt.

The covenants in our credit facility and the indentures governing debt instruments impose restrictions that may limit our operating and financial flexibility.

Our asset based loan credit facility and the indentures governing our notes contain a number of significant restrictions and covenants that may limit our ability and our subsidiaries' ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create lien or security interests in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) restrict distributions from subsidiaries.

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

We depend on our ability to continue acquiring and developing economically recoverable coal reserves.

A key component of our future success is our ability to continue acquiring coal reserves for development that have the geological characteristics that allow them to be economically mined. Replacement reserves may not be available or, if available, may not be capable of being mined at costs comparable to those characteristics of the depleting mines. An inability to continue acquiring economically recoverable coal reserves could have a material impact on our cash flows, results of operations or financial condition.

We face numerous uncertainties in estimating economically recoverable coal reserves, and inaccuracies in estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by us. Some of the factors and assumptions that impact economically recoverable reserve estimates include: (i) geological conditions; (ii) historical production from the area compared with production from other producing areas; (iii) the effects of regulations and taxes by governmental agencies; (iv) future prices; and (v) future operating costs.

Each of these factors may vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal attributable to a particular group of properties may vary substantially. As a result, our estimates may not accurately reflect our actual reserves. Actual production, revenues and expenditures with respect to reserves will likely vary from estimates, and these variances may be material.

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

A significant portion of our mining operations occurs on properties that we lease. Title defects or the loss of leases could adversely affect our ability to mine the reserves covered by those leases. Our current practice is to obtain a title review from a licensed attorney prior to leasing property. We generally have not obtained title insurance in connection with acquisitions of coal reserves. In some cases, the seller or lessor warrants property title. Separate title confirmation sometimes is not required when leasing reserves where mining has occurred previously. Our right to mine some of our reserves may be adversely affected if defects in title or boundaries exist. In order to obtain leases to conduct our mining operations on property where these defects exist, we may have to incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease.

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

An increase in the demand for coal could attract new investors to the coal industry, which could spur the development of new mines, and result in added production capacity throughout the industry. We have announced plans to increase our coal production by approximately 20% over the next three years. Several of our competitors have also announced plans for increases in production capacity over the next several years. Higher price levels of coal could further encourage the development of expanded capacity by new or existing coal producers. Any resulting increases in capacity could further reduce coal prices and reduce our margins. See Item 1. Business, under the heading "Competition," for further discussion.

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

We sometimes obtain coal from brokerage sources and contract miners to fulfill deliveries under our coal supply agreements. Some of our brokerage sources may experience adverse geologic mining, escalated operating costs and/or financial difficulties that make their delivery of coal to us at the contracted price difficult or uncertain. Our profitability or exposure to loss on transactions or relationships such as these is dependent upon the reliability of the supply, the ability to substitute, when economical, third-party coal sources with internal production or coal purchased in the market and other factors.

Decreased availability or increased costs of key equipment, supplies or commodities such as diesel fuel, steel, explosives and tires could decrease our profitability.

Our operations are dependant on reliable supplies of mining equipment, replacement parts, explosives, diesel fuel, tires, and steel-related products (including roof bolts). If the cost of any mining equipment or key supplies increases significantly, or if they should become unavailable due to higher industry-wide demand or less production by suppliers, there could be an adverse impact on our cash flows, results of operations or financial condition. In recent years, mining industry demand growth has exceeded supply growth for certain surface and underground mining equipment and heavy equipment tires.

Transportation disruptions could impair our ability to sell coal.

We are dependent on our transportation providers to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lockouts or other events could temporarily impair our ability to supply coal to customers. Our ability to ship coal could be negatively impacted by a reduction in available and timely rail service. Lack of sufficient resources to meet a rapid increase in demand, a greater demand for transportation to export terminals and rail line congestion all could contribute to a disruption and slowdown in rail service.

Severe weather may affect our ability to mine and deliver coal.

Severe weather, including flooding and excessive ice or snowfall, when it occurs, can adversely affect our ability to produce, load and transport coal, which may negatively impact our cash flows, results of operations or financial condition.

Federal and state government regulations applicable to operations increase costs and may make our coal less competitive than other coal producers.

We incur substantial costs and liabilities under increasingly strict federal, state and local environmental, health and safety and endangered species laws, regulations and enforcement policies. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. We may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. See Item 1. Business, under the heading "Environmental, Safety and Health Laws and Regulations" for further discussion of this risk.

New legislation and new regulations may be adopted which could materially adversely affect our mining operations, cost structure or our customers' ability to use coal. New legislation and new regulations may also require us, as well as our customers, to change operations significantly or incur increased costs. The EPA has undertaken broad initiatives aimed at increasing compliance with emissions standards and to provide incentives to our customers for decreasing emissions, often by switching to an alternative fuel source or by installing scrubbers at their coal-fired plants.

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

The Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. Such regulations may require significant emissions control expenditures for many coal-fired power plants to comply with applicable ambient air quality standards. As a result, the generators may switch to other fuels that generate less of these emissions or install more effective pollution control equipment, possibly reducing future demand for coal and the construction of coal-fired power plants. The majority of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser's plant or results in specified increases in the cost of coal or its use.

Global climate change continues to attract considerable public and scientific attention. Widely publicized scientific reports in 2007, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. A considerable amount of legislative attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants. According to EIA, "Emissions of Greenhouse Gases in the United States 2006," coal accounts for 30% of greenhouse gas emissions in the United States. Legislation was introduced in Congress in 2006 and 2007 to reduce greenhouse gas emissions in the United States and additional legislation has been proposed and is likely to be introduced in the future. In addition, a growing number of states in the United States are taking steps to reduce greenhouse gas emissions from coal-fired power plants. The United States Supreme Court's recent decision in Massachusetts v. Environmental Protection Agency ruled that the EPA improperly declined to address carbon dioxide impacts on climate change in a recent rulemaking. Although the specific rulemaking related to new motor vehicles, the reasoning of the decision could affect other federal regulatory programs, including those that directly relate to coal use. Enactment of laws and passage of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions, could result in electric generators switching from coal to other fuel sources.

Further developments in connection with legislation, regulations or other limits on greenhouse gas emissions and other environmental impacts from coal combustion, both in the United States and in other countries where we sell coal, could have a material adverse effect on our cash flows, results of operations or financial condition. See Item 1. Business, under the heading "Environmental, Safety and Health Laws and Regulations" for further discussion of this risk.

MSHA or other federal or state regulatory agencies may order certain of our mines to be temporarily or permanently closed, which could adversely affect our ability to meet our customers' demands.

MSHA or other federal or state regulatory agencies may order certain of our mines to be temporarily or permanently closed. Our customers may challenge our issuance of force majeure notices in connection with such closures. If these challenges are successful, we may have to purchase coal from third party sources to satisfy those challenges, negotiate settlements with customers, which may include price reductions, the reduction of commitments or the extension of the time for delivery, terminate customers' contracts or face claims initiated by our customers against us. The resolution of these challenges could have an adverse impact on our cash flows, results of operations or financial condition.

We must obtain governmental permits and approvals for mining operations, which can be a costly and time-consuming process and can result in restrictions on our operations.

Our operations are principally regulated under surface mining permits issued pursuant to the SMCRA and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. Additionally, the Clean Water Act requires permits for operations that fill waters of the United States. Valley fills and refuse impoundments are typically authorized under nationwide permits that are revised and renewed periodically by the United States Army Corps of Engineers. Additionally, certain surface mines and preparation plants have permits issued pursuant to the Clean Air Act and state counterpart clean air laws allowing and controlling the discharge of air pollutants. Regulatory authorities exercise considerable discretion in the timing of permit issuance. Requirements imposed by these authorities may be costly and time-consuming and may result in delays in the commencement or continuation of development or production operations. See Item 1. Business, under the heading "Environmental, Safety and Health Laws and Regulations" for further discussion.

The loss of key personnel or the failure to attract qualified personnel could affect our ability to operate our company effectively.

The successful management of our business is dependent on a number of key personnel. Our future success will be affected by our continued ability to attract and retain highly skilled and qualified personnel. There are no assurances that key personnel will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have an adverse affect on our cash flows, results of operations or financial condition.

Union represented labor creates an increased risk of work stoppages and higher labor costs.

At December 31, 2007, 2.0% of our total workforce was represented by the UMWA. During 2007, six of our coal preparation plants and one smaller surface mine had a workforce represented by the UMWA. In 2007, these preparation plants handled approximately 28% of our coal production. There may be an increased risk of strikes and other related work actions, in addition to higher labor costs, associated with these operations. If some or all of our current open shop operations were to become union represented, we could be subject to additional risk of work stoppages and higher labor costs, which could adversely affect the stability of production and reduce net income.

We are subject to being adversely affected by a decline in the financial condition and creditworthiness of our customers.

In an effort to mitigate credit-related risks in all customer classifications, we maintain a credit policy, which requires scheduled reviews of customer creditworthiness and continuous monitoring of customer news events that might have an impact on their financial condition. Negative credit performance or events may trigger the application of tighter terms of sale, requirements for collateral or, ultimately, a suspension of credit privileges. The creditworthiness of customers can limit who we can do business with and at what price. For the year ended December 31, 2007, approximately 95% of coal sales volume was pursuant to long-term contracts. We anticipate that in 2008, the percentage of our sales pursuant to long-term contracts will be comparable with the percentage of our sales for 2007 and almost 60% of our projected 2008 sales is contracted to be sold to our 10 largest customers. If one or more of our largest customers experiences financial difficulties and fails to make payment for our sales to them, there could be an adverse effect on our cash flows, results of operations or financial condition.

We have contracts to supply coal to energy trading and brokering companies who resell the coal to the ultimate users. We are subject to being adversely affected by any decline in the financial condition and creditworthiness of these energy trading and brokering companies. In addition, as the largest supplier of metallurgical coal to the American steel industry, we are subject to being adversely affected by any decline in the financial condition or production volume of American steel producers. See Item 1. Business, under the heading "Customers and Coal Contracts" for further discussion.

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

We are parties to a number of legal proceedings incident to normal business activities. Some of the allegations brought against us are with merit, while others are not. There is always the potential that an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position. See Item 3. Legal Proceedings and Note 17 to the Notes to Consolidated Financial Statements for further discussion.

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

The SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Estimates of our total reclamation and mine-closing liabilities are based upon permit requirements and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by management and engineers. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. See Item 1. Business, under the heading "Environmental, Safety and Health Laws and Regulations" for further discussion.

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

We are subject to long-term liabilities under a variety of benefit plans and other arrangements with current and former employees. These obligations have been estimated based on actuarial assumptions, including actuarial estimates, assumed discount rates, estimates of life expectancy, expected returns on pension plan assets and changes in healthcare costs.

If our assumptions relating to these benefits change in the future or are incorrect, we may be required to record additional expenses, which would reduce our profitability. In addition, future regulatory and accounting changes relating to these benefits could result in increased obligations or additional costs, which could also have a material impact on our cash flows, results of operations or financial condition. For a further discussion, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations under the heading "Critical Accounting Estimates and Assumptions" and Notes 5 and 10 to the Notes to Consolidated Financial Statements.

We may not realize all or any of the anticipated benefits from acquisitions we undertake, as acquisitions entail a number of inherent risks.

From time to time we expand our business and reserve position through acquisitions of businesses and assets, mergers, joint ventures or other transactions. Such transactions involve various inherent risks, such as:

- uncertainties in assessing the value, strengths and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental liabilities) of, acquisition or other transaction candidates;
- the potential loss of key customers, management and employees of an acquired business;
- the ability to achieve identified operating and financial synergies anticipated to result from an acquisition or other transaction;
- problems that could arise from the integration of the acquired business; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying the acquisition or other transaction rationale.

Any one or more of these and other factors could cause us not to realize the benefits anticipated to result from the acquisition of businesses or assets or could result in unexpected liabilities associated with these acquisitions.

Foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We rely on customers in other countries for a portion of our sales, with shipments to countries in North America, South America, Europe, Asia and Africa. We compete in these international markets against coal produced in other countries. Coal is sold internationally in United States dollars. As a result, mining costs in competing producing countries may be reduced in United States dollar terms based on currency exchange rates, providing an advantage to foreign coal producers. Currency fluctuations among countries purchasing and selling coal could adversely affect the competitiveness of our coal in international markets.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our cash flows, results of operations or financial condition.

Our business is affected by general economic conditions, fluctuations in consumer confidence and spending, and market liquidity, which can decline as a result of numerous factors outside of our control, such as terrorist attacks and acts of war. Future terrorist attacks against United States targets, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions affecting customers may materially adversely affect operations. As a result, there could be delays or losses in transportation and deliveries of coal to customers, decreased sales of coal and extension of time for payment of accounts receivable from customers. Strategic targets such as energy-related assets may be at greater risk of future terrorist attacks than other targets in the United States. In addition, such disruption may lead to significant increases in energy prices that could result in government-imposed price controls. It is possible that any, or a combination, of these occurrences could have a material impact on cash flows, results of operations or financial condition.

Coal mining is subject to inherent risks, some of which we insure against and some of which we self-insure.

Our operations are subject to certain events and conditions that could disrupt operations, including fires and explosions, accidental minewater discharges, natural disasters, equipment failures, maintenance problems and flooding. We maintain insurance policies that provide limited coverage for some, but not all, of these risks. Even where insurance coverage applies, there can be no assurance that these risks would be fully covered by insurance policies. We self-insure our highwall miners and underground equipment, including our longwalls. We do not currently carry business interruption insurance.

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

The mining industry has limited industry specific accounting literature and, as a result, we understand diversity in practice exists in the interpretation and application of accounting literature to mining specific issues. As diversity in mining industry accounting is addressed, we may need to restate our reported results if the resulting interpretations differ from our current accounting practices (for additional information regarding our accounting policies, please see Results of Operations — Critical Accounting Estimates and Assumptions and Note 1 to the Notes to Consolidated Financial Statements).

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We own and lease properties totaling more than 988,000 acres in West Virginia, Kentucky, Virginia, Pennsylvania and Tennessee. In addition, certain of our owned or leased properties are leased or subleased to third party tenants. Our current practice is to obtain a title review from a licensed attorney prior to purchasing or leasing property. We generally have not obtained title insurance in connection with acquisitions of coal reserves. In some cases, the seller or lessor warrants property title. We have not required title confirmation in certain cases under long-standing lease agreements where we are now the current lessor and the lease covers property where mining has occurred previously. We currently own or lease the equipment that is utilized in mining operations. The following table describes the location and general character of our major existing facilities, exclusive of mines, coal preparation plants and their adjoining offices.

Administrative Offices:

Richmond, Virginia	Owned	Massey Corporate Headquarters
Charleston, West Virginia	Leased	Massey Coal Services Office
Chapmanville, West Virginia	Leased	Massey Coal Services Field Office

In 2008, we plan to complete construction of our new Massey Coal Services office building, located in Boone County, West Virginia. The building will combine the Charleston and Chapmanville offices.

For a description of mining properties, see Item 1. Business, under the heading "Mining Operations" and "Coal Reserves."

Item 3. Legal Proceedings

Martin County Impoundment Discharge

On October 11, 2000, a partial failure of the coal refuse impoundment of Martin County Coal Corporation, one of our subsidiaries, released approximately 250 million gallons of coal slurry into two tributary streams of the Big Sandy River in eastern Kentucky. On May 30, 2006, the Federal Mine Safety and Health Review Commission remanded citations and penalties issued by MSHA initially totaling approximately $110,000, subsequently reduced to $5,500 by an administrative law judge ("ALJ"), to a new ALJ for further consideration. On November 13, 2007, the new ALJ dismissed the citations and penalties entirely. We do not intend to report on this matter in the future, absent unexpected material developments.

Shareholder Suits

On July 2, 2007, Manville Personal Injury Trust ("Manville") filed a suit in the Circuit Court of Kanawha County, West Virginia, which suit was amended on December 14, 2007, styled as a shareholder derivative action asserting that it is a shareholder acting on our behalf. We are named as a nominal defendant. Each of the members of our Board of Directors, certain of our officers, and certain of our former directors and officers are named as defendants ("Manville Defendants"). The Manville Defendants filed motions to dismiss the complaint with the Circuit Court, which Manville has opposed.

On September 7, 2007, Vernon Mercier filed a similar action in the United States District Court, Southern District of West Virginia, styled as a shareholder derivative action asserting that he is a shareholder acting on our behalf. We are named as a nominal defendant. Each of the members of our Board of Directors and certain of our officers and one former officer are named as defendants ("Vernon Mercier Defendants"). On January 25, 2008, the Vernon Mercier Defendants filed motions to dismiss the action with the United States District Court, and alternatively to stay the action pending resolution of the Manville case.

Each of these complaints alleges breach of fiduciary duties to us arising out of either the Manville Defendants' or the Vernon Mercier Defendants' alleged failure to cause us to comply with applicable state and federal environmental and worker-safety laws and regulations. Both of the complaints seek to recover unspecified damages in favor of us, appropriate equitable relief, and an award to Manville and Vernon Mercier, respectively, of the costs and expenses associated with these actions.

We believe we, the Manville Defendants and the Vernon Mercier Defendants have insurance coverage applicable to these matters. We believe these matters will be resolved without a material impact on our cash flows, results of operations or financial condition.

Other Legal Proceedings

Certain information regarding other legal proceedings required by this Item 3 is contained in Note 17, "Contingencies and Commitments," to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K and is incorporated herein by reference.

We are parties to a number of other legal proceedings, incident to our normal business activities. These matters include, but are not limited to, contract disputes, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates, we do not believe that any liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition. However, it is reasonably possible that the ultimate liabilities in the future with respect to these lawsuits and claims may be material to our cash flows, results of operations or financial condition.

We are also party to lawsuits and other legal proceedings related to the non-coal businesses previously conducted by Fluor Corporation (renamed Massey Energy Company) but now conducted by New Fluor. Under the terms of the Distribution Agreement entered into by New Fluor and us as of November 30, 2000, in connection with the Spin-Off of New Fluor, New Fluor agreed to indemnify us with respect to all such legal proceedings and has assumed their defense.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders through a solicitation of proxies or otherwise during the fourth quarter of the fiscal year ended December 31, 2007.

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock

Common Stock is listed on the New York Stock Exchange ("NYSE") and trades under the symbol MEE. As of February 15, 2008, there were 80,491,644 shares outstanding and approximately 6,833 shareholders of record of Common Stock.

The following table sets forth the high and low sales prices per share of Common Stock on the NYSE for the past two years, based upon published financial sources, and the dividends declared on each share of Common Stock for the quarter indicated.

	High	Low	Dividends
Fiscal Year 2006			
Quarter ended March 31, 2006	$ 41.53	$ 33.10	$ 0.04
Quarter ended June 30, 2006	$ 44.34	$ 32.15	$ 0.04
Quarter ended September 30, 2006	$ 37.05	$ 18.77	$ 0.04
Quarter ended December 31, 2006	$ 28.00	$ 19.31	$ 0.04
Fiscal Year 2007			
Quarter ended March 31, 2007	$ 26.35	$ 21.55	$ 0.04
Quarter ended June 30, 2007	$ 30.73	$ 23.97	$ 0.04
Quarter ended September 30, 2007	$ 26.80	$ 16.01	$ 0.04
Quarter ended December 31, 2007	$ 37.99	$ 21.49	$ 0.05

Dividends

On February 19, 2008, our board of directors declared a dividend of $0.05 per share, payable on April 8, 2008, to shareholders of record on March 25, 2008.

Our current dividend policy anticipates the payment of quarterly dividends in the future. Our asset-based revolving credit facility (the "ABL Facility"), our 6.625% senior notes due 2010 (the "6.625% Notes") and our 6.875% senior notes due 2013 (the "6.875% Notes") contain provisions that restrict us from paying dividends in excess of certain amounts. The ABL Facility limits the payment of dividends to $50 million annually on Common Stock. The 6.625% Notes and the 6.875% Notes limit the payment of dividends to $25 million annually on Common Stock, plus the availability in the Restricted Payments Baskets (as defined in the Indentures to the 6.625% Notes and 6.875% Notes). In addition, dividends can be paid only so long as no default exists under the ABL Facility, the 6.625% Notes, or the 6.875% Notes, as the case may be, or would result thereunder from paying such dividend. There are no other restrictions, other than those set forth under the corporate laws of the State of Delaware, where we are incorporated, on our ability to declare and pay dividends. The declaration and payment of dividends to holders of Common Stock will be at the discretion of the Board of Directors and will be dependent upon our future earnings, financial condition, and capital requirements.

Convertible Debt Securities

Our 4.75% convertible senior notes due 2023 (the "4.75% Notes") are convertible by holders into shares of Common Stock during certain periods under certain circumstances. As of December 31, 2007, the price of Common Stock had reached the specified threshold for conversion. Consequently, the 4.75% Notes are convertible until March 31, 2008, the last day of our first quarter. The 4.75% Notes may be convertible beyond this date if the specified threshold for conversion is met in subsequent quarters. No conversions occurred during 2007. If all of the notes outstanding at December 31, 2007 had been converted, we would have been required to issue 37,649 shares of Common Stock. In addition, holders of the 4.75% Notes may require us to purchase all or a portion of their 4.75% Notes on May 15, 2009, May 15, 2013, and May 15, 2018. For purchases on May 15, 2013 or May 15, 2018, we may, at our option, choose to pay the purchase price in cash or in shares of Common Stock or any combination thereof. See Note 6 to the Notes to Consolidated Financial Statements for further discussion of the conversion and redemption features of the 4.75% Notes.

Our 2.25% convertible senior notes due 2024 (the "2.25% Notes") are convertible by holders into shares of Common Stock during certain periods under certain circumstances. None of the 2.25% Notes were eligible for conversion at December 31, 2007. If all of the notes outstanding at December 31, 2007 had been eligible and were converted, we would have been required to issue 287,113 shares of Common Stock. See Note 6 to the Notes to Consolidated Financial Statements for further discussion of conversion features of the 2.25% Notes.

Repurchase Program

On November 14, 2005, our Board of Directors authorized a stock repurchase program (the "Repurchase Program"), authorizing us to repurchase shares of Common Stock. We may repurchase Common Stock from time to time, as determined by authorized officers, up to an aggregate amount not to exceed $500 million (excluding commissions) with free cash flow as existing financing covenants may permit. Existing covenants currently allow for up to approximately $27.5 million of share repurchases. The stock repurchases may be conducted on the open market, through privately negotiated transactions, through derivative transactions or through purchases made in accordance with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended ("Exchange Act"), in compliance with the SEC's regulations and other legal requirements. The Repurchase Program does not require us to acquire any specific number of shares and may be terminated at any time. On April 24, 2006, our Board of Directors amended the program to allow share repurchases of up to $50 million using cash currently on hand. Share repurchases of $50 million using cash on hand were completed on June 8, 2006, with the purchase of 1,299,000 shares of Common Stock at an average price of $38.47 per share. In August 2007, 1,575,800 shares of Common Stock were purchased at an average price of $19.01 per share. No additional share repurchases have been made since that time. All shares repurchased under the program have been recorded as Treasury stock.

Transfer Agent and Registrar

The transfer agent and registrar for Common Stock is Wells Fargo Shareowner Services, 161 North Concord Exchange, South St. Paul, Minnesota 55075, toll free (800) 689-8788.

Item 6. Selected Financial Data

SELECTED FINANCIAL DATA[1]

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(In millions, except per share, per ton, and number of employees amounts)				
CONSOLIDATED STATEMENT OF INCOME DATA:					
Produced coal revenue	$ 2,054.4	$ 1,902.3	$ 1,777.7	$ 1,456.7	$ 1,262.1
Total revenue	2,413.5	2,219.9	2,204.3	1,766.6	1,571.4
Income (Loss) before interest and income taxes	179.7	111.0	(20.9)	46.2	(17.5)
Income (Loss) before cumulative effect of accounting change	94.1	41.6	(101.6)	13.9	(32.3)
Net income (loss)	94.1	41.0	(101.6)	13.9	(40.2)
Income (Loss) per share - Basic [1]					
Income (Loss) before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)	$ 0.18	$ (0.43)
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)	$ 0.18	$ (0.54)
Income (Loss) per share - Diluted [1]					
Income (Loss) before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)	$ 0.18	$ (0.43)
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)	$ 0.18	$ (0.54)
Dividends declared per share	$ 0.17	$ 0.16	$ 0.16	$ 0.16	$ 0.16
CONSOLIDATED BALANCE SHEET DATA:					
Working capital	$ 522.6	$ 445.2	$ 670.8	$ 458.4	$ 443.2
Total assets	2,860.7	2,740.7	2,986.5	2,650.9	2,376.7
Long-term debt	1,102.7	1,102.3	1,102.6	900.2	784.3
Shareholders' equity [2]	784.0	697.3	841.0	776.9	759.0
OTHER DATA:					
EBIT [3]	$ 179.7	$ 111.0	$ (20.9)	$ 46.2	$ (17.5)
EBITDA [3]	$ 425.7	$ 341.5	$ 213.6	$ 270.8	$ 179.0
Average cash cost per ton sold [4]	$ 43.10	$ 42.33	$ 35.62	$ 30.50	$ 28.23
Produced coal revenue per ton sold	$ 51.55	$ 48.71	$ 42.02	$ 36.02	$ 30.79
Capital expenditures	$ 270.5	$ 298.1	$ 346.6	$ 347.2	$ 164.4
Produced tons sold	39.9	39.1	42.3	40.4	41.0
Tons produced	39.5	38.6	43.1	42.0	41.0
Number of employees	5,407	5,517	5,709	5,034	4,428

(1) In accordance with accounting principles generally accepted in the United States ("GAAP"), the effect of certain dilutive securities was excluded from the calculation of the diluted income (loss) per common share for the years ended December 31, 2007, 2006, 2005, 2004, and 2003, as such inclusion would result in antidilution.

(2) Certain accounting pronouncements adopted in 2007 and 2006 affect the comparability of the 2007 and 2006 financial statements to prior years. The adoption of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" on January 1, 2007 increased equity by $5.2 million (see Note 7 to the Notes to Consolidated Financial Statements for more information). The adoption of Emerging Issues Task Force Issue No. 04-6, "Accounting for Stripping Costs Incurred During Production in the Mining Industry" on January 1, 2006 decreased equity by $93.8 million and the adoption of SFAS No. 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" on December 31, 2006 decreased equity by $40.2 million (see Notes 5, 10 and 11 to the Notes to Consolidated Financial Statements for more information).

(3) EBIT is defined as Income (Loss) before interest and taxes. EBITDA is defined as Income (Loss) before interest and taxes before deducting Depreciation, depletion, and amortization ("DD&A"). Although neither EBIT nor EBITDA are measures of performance calculated in accordance with GAAP, we believe that both measures are useful to an investor in evaluating us because they are widely used in the coal industry as measures to evaluate a company's operating performance before debt expense and as a measure of its cash flow. Neither EBIT nor EBITDA purport to represent operating income, net income or cash generated by operating activities and should not be considered in isolation or as a substitute for measures of performance calculated in accordance with GAAP. In addition, because neither EBIT nor EBITDA are calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. The table below reconciles the GAAP measure of Net income to EBIT and to EBITDA. For the year ended December 31, 2005, EBIT and EBITDA include charges related to our capital restructuring of $212.4 million.

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(In millions)				
Net income (loss)	$ 94.1	$ 41.0	$(101.6)	$ 13.9	$ (40.2)
Cumulative effect of accounting change, net of tax	-	0.6	-	-	7.9
Income tax expense(benefit)	35.4	3.4	26.2	(19.5)	(28.3)
Net interest expense	50.2	66.0	54.5	51.8	43.1
EBIT	179.7	111.0	(20.9)	46.2	(17.5)
Depreciation, depletion and amortization	246.0	230.5	234.5	224.6	196.5
EBITDA	$ 425.7	$ 341.5	$ 213.6	$ 270.8	$ 179.0

(4) Average cash cost per ton is calculated as the sum of Cost of produced coal revenue and Selling, general and administrative expense ("SG&A") (excluding DD&A), divided by the number of produced tons sold. Although Average cash cost per ton is not a measure of performance calculated in accordance with GAAP, we believe that it is useful to investors in evaluating us because it is widely used in the coal industry as a measure to evaluate a company's control over its cash costs. Average cash cost per ton should not be considered in isolation or as a substitute for measures of performance in accordance with GAAP. In addition, because Average cash cost per ton is not calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. The table below reconciles the GAAP measure of Total costs and expenses to Average cash cost per ton.

	Year Ended December 31,									
	2007		2006		2005		2004		2003	
	(In millions, except per ton amounts)									
	$	per ton	$	per ton	$	per ton	$	per ton	$	per ton
Total costs and expenses	$ 2,233.8		$ 2,108.8		$ 2,225.2		$ 1,720.4		$ 1,588.9	
Less: Freight and handling costs	167.6		156.5		150.9		148.8		109.7	
Less: Cost of purchased coal revenue	95.2		62.6		112.6		104.1		117.3	
Less: Depreciation, depletion and amortization	246.0		230.5		234.5		224.6		196.5	
Less: Other expense	7.3		6.2		8.0		9.5		9.8	
Less: Loss on capital restructuring	-		-		212.4		-		-	
Average cash cost	$ 1,717.7	$ 43.10	$ 1,653.0	$ 42.33	$ 1,506.8	$ 35.62	$ 1,233.4	$ 30.50	$ 1,155.6	$ 28.23

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

The following Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") is intended to help the reader understand Massey Energy Company, our operations and our present business environment. MD&A is provided as a supplement to, and should be read in conjunction with, our consolidated financial statements and the accompanying notes thereto contained in Item 8 of this report. From time to time, we may make statements that may constitute "forward-looking statements" within the meaning of the "safe-harbor" provisions of the Private Securities Litigation Reform Act of 1995. These statements are based on our then current expectations and are subject to a number of risks and uncertainties that could cause actual results to differ materially from those addressed in the forward-looking statements. Please see "Forward-Looking Statements" on page ii hereto and are incorporated herein and the risk factors that may cause such a difference, which are set forth in Item 1A. Fisk Factors and are incorporated herein.

Executive Overview

We operate coal mines and processing facilities in Central Appalachia, which generate revenues and cash flow through the mining, processing and selling of steam and metallurgical grade coal, primarily of low sulfur content. We also generate income and cash flow through other coal-related businesses. Other revenue is obtained from royalties, rentals, gas well revenues, gains on the sale of non-strategic assets and miscellaneous income.

We reported net income for the year ended December 31, 2007 of $94.1 million, or $1.17 per basic share, compared to net income for 2006 of $41.0 million, or $0.50 per basic share. Net income in 2007 included pre-tax gains totaling approximately $10.3 million related to a reserve exchange with a third party, $33.6 million related to a favorable decision on our appeal of the previous jury decision in the Harman lawsuit and $6.7 million on the sale of a mineral rights override, offset by a $20.0 million non-tax deductible penalty related to a settlement with the EPA. Net income in 2006 included pre-tax gains totaling approximately $30 million related to the sale of our Falcon reserves.

Produced tons sold were 39.9 million in 2007, compared to 39.1 million in 2006. Shipments of metallurgical and industrial coal improved significantly in 2007 over 2006 as productivity improved at underground room and pillar mines because of lower turnover and a more stable workforce, and as performance improved from the railroads shipping this coal. Shipments in 2006 were negatively affected by productivity issues at underground mines, including the loss of six months of production from our Logan County resource group's Aracoma longwall mine due to a fire in January 2006 and geological difficulties at several underground mines, especially at the longwall mines located at our Independence and Sidney resource groups. In 2006, we also experienced railroad congestion due to heightened coal demand and a lack of rail cars as well as a tight labor market that lead to high turnover and inexperienced workers. We produced 39.5 million tons during 2007, compared to 38.6 million tons produced in 2006.

During 2007, Produced coal revenue increased by 8% over the prior year as we benefited from higher utility coal sales prices secured in new coal sales agreements as lower-priced contracts expired and we shipped a larger percentage of higher-priced metallurgical tons in 2007. Our average Produced coal revenue per ton sold in 2007 increased by 5.8% to $51.55 compared to $48.71 in 2006 and by 67.4% over a five-year period compared to $30.79 in 2003. Our average Produced coal revenue per ton in 2007 for metallurgical tons sold increased by 4.8% to $72.49 from $69.20 in 2006.

We experienced a significant increase in costs during the past 5-year period, with Average cash cost per ton sold increasing from $28.23 in fiscal 2003 to $43.10 in fiscal 2007 (a reconciliation of these non-GAAP figures is presented in footnote 4 of Item 6. Selected Financial Data). The increased cost level is primarily due to indirect costs associated with compliance with new safety regulations, increased sales-related costs from the growth in average per ton realization, higher labor costs, mining supplies costs and litigation settlements.

In June 2006, the MINER Act was enacted into law, which, among other things, requires mine-specific emergency response plans, enhanced communication systems, and more available mine rescue teams and provides for larger penalties by MSHA for noncompliance by mine operators. In December 2006, MSHA passed its final rule on Emergency Mine Evacuation, which includes requirements for increased availability and storage of SCSRs; improved emergency evacuation drills and SCSR training and the installation and maintenance of lifelines in underground coal mines. Coal producing states, including West Virginia and Kentucky, passed similar legislation in 2006. While the full cost of compliance remains unknown, we expect to spend a total of $30 million to $40 million from 2006 to 2009 to fully comply with these laws. The growth in cost estimate is a result of further development of regulations plus our proposed expansion, described below. Costs for safety equipment are capitalized in Net Property, Plant and Equipment. Additional substantive legislation is also possible in 2008 with the passage by the United States House of Representatives in January 2008 of the S-MINER Act. The House legislation augments portions of the MINER Act and proposes changes to retreat mining practices, study of substance abuse issues and the use of coal dust monitors to reduce miner respirable dust exposure.

On May 10, 2007, the United States, on behalf of the Administrator of the EPA, filed suit against us and twenty-seven of our subsidiaries in the United States District Court for the Southern District of West Virginia ("District Court"). The suit alleged that a number of our subsidiaries violated the Federal Clean Water Act on thousands of occasions by discharging pollutants in excess of monthly and daily permit limits from 2000 to 2006. On January 17, 2008, a proposed settlement reached with the EPA was filed with the District Court. The settlement, which requires District Court approval, requires us to pay $20 million in penalties and make improvements in our environmental processes. We expect the settlement to be approved by the District Court in the first or second quarter of 2008. We recorded the $20 million in Cost of produced coal revenue in 2007.

On July 2, 2007, a jury awarded damages in favor of Wheeling-Pittsburgh Steel Corporation and Mountain State Carbon, LLC in the amount of $219.9 million, comprised of $119.9 million compensatory and $100 million punitive damages. On July 30, 2007, the court awarded an additional $24 million of pre-judgment interest. We have appealed this decision to the West Virginia Supreme Court of Appeals. We believe that we have raised strong legal arguments in our appeal to the West Virginia Supreme Court of Appeals that create significant uncertainty regarding the ultimate outcome of this matter. Ultimately, we believe it is unlikely any punitive damages will be assessed in this matter. We further believe there is a strong possibility that the West Virginia Supreme Court of Appeals will remand the compensatory damages claim for retrial or significantly reduce the amount of the compensatory damages awarded by the jury.

We believe the range of possible loss in this matter is from $16 million to $244 million, prior to post-judgment interest or other costs. The minimum loss we expect to incur upon final settlement or adjudication is the amount of excess costs incurred by WPS to acquire coal required but not delivered under the contract (plus pre-judgment interest) adjusted for performance excused by events of force majeure. Amounts in excess of this amount may ultimately be awarded if the West Virginia Supreme Court of Appeals upholds the circuit court's decisions, in whole or in part, or if the West Virginia Supreme Court of Appeals remands the case for retrial and a jury awards the plaintiffs an amount in excess of what we have accrued. We are unable to predict the ultimate outcome of this matter and believe there is no amount in the range that is a better estimate than any other amount given the various possible outcomes on appeal and, therefore, the minimum amount in the range has been accrued (included in Other current liabilities). It is reasonably possible that our judgments regarding these matters could change in the near term, resulting in the recording of additional material losses that would affect our operating results and financial position. We posted a $50 million appeal bond with the Court on October 25, 2007, which stays this matter pending disposition of our appeal. Refer to Note 17 to the Notes to Consolidated Financial Statements for further details.

In November 2007, the West Virginia Supreme Court reversed a jury decision in the Harman lawsuit, finding in favor of us and reversing the jury award. Subsequently, on January 24, 2008, the Court approved a motion to rehear the Harman case. We remain confident, however, that the Court will ultimately uphold the November decision as we believe nothing has changed the facts or the law that the Court will consider in reaching its final decision. Reflected in our fourth quarter 2007 results are a positive $22.0 million pre-tax impact recorded in Cost of produced coal revenue and a positive pre-tax impact of $11.6 million recorded in Interest expense stemming from the reversal of accruals that had been previously established in conjunction with the Harman case.

In October 2007, we announced plans to expand production at our Central Appalachian coal mining operations during the next two years. Our two-year internal expansion and cost reduction plan, which began in the fourth quarter of 2007, anticipates developing net additional annual production of 8 million tons in 2010 versus 2007, with the ramp up expected to occur during 2008 and 2009. Additionally, these new tons will be weighted towards metallurgical coal production, which we believe will be cost advantaged versus existing comparable quality competitor production. We expect to fund all of our expansion projects out of existing liquidity and operating cash flow generated in 2008 and 2009, although some equipment may be acquired under operating or capital leases.

Results of Operations

2007 Compared with 2006

Revenues

(In thousands)	Year Ended December 31, 2007	2006	Increase (Decrease)	% Increase (Decrease)
Revenues				
Produced coal revenue	$ 2,054,413	$ 1,902,259	$ 152,154	8%
Freight and handling revenue	167,641	156,531	11,110	7%
Purchased coal revenue	108,191	70,636	37,555	53%
Other revenue	83,278	90,428	(7,150)	(8)%
Total revenues	$ 2,413,523	$ 2,219,854	$ 193,669	9%

The following is a breakdown, by market served, of the changes in produced tons sold and average produced coal revenue per ton sold for 2007 compared to 2006:

(In millions, except per ton amounts)	Year Ended December 31, 2007	2006	Increase (Decrease)	% Increase (Decrease)
Produced tons sold:				
Utility	27.4	27.7	(0.3)	(1)%
Metallurgical	8.5	7.8	0.7	9%
Industrial	4.0	3.6	0.4	11%
Total	39.9	39.1	0.8	2%
Produced coal revenue per ton sold:				
Utility	$45.18	$42.37	$ 2.81	7%
Metallurgical	72.49	69.20	$ 3.29	5%
Industrial	50.82	53.13	$ (2.31)	(4)%
Weighted average	51.55	48.71	$ 2.84	6%

Shipments of metallurgical and industrial coal increased in 2007 compared to 2006, mainly due to improved productivity at underground room and pillar mines resulting from lower turnover and a more stable workforce, and improved performance from the railroads shipping this coal. The average per ton sales price for utility coal continued to improve in 2007, attributable to prices contracted during a period of increased demand for utility coal in the United States. The higher demand resulted in shortages of certain quality utility coal, increasing the market prices of this coal, and allowed us to negotiate agreements containing higher price terms as lower-priced contracts expired. The decrease in average per ton sales price for the industrial market is mainly attributable to lower pricing on sales contracted for 2007 shipments.

Purchased coal revenue increased mainly due to an increase in purchased tons sold from 1.3 million in 2006 to 2.1 million in 2007, offset by a 4% decrease in revenue per ton. We purchase varying amounts of coal to supplement produced coal sales.

Other revenue includes refunds on railroad agreements, royalties related to coal lease agreements, gas well revenue, gains on the sale of non-strategic assets and reserve exchanges, earnings from the sale and operation of a synfuel plant, joint venture revenue and other miscellaneous revenue. Other revenue for 2007 includes a pre-tax gain of $10.3 million on an exchange of coal reserves and $6.7 million on the sale of a mineral rights override. In addition, railroad refunds and royalty income were higher in 2007 than in 2006, offset by lower synfuel earnings in 2007 compared to 2006. Other revenue for 2006 includes a pre-tax gain of $30.0 million on the sale of our Falcon reserves (see Note 4 in the Notes to Consolidated Financial Statements for further discussion).

Costs

(In thousands)	Year Ended December 31, 2007	2006	Increase (Decrease)	% Increase (Decrease)
Costs and expenses				
Cost of produced coal revenue	$ 1,641,774	$ 1,599,092	$ 42,682	3%
Freight and handling costs	167,641	156,531	11,110	7%
Cost of purchased coal revenue	95,241	62,613	32,628	52%
Depreciation, depletion and amortization, applicable to:				
Cost of produced coal revenue	242,755	227,279	15,476	7%
Selling, general and administrative	3,280	3,259	21	1%
Selling, general and administrative	75,845	53,834	22,011	41%
Other expense	7,308	6,240	1,068	17%
Total costs and expenses	$ 2,233,844	$ 2,108,848	$ 124,996	6%

Cost of produced coal revenue increased due to increased sales-related costs on higher produced coal revenues including production royalties and severance taxes, increased supplies costs including diesel fuel and explosives, and higher indirect costs associated with compliance with new safety regulations. Supplies costs increased both due to a commodity driven inflationary increase and overall usage as the volume of produced tons sold increased from 39.1 million tons in 2006 to 39.9 million tons in 2007.

Cost of purchased coal revenue increased due to an increase in purchased tons sold from 1.3 million in 2006 to 2.1 million in 2007, offset by a 4% decrease in average cost of purchased coal per ton.

Selling, general and administrative expenses increased due to higher stock-based and performance-based compensation expenses due to increased stock price value in 2007 and attainment of more performance based compensation targets versus 2006.

Interest

Interest income increased due to higher cash and interest-bearing deposit balances during 2007 as compared to 2006.

Income Taxes

Income tax expense was $35.4 million for 2007 compared with a tax expense of $3.4 million for 2006. The income tax rates for 2007 and 2006 were favorably impacted by percentage depletion allowances and the usage of net operating loss carryforwards. The income tax rate for 2007 was negatively impacted by a nondeductible EPA settlement and an increase in deferred tax asset valuation allowances related principally to federal net operating losses. Also impacting the 2007 income tax rate were favorable adjustments in connection with the closing of a prior period audit by the IRS. The income tax rate in 2006 was also favorably impacted by the adjustment of reserves in connection with the closing of a prior period audit by the IRS. Because of the discrete tax events occurring in 2007, the tax rate for 2007 may not be indicative of future tax rates.

2006 Compared with 2005

Revenues

(In thousands)	Year Ended December 31, 2006	2005	Increase (Decrease)	% Increase (Decrease)
Revenues				
Produced coal revenue	$ 1,902,259	$ 1,777,724	$ 124,535	7%
Freight and handling revenue	156,531	150,898	5,633	4%
Purchased coal revenue	70,636	132,320	(61,684)	(47)%
Other revenue	90,428	143,316	(52,888)	(37)%
Total revenues	$ 2,219,854	$ 2,204,258	$ 15,596	1%

The following is a breakdown, by market served, of the changes in produced tons sold and average produced coal revenue per ton sold for 2006 compared to 2005:

(In millions, except per ton amounts)	Year Ended December 31, 2006	2005	Increase (Decrease)	% Increase (Decrease)
Produced tons sold:				
Utility	27.7	29.2	(1.5)	(5)%
Metallurgical	7.8	9.4	(1.6)	(17)%
Industrial	3.6	3.7	(0.1)	(3)%
Total	39.1	42.3	(3.2)	(8)%
Produced coal revenue per ton sold:				
Utility	$42.37	$36.66	$5.71	16%
Metallurgical	69.20	54.19	15.01	28%
Industrial	53.13	53.19	(0.06)	0%
Weighted average	48.71	42.02	6.69	16%

Shipments in 2006 were negatively affected by productivity issues at underground mines, including the loss of six months of production from our Logan County resource group's Aracoma longwall mine due to a fire in January 2006 and geological difficulties at several underground mines, especially at our Revolution and Rockhouse longwall mines. In 2006, we also experienced railroad congestion due to heightened coal demand and a lack of rail cars and a tight labor market that lead to high turnover and inexperienced workers.

The improvement in our average per ton sales price was attributable to prices contracted during a period of increased demand for all grades of coal in the United States and for metallurgical coal worldwide. The higher demand resulted in shortages of certain coals, increasing the market prices of these coals, and allowed us to negotiate agreements containing higher price terms as our lower-priced sales contracts expired. Increased prices for alternative fuel sources such as oil and natural gas also resulted in higher demand for certain coals. Exports of metallurgical coal decreased by 1.0 million tons, or 19%, to 4.2 million tons for 2006 as compared to 2005 due to lower production.

Purchased coal revenue decreased mainly due to a decrease in purchased tons sold from 2.5 million in 2005 to 1.3 million in 2006, offset by a 3% increase in revenue per ton. We purchase varying amounts of coal to supplement produced coal sales.

Other revenue consists of royalties, rentals, earnings associated with coal handling facilities, gas well revenues, synfuel earnings, gains on the sale of non-strategic assets, contract settlement payments, and miscellaneous income. Other revenue for 2006 includes a pre-tax gain of $30.0 million on the sale of our Falcon reserves (see Note 4 in the Notes to Consolidated Financial Statements for further discussion). Other revenue for 2005 includes a pre-tax gain of $45.9 million related to the sale of our ownership interest in Big Elk Mining Company and a pre-tax gain of $38.2 million on a coal reserves exchange (see Note 4 in the Notes to Consolidated Financial Statements for further discussion).

Costs

(In thousands)	Year Ended December 31, 2006	2005	Increase (Decrease)	% Increase (Decrease)
Costs and expenses				
Cost of produced coal revenue	$ 1,599,092	$ 1,438,494	$ 160,598	11%
Freight and handling costs	156,531	150,898	5,633	4%
Cost of purchased coal revenue	62,613	112,600	(49,987)	(44)%
Depreciation, depletion and amortization, applicable to:				
Cost of produced coal revenue	227,279	230,545	(3,266)	(1)%
Selling, general and administrative	3,259	4,020	(761)	(19)%
Selling, general and administrative	53,834	68,254	(14,420)	(21)%
Other expense	6,240	8,018	(1,778)	(22)%
Loss on capital restructuring	-	212,378	(212,378)	(100)%
Total costs and expenses	$ 2,108,848	$ 2,225,207	$ (116,359)	(5)%

Cost of produced coal revenue on a per ton of coal sold basis increased 19% in 2006 compared with 2005, resulting from a variety of factors including higher labor and benefit costs, higher supply costs, including diesel fuel, explosives, copper and steel prices, productivity issues at several underground mines, including the Revolution and Rockhouse longwall mines, and difficulties encountered in the restart of the Aracoma mine in July 2006. The Aracoma mine experienced a fire in January 2006, which also contributed significantly to the increase in Cost of produced coal revenue. Also negatively impacting Cost of produced coal revenue were higher sales-related costs for production royalties and taxes, and severance and black lung excise taxes associated with the increase in average realized prices. Tons produced during 2006 were 38.6 million compared to 43.1 million during 2005.

Cost of purchased coal revenue decreased mainly due to a decrease in purchased tons sold from 2.5 million in 2005 to 1.3 million in 2006, offset by a 7% increase in average cost of purchased coal per ton.

Selling, general and administrative expenses decreased primarily due to lower stock-based compensation accruals due to changes in the price of the Company's stock and lower performance-linked executive compensation accruals in 2006.

Other expense, which consists of costs associated with the generation of other revenue, such as costs to operate the coal handling facilities, gas wells, and other miscellaneous expenses, decreased due to decreases in operating costs of the gas wells and synfuel facility, while senior note repurchase losses were recognized in 2005.

Interest

Interest income increased due to higher levels of cash reserves during 2006 and higher interest rates received on investments during 2006. Interest expense increased primarily a result of a debt restructuring that occurred in December 2005, which increased debt levels in 2006 compared to 2005, and resulted in a higher effective interest rate. Interest expense in 2005 included a $6.6 million write-off of previously unamortized debt issuance costs related to our debt restructuring.

Income Taxes

The income tax rate for 2006 was favorably impacted by percentage depletion allowances, the usage of a net operating loss carryforward and the adjustment of reserves in connection with the closing of a prior period audit by the IRS. The income tax rate for 2005 was negatively impacted by the non-deductibility on the early payout of deferred compensation ($7.5 million tax effect) and the non-deductibility on our debt repurchases and exchange offers during the fourth quarter. The tax rate for 2005 was favorably impacted by percentage depletion allowances, the usage of a net operating loss carry forward, the adjustment of reserves in connection with the closing of a prior period audit by state taxing authorities and the IRS and the closing of a federal statutory period. Because of the discrete tax events occurring in 2006 and 2005, the tax rates for 2006 and 2005 may not be indicative of future tax rates.

Liquidity and Capital Resources

At December 31, 2007, our available liquidity was $479.3 million, which consisted of cash and cash equivalents of $365.2 million and $114.1 million availability under the asset-backed liquidity facility.

Debt was comprised of the following:

	December 31, 2007	December 31, 2006
	(In Thousands)	
6.875% senior notes due 2013, net of discount	$ 755,401	$ 754,804
6.625% senior notes due 2010	335,000	335,000
2.25% convertible senior notes due 2024	9,647	9,647
4.75% convertible senior notes due 2023	730	730
Capital lease obligations	8,823	11,232
Fair value hedge adjustment	(5,054)	(6,506)
Total debt	1,104,547	1,104,907
Amounts due within one year	(1,875)	(2,583)
Total long-term debt	$ 1,102,672	$ 1,102,324

See Note 6 in the Notes to Consolidated Financial Statements for further discussion of our debt and debt-related covenants.

Asset-Based Credit Facility

On August 15, 2006, we amended and restated our asset-based revolving credit agreement, which provides for available borrowings, including letters of credit, of up to $175 million, depending on the level of eligible inventory and accounts receivable. The previous credit limit was $130 million, including a $100 million sublimit for letters of credit. In addition, we achieved improved pricing and extended the facility's maturity to August 2011. As of December 31, 2007, there were $60.9 million of letters of credit issued and there were no outstanding borrowings under this facility.

Debt Ratings

Moody's Investors Service ("Moody's") and Standard & Poor's Rating Services ("S&P") rate our long-term debt. As of December 31, 2007, our S&P outlook rating is Stable. Moody's outlook on all of our notes is Stable; our Corporate Family Rating is B1.

Current Ratings:	Moody's	S&P
6.875% Notes	B2	B+
6.625% Notes	B2	B+
2.25% Notes	B2	B+
4.75% Notes	B3	B-

Cash Flow

Net cash provided by operating activities was $396.0 million for 2007 compared to $214.5 million for 2006. Cash provided by operating activities reflects Net income adjusted for non-cash charges and changes in working capital requirements. Cash provided by operating activities for 2007 includes $34.1 million of payments for income taxes.

Net cash utilized by investing activities was $242.3 million and $246.7 million for 2007 and 2006, respectively. The cash used in investing activities reflects capital expenditures in the amount of $270.5 million and $298.1 million for 2007 and 2006, respectively. These capital expenditures are for replacement of mining equipment, the expansion of mining and shipping capacity, and projects to improve the efficiency of mining operations. Included in these capital expenditures are $3.0 million and $25.3 million of cash spent for the buyout of operating leases in 2007 and 2006, respectively. Additionally, 2007 and 2006 included $28.1 million and $51.5 million, respectively, of proceeds provided by the sale of assets. Proceeds from the sale of assets for 2006 included $30.8 million in cash related to the sale of our Falcon reserves (see Note 4 to the Notes to Consolidated Financial Statements for further discussion).

Financing activities primarily reflect changes in debt levels for 2007 and 2006, as well as the exercising of stock options and payments of dividends. Net cash utilized by financing activities was $27.7 million for 2007 compared to $48.0 million for 2006. Financing activities for 2007 and 2006 included $30 million and $50 million, respectively, for the repurchase of 1.6 and 1.3 million shares, respectively, of Common Stock under the share repurchase program discussed below. We generated $13.1 million from several sale-leaseback (operating leases) transactions of certain mining equipment in 2007, compared to $21.8 million of sale-leasebacks (operating leases) in 2006.

We believe that cash on hand, cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, scheduled debt payments, potential share repurchases, anticipated dividend payments, expected settlements and final awards of outstanding litigation, and anticipated capital expenditures including planned expansions (other than major acquisitions) for at least the next few years. Nevertheless, our ability to satisfy our debt service obligations, repurchase shares, pay dividends, pay settlements and final awards of outstanding litigation, or fund planned capital expenditures including planned expansions, will substantially depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry, debt covenants, and financial, business and other factors, some of which are beyond our control. We frequently evaluate potential acquisitions. In the past, we have funded acquisitions primarily with cash generated from operations, but we may consider a variety of other sources, depending on the size of any transaction, including debt or equity financing. Additional capital resources may not be available to us on terms that we find acceptable, or at all.

Share Repurchases

The Board of Directors has authorized a total of $500 million (excluding commissions) to repurchase our common stock under our share repurchase program. Share repurchases of $50 million using cash on hand were completed on June 8, 2006, with the purchase of 1,299,000 shares of Common Stock at an average price of $38.47 per share. In August 2007, 1,575,800 shares of Common Stock were purchased at an average price of $19.01 per share. As of December 31, 2007, we had $420 million available under the current authorization. We may repurchase our common stock from time to time in compliance with the SEC's regulations and other legal requirements, and subject to market conditions and other factors. The share repurchase program does not require us to acquire any specific number of shares and may be terminated at any time.

The following table summarizes information about shares of Common Stock that were purchased during the fourth quarter of 2007.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plan
October 1 through October 31	-	-	-	-
November 1 through November 30	-	-	-	-
December 1 through December 31	-	-	-	-
Total	-		-	11,339,093 (1)

(1) Calculated using $420 million that may yet be purchased under our share repurchase program and $37.04, the closing price of Common Stock as reported on the New York Stock Exchange on January 31, 2008.

Contractual Obligations

We have various contractual obligations that are recorded as liabilities within the Consolidated Financial Statements in this Annual Report on Form 10-K. Other obligations, such as certain purchase commitments, operating lease agreements, and other executory contracts are not recognized as liabilities within the Consolidated Financial Statements but are required to be disclosed. The following table is a summary of our significant obligations as of December 31, 2007 and the future periods in which such obligations are expected to be settled in cash. The table does not include current liabilities accrued within the Consolidated Financial Statements, such as Accounts payable and Payroll and employee benefits.

	Payments Due by Period (In Thousands)				
	Total	Within 1 Year	1-3 Years	3-5 Years	Beyond 5 Years
Long-term debt [1]	$ 1,489,251	$ 74,695	$ 484,391	$ 105,003	$ 825,162
Capital lease obligations [2]	9,736	2,430	4,651	2,655	-
Operating lease obligations [3]	161,331	42,669	73,704	39,080	5,878
Coal lease obligations [4]	188,129	16,788	30,974	25,104	115,263
Purchased coal obligations [5]	127,389	67,749	59,640	-	-
Other purchase obligations [6]	317,954	266,153	29,385	12,624	9,792
Total Obligations	$ 2,293,790	$ 470,484	$ 682,745	$ 184,466	$ 956,095

(1) Long-term debt obligations reflect the future interest and principal payments of our fixed rate senior unsecured notes outstanding as of December 31, 2007. See Note 6 to the Notes to Consolidated Financial Statements for additional information.

(2) Capital lease obligations include the amount of imputed interest over the terms of the leases. See Note 13 to the Notes to Consolidated Financial Statements for additional information.

(3) See Note 13 to the Notes to Consolidated Financial Statements for additional information.

(4) Coal lease obligations include minimum royalties paid on leased coal rights. Certain coal leases do not have set expiration dates but extend until completion of mining of all merchantable and mineable coal reserves. For purposes of this table, we have generally assumed that minimum royalties on such leases will be paid for a period of 20 years.

(5) Purchased coal obligations represent commitments to purchase coal from external production sources under firm contracts as of December 31, 2007.

(6) Other purchase obligations primarily include capital expenditure commitments for surface mining and other equipment as well as purchases of materials and supplies. We have purchase agreements with vendors for most types of operating expenses. However, our open purchase orders (which are not recognized as a liability until the purchased items are received) under these purchase agreements, combined with any other open purchase orders, are not material and are excluded from this table. Other purchase obligations also include contractual commitments under transportation contracts. Since the actual tons to be shipped under these contracts are not set and will vary, the amount included in the table reflects the minimum payment obligations required by the contracts.

Additionally, we have liabilities relating to pension and other postretirement benefits, work related injuries and illnesses, and mine reclamation and closure. As of December 31, 2007, payments related to these items are estimated to be:

Payments Due by Years (In Thousands)		
Within 1 Year	1 - 3 Years	3 - 5 Years
$68,032	$127,178	$134,792

Our determination of these noncurrent liabilities is calculated annually and is based on several assumptions, including then prevailing conditions, which may change from year to year. In any year, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. Moreover, in particular for periods after 2007, the estimates may change from the amounts included in the table, and may change significantly, if assumptions change to reflect changing conditions. These assumptions are discussed in the Notes to Consolidated Financial Statements and in Critical Accounting Estimates and Assumptions of this Management's Discussion and Analysis of Financial Condition and Results of Operations section.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements including guarantees, operating leases, indemnifications, and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in the consolidated balance sheets, and, except for the operating leases, which are discussed in Note 13 to the Notes to Consolidated Financial Statements, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

From time to time we use bank letters of credit to secure our obligations for workers' compensation programs, various insurance contracts and other obligations. At December 31, 2007, we had $106.0 million of letters of credit outstanding of which $45.1 million was collateralized by $46.0 million of cash deposited in restricted, interest bearing accounts pledged to issuing banks and $60.9 million was issued under our asset based lending arrangement. No claims were outstanding against those letters of credit as of December 31, 2007.

On January 22, 2008, a settlement was reached regarding our previously reported disagreement and protest of a new actuarial methodology being applied by the Office of Workers' Claims ("OWC") for the Commonwealth of Kentucky in determining levels of surety against potential future claims. The settlement resulted in the dismissal of our cases pending in the Franklin County Circuit Court of Kentucky and required us to post additional surety of $11.5 million for the 2006 and 2007 assessments against potential claims. That additional surety requirement was satisfied with the posting of a letter of credit issued under our asset-based lending arrangement.

We use surety bonds to secure reclamation, workers' compensation, wage payments, and other miscellaneous obligations. As of December 31, 2007, we had $364.1 million of outstanding surety bonds. These bonds were in place to secure obligations as follows: post-mining reclamation bonds of $304.7 million, an appeal bond of $50.0 million, and other miscellaneous obligation bonds of $9.4 million. Outstanding surety bonds of $46.1 million are secured with letters of credit. In addition, in October 2007, we deposited $50.0 million into an interest bearing account which is pledged to an insurance company that issued the $50.0 million appeal bond in the Wheeling-Pitt legal matter (see Note 17 to Notes to Consolidated Financial Statements for additional details). The $50.0 million is reported in Deposits within Other current assets.

Generally, the availability and market terms of surety bonds continue to be challenging. If we are unable to meet certain financial tests applicable to some of our surety bonds, or to the extent that surety bonds otherwise become unavailable, we would need to replace the surety bonds or seek to secure them with letters of credit, cash deposits, or other suitable forms of collateral.

Certain Trends and Uncertainties

Our inability to satisfy contractual obligations may adversely affect profitability.

From time to time, we have disputes with customers over the provisions of sales agreements relating to, among other things, coal pricing, quality, quantity, delays and force majeure declarations. Our inability to satisfy contractual obligations could result in the purchase of coal from third party sources to satisfy those obligations, the negotiation of settlements with customers, which may include price reductions, the reduction of commitments or the extension of the time for delivery, and customers terminating contracts, declining to do future business with us, or initiating claims against us. We may not be able to resolve all of these disputes in a satisfactory manner, which could result in the payment of substantial damages or otherwise harm our relationships with our customers.

The planned expansion of our coal production involves a number of risks, any of which could cause us not to realize the anticipated benefits.

In October 2007, we announced plans to expand production at our Central Appalachian coal mining operations during the next two years. Our two-year internal expansion and cost reduction plan anticipates developing net additional annual production of 8 million tons in 2010 versus 2007, with the ramp up occurring during 2008 and 2009. Additionally, these new tons will be weighted towards metallurgical coal production, which we believe will be cost advantaged versus existing comparable quality competitor production. We expect to fund all of our expansion projects out of existing liquidity and operating cash flow generated in 2008 and 2009. If we are unable to successfully expand our coal production, our profitability may decline and we could experience a material adverse effect on our cash flows, results of operations or financial condition. These expansion plans involve certain risks, including:

- the accuracy of our assumptions of the recoverability of the coal reserves to be mined;
- assumptions about the availability of skilled labor to staff the new and expanded mines;
- assumptions about the availability and cost of the capital equipment required for each of the new and expanded mines; and

- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for expanding our production.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from our expansion plans. Our expansion plans could materially affect our liquidity and capital resources and may require us to incur indebtedness, seek equity, capital or both.

We are subject to being adversely affected by the potential inability to renew or obtain surety bonds.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers' compensation, and to satisfy other miscellaneous obligations. These bonds are typically renewable annually. Surety bond issuers and holders may not continue to renew the bonds or may demand additional collateral upon those renewals. We are also subject to increases in the amount of surety bonds required by federal and state laws as these laws change or the interpretation of these laws changes. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal law would have a material impact on us. That failure could result from a variety of factors including the following: (i) lack of availability, higher expense or unfavorable market terms of new bonds; (ii) restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our senior notes or revolving credit facilities; (iii) our inability to meet certain financial tests with respect to a portion of the post-mining reclamation bonds; and (iv) the exercise by third-party surety bond issuers of their right to refuse to renew or issue new bonds.

Shortages of skilled labor in the Central Appalachian coal industry may pose a risk in achieving high levels of productivity at competitive costs.

Coal mining continues to be a labor-intensive industry. In recent years, we have encountered a shortage of experienced mine workers when the demand and prices for all specifications of coal we mine increased appreciably. The hiring of these less experienced workers has negatively impacted our productivity and cash costs. A continued lack of skilled miners could continue to have an adverse impact on our labor productivity and cost and our ability to meet current production requirements to fulfill existing sales commitments or to expand production to meet the increased demand for coal.

Inflationary pressures on supplies and labor may adversely affect our profit margins.

Generally, inflation in the United States has been relatively low in recent years. However, over the course of the last two years, we have been significantly impacted by price inflation in many of the components of our Cost of produced coal revenue, such as fuel, steel, copper and labor. For instance, the prices of diesel fuel and copper each increased approximately 20% over the two-year period ending December 31, 2007. If the prices for which we sell our coal do not increase in step with rising costs, our profit margins will be reduced.

Critical Accounting Estimates and Assumptions

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts. These estimates and assumptions are based on information available as of the date of the financial statements. Significant changes to the estimates and assumptions used in determining certain liabilities described below could introduce substantial volatility to our costs. The following critical accounting estimates and assumptions were used in the preparation of the financial statements:

Defined Benefit Pension Plans

The estimated cost and benefits of non-contributory defined benefit pension plans are determined by independent actuaries, who, with management's review and approval, use various actuarial assumptions, including discount rate, future rate of increase in compensation levels and expected long-term rate of return on pension plan assets. The discount rate is an estimate of the current interest rate at which the applicable liabilities could be effectively settled as of the measurement date. In estimating the discount rate, forecasted cash flows were discounted using each year's associated spot interest rate on high quality fixed income investments. At December 31, 2007 and 2006, the discount rate used to determine defined benefit pension liability was 6.50% and 5.90%, respectively. The impact of lowering the discount rate 0.25% for 2007 would have increased the 2007 net periodic pension expense by approximately $1.7 million. The rate of increase in compensation levels is determined based upon our long-term plans for such increases. The rate of increase in compensation levels used was 4.0% for the years ended December 31, 2007 and 2006. The expected long-term rate of return on pension plan assets is based on long-term historical return information and future estimates of long-term investment returns for the target asset allocation of investments that comprise plan assets. The expected long-term rate of return on plan assets used to determine expense in each period was 8.0% for each of the years ended December 31, 2007, 2006 and 2005, respectively. A 0.5% decrease in the expected long-term rate of return assumption would have increased the 2007 net periodic pension expense by approximately $1.4 million. The actuarial assumptions we use may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. While we believe that the assumptions used are appropriate, differences in actual experience or changes in assumptions might materially affect our financial position or results of operations. See Note 5 to the Notes to Consolidated Financial Statements for further discussion on our pension plans.

Coal Workers' Pneumoconiosis

We are responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, and various states' statutes, for the payment of medical and disability benefits to eligible recipients resulting from occurrences of coal workers' pneumoconiosis disease (black lung). An annual evaluation is prepared by independent actuaries, who, after review and approval by management, use various assumptions regarding disability incidence, medical costs trend, cost of living trend, mortality, death benefits, dependents and interest rates. We record expense related to this obligation using the service cost method. At December 31, 2007 and December 31, 2006, the discount rate used to determine the black lung liability was 6.50% and 5.90%, respectively. Included in Note 11 to the Notes to Consolidated Financial Statements is a medical cost trend and cost of living trend sensitivity analysis.

Workers' Compensation

Our operations have workers' compensation coverage through a combination of either self-insurance, participation in a state run program, or commercial insurance. We accrue for the self-insured liability by recognizing cost when it is probable that the liability has been incurred and the cost can be reasonably estimated. To assist in the determination of this estimated liability we utilize the services of third party administrators who derive claim reserves from historical experience. These third parties provide information to independent actuaries, who after review and consultation with management with regards to actuarial assumptions, including discount rate, prepare an evaluation of the self-insured liabilities. At December 31, 2007 and December 31, 2006, the discount rate used to determine the self-insured workers' compensation liability obligation was 5.00%. A decrease in the assumed discount rate increases the workers' compensation self-insured liability and related expense. Actual experience in settling these liabilities could differ from these estimates, which could increase our costs. See Note 11 to the Notes to Consolidated Financial Statements for further discussion on workers' compensation.

Other Postretirement Benefits

Our sponsored health care plans provide retiree health benefits to eligible union and non-union retirees who have met certain age and service requirements. Depending on year of retirement, benefits may be subject to annual deductibles, coinsurance requirements, lifetime limits, and retiree contributions. These plans are not funded. We pay costs as incurred by participants. The estimated cost and benefits of the retiree health care plans are determined by independent actuaries, who, after review and approval by management, use various actuarial assumptions, including discount rate, expected trend in health care costs and per capita claims costs. At December 31, 2007 and December 31, 2006, the discount rate used to determine the other postretirement benefit liability was 6.50% and 5.90%, respectively. The impact of lowering the discount rate 0.25% for 2007 would have increased the 2007 net periodic postretirement benefit cost by approximately $0.4 million. At December 31, 2007, our assumptions of the company health care plans' cost trend were projected at an annual rate of 8.5% ranging down to 5.0% by 2013 (8.2% ranging down to 5.0% by 2011 at December 31, 2006), and remaining level thereafter. The impact of increasing the health care cost trend rate by 1.0% would have increased the 2007 net periodic postretirement benefit cost by approximately $2.0 million. Included in Note 10 to the Notes to Consolidated Financial Statements is a sensitivity analysis on the health care trend rate assumption.

Reclamation and Mine Closure Obligations

The SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Total reclamation and mine-closing liabilities are based upon permit requirements and engineering estimates related to these requirements. We account for our reclamation liabilities under SFAS 143. SFAS 143 requires that asset retirement obligations be recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows. Management and engineers periodically review the estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed. In estimating future cash flows, we considered the estimated current cost of reclamation and applied inflation rates and a third party profit, as necessary. The third party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The discount rate applied is based on the rates of treasury bonds with maturities similar to the estimated future cash flow, adjusted for our credit standing. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

Contingencies

We are parties to a number of legal proceedings, incident to our normal business activities. These matters include contract disputes, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates, we do not believe that any liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition.

However, it is reasonably possible that the ultimate liabilities in the future with respect to these lawsuits and claims may be material to our cash flows, results of operations or financial condition. See Item 3. Legal Proceedings and Note 17 to the Notes to Consolidated Financial Statements for further discussion on our contingencies.

Income Taxes

We account for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"), as interpreted by FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48"), which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. SFAS 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including tax attribute carrybacks, the future reversals of existing taxable temporary differences, the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in the evaluation of our valuation allowance, we record a change in valuation allowance through income tax expense in the period such determination is made.

Under FIN 48, we establish reserves based upon management's assessment of exposure associated with tax positions taken relative to temporary and permanent tax differences and tax credits, plus penalties and interest on the accrued uncertain tax positions. The tax reserves are analyzed periodically and adjustments are made as events occur to warrant adjustment to the reserves. We are currently under audit from the IRS for the calendar years ended December 31, 2003 and 2004. Management believes that we have adequately provided for any income taxes and penalties and interest that may ultimately be paid with respect to all open tax years.

Coal Reserve Values

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves. Many of these uncertainties are beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our internal engineers, geologists and financial associates. Some of the factors and assumptions that impact economically recoverable reserve estimates include: (i) geological conditions; (ii) historical production from similar areas with similar conditions; (iii) the assumed effects of regulations and taxes by governmental agencies; (iv) assumptions governing future prices; and (v) future operating costs.

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal attributable to a particular group of properties, and classifications of these reserves based on risk of recovery and estimates of future net cash flows, may vary substantially. Actual production, revenue and expenditures with respect to reserves will likely vary from estimates, and these variances may be material. Variances would effect both the Consolidated Statements of Income, in the form of revenue and expenditures, as well as the Consolidated Balance Sheets, in the form of valuation of coal reserves, depletion rates and potential impairment.

Recent Accounting Pronouncements

Refer to Note 1 in the Notes to Consolidated Financial Statements for information concerning the effect of recent accounting pronouncements.

Item 7A. Quantitative and Qualitative Discussions about Market Risk

Our net interest expense is sensitive to changes in the general level of short-term interest rates. At December 31, 2007, the outstanding $1,104.5 million of our debt was under fixed-rate instruments. Upon the termination of our $240 million interest rate swap agreement in December 2005, our interest expense is no longer sensitive to changes in the general level of short-term interest rates. However, if it should become necessary to borrow under our asset-based revolving credit facility, those borrowings would be made at a variable rate. Interest income is sensitive to changes in short-term interest rates. Assuming that Cash and cash equivalents was fixed at the December 31, 2007 level of $365.2 million, a hypothetical 100 basis point decrease in money market interest rates would result in a decrease of approximately $3.7 million in Interest income.

We manage market price risk for coal through the use of long-term coal supply agreements, which are contracts with a term of one year or more in duration, rather than through the use of derivative instruments. We estimate that the percentage of sales pursuant to these long-term contracts was 95% for our fiscal year ended December 31, 2007. We anticipate that in 2008, the percentage of our sales pursuant to long-term contracts will be comparable with the percentage of our sales for 2007. The prices for coal shipped under long-term contracts may be below the current market price for similar types of coal at any given time. As a consequence of the substantial volume of our sales that are subject to these long-term agreements, we have less coal available with which to capitalize on 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.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Massey Energy Company

We have audited the accompanying consolidated balance sheets of Massey Energy Company as of December 31, 2007 and 2006, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Massey Energy Company at December 31, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 7 to the consolidated financial statements, in 2007 the Company changed its method for accounting for income taxes to comply with the accounting provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*. As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for post-production stripping costs to comply with the accounting provisions of Emerging Issues Task Force No. 04-6, *Accounting for Stripping Costs Incurred During Production in the Mining Industry*. As discussed in Notes 5, 10 and 11 to the consolidated financial statements, in 2006 the Company changed its method of accounting for defined benefit pension and other post-retirement plans to comply with the accounting provisions of Financial Accounting Standards Board Statement No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans – an Amendment of FASB Statement Nos. 87, 77, 106, and 132(R)*. As discussed in Note 12 to the consolidated financial statements, in 2006 the Company changed its method of accounting for stock-based compensation to comply with the accounting provisions of Financial Accounting Standards Board Statement No. 123(R), *Share- Based Payment*.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Massey Energy Company's internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Richmond, Virginia
February 28, 2008

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(In Thousands, Except Per Share Amounts)

	Year Ended		
	December 31, 2007	December 31, 2006	December 31, 2005
Revenues			
Produced coal revenue	$ 2,054,413	$ 1,902,259	$ 1,777,724
Freight and handling revenue	167,641	156,531	150,898
Purchased coal revenue	108,191	70,636	132,320
Other revenue	83,278	90,428	143,316
Total revenues	2,413,523	2,219,854	2,204,258
Costs and expenses			
Cost of produced coal revenue	1,641,774	1,599,092	1,438,494
Freight and handling costs	167,641	156,531	150,898
Cost of purchased coal revenue	95,241	62,613	112,600
Depreciation, depletion and amortization, applicable to:			
Cost of produced coal revenue	242,755	227,279	230,545
Selling, general and administrative	3,280	3,259	4,020
Selling, general and administrative	75,845	53,834	68,254
Other expense	7,308	6,240	8,018
Loss on capital restructuring	-	-	212,378
Total costs and expenses	2,233,844	2,108,848	2,225,207
Income (Loss) before interest and taxes	179,679	111,006	(20,949)
Interest income	23,969	20,094	12,603
Interest expense	(74,145)	(86,076)	(67,064)
Income (Loss) before taxes	129,503	45,024	(75,410)
Income tax expense	(35,405)	(3,408)	(26,228)
Income (Loss) before cumulative effect of accounting change	94,098	41,616	(101,638)
Cumulative effect of accounting change, net of tax	-	(639)	-
Net income (loss)	$ 94,098	$ 40,977	$ (101,638)
Income (Loss) per share - Basic			
Income (Loss) before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)
Cumulative effect of accounting change	-	(0.01)	-
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)
Income (Loss) per share - Diluted			
Income (Loss) before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)
Cumulative effect of accounting change	-	(0.01)	-
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)
Shares used to calculate income per share			
Basic	80,123	80,847	76,390
Diluted	80,654	81,386	76,390

See Notes to Consolidated Financial Statements

MASSEY ENERGY COMPANY
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Amounts)

	December 31, 2007	December 31, 2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 365,220	$ 239,245
Trade and other accounts receivable, less allowance of $444 and $576, respectively	156,572	197,105
Inventories	183,360	191,056
Income taxes receivable	16,302	-
Other current assets	165,940	172,322
Total current assets	887,394	799,728
Net Property, Plant and Equipment	1,793,920	1,776,781
Other Noncurrent Assets		
Pension assets	47,323	34,974
Other noncurrent assets	132,034	129,213
Total other noncurrent assets	179,357	164,187
Total assets	$ 2,860,671	$ 2,740,696
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable, principally trade and bank overdrafts	$ 148,206	$ 117,157
Short-term debt	1,875	2,583
Payroll and employee benefits	46,512	40,380
Income taxes payable	-	19,412
Other current liabilities	171,269	175,005
Total current liabilities	367,862	354,537
Noncurrent Liabilities		
Long-term debt	1,102,672	1,102,324
Deferred income taxes	154,705	116,690
Other noncurrent liabilities	451,428	469,854
Total noncurrent liabilities	1,708,805	1,688,868
Total liabilities	2,076,667	2,043,405
Shareholders' Equity		
Capital stock		
Preferred – authorized 20,000,000 shares without par value; none issued	-	-
Common – authorized 150,000,000 shares of $0.625 par value; issued 82,818,578 and 82,365,259 shares, respectively	51,743	51,458
Treasury stock, 2,874,800 and 1,299,000 shares at cost, respectively	(79,986)	(49,995)
Additional capital	237,684	220,650
Retained earnings	601,587	515,894
Accumulated other comprehensive loss	(27,024)	(40,716)
Total shareholders' equity	784,004	697,291
Total liabilities and shareholders' equity	$ 2,860,671	$ 2,740,696

See Notes to Consolidated Financial Statements.

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
Cash Flows from Operating Activities			
Net income (loss)	$ 94,098	$ 40,977	$ (101,638)
Adjustments to reconcile Net income (loss) to Cash provided by operating activities:			
Cumulative effect of accounting change	-	639	-
Depreciation, depletion and amortization	246,035	230,538	234,565
Share-based compensation expense	19,299	7,350	-
Deferred income taxes	27,403	(17,381)	23,259
Gain on disposal of assets	(6,751)	(46,557)	(63,879)
Gain on reserve exchange	(10,284)	-	(38,198)
Loss on repurchase of senior notes	-	-	669
Loss on debt restructuring	-	-	212,378
Writeoff of deferred financing costs	-	-	6,648
Accretion of asset retirement obligations	11,758	10,166	10,156
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable	19,253	(43,456)	13,559
Decrease (increase) in inventories	7,696	(8,070)	(85,869)
Decrease (increase) in other current assets	6,382	24,573	(4,695)
(Increase) decrease in pension and other assets	(191)	1,165	(6,830)
Increase (decrease) in accounts payable and bank overdrafts	31,049	(45,632)	26,917
(Decrease) increase in accrued income taxes	(35,714)	42,638	15,320
(Decrease) increase in other accrued liabilities	(558)	17,046	19,502
(Decrease) increase in other noncurrent liabilities	(2,416)	4,712	12,140
Asset retirement obligation payments	(11,061)	(4,205)	(3,858)
Cash provided by operating activities	395,998	214,503	270,146
Cash Flows from Investing Activities			
Capital expenditures	(270,461)	(298,132)	(346,578)
Proceeds from sale of assets	28,118	51,467	73,542
Cash utilized by investing activities	(242,343)	(246,665)	(273,036)
Cash Flows from Financing Activities			
Repurchase of senior notes	-	-	(19,890)
Stock repurchase	(29,991)	(49,995)	-
Repayments of capital lease obligations	(2,409)	(10,214)	(19,370)
Proceeds from issuance of 6.875% senior notes	-	-	742,847
Debt restructuring	-	-	(562,608)
Early termination of fair value hedge	-	-	(7,922)
Proceeds from sale-leaseback transactions	13,146	21,819	71,697
Cash dividends paid	(12,837)	(12,814)	(12,208)
Proceeds from stock options exercised	4,001	2,142	7,231
Excess income tax benefit from stock option exercises	410	1,051	-
Cash (utilized) provided by financing activities	(27,680)	(48,011)	199,777
Increase (decrease) in cash and cash equivalents	125,975	(80,173)	196,887
Cash and cash equivalents at beginning of period	239,245	319,418	122,531
Cash and cash equivalents at end of period	$ 365,220	$ 239,245	$ 319,418
Supplemental Cash Flow Information			
Cash paid during the period for income taxes	$ 34,052	$ 157	$ 9,205

See Notes to Consolidated Financial Statements.

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(In Thousands, Except Per Share Amounts)

	Common Stock Shares	Common Stock Amount	Additional Capital	Unamortized Executive Stock Plan Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock	Total Shareholders' Equity
Balance at December 31, 2004	76,431	$ 47,769	$ 39,925	$ (6,162)	$ 695,492	$ (151)	$ -	$ 776,873
Net loss					(101,638)			(101,638)
Other comprehensive loss, net of deferred tax of $171:								
Minimum pension liability adjustment						(318)		(318)
Comprehensive loss								(101,956)
Dividends declared ($0.16 per share)					(12,233)			(12,233)
Exercise of stock options	498	312	6,919					7,231
Stock option tax benefit			2,563					2,563
Amortization of stock plan expense				3,153				3,153
Issuance of restricted stock, net	90	56	4,065	(4,121)				-
Issuance of stock for debt conversion	4,921	3,076	162,277					165,353
Balance at December 31, 2005	81,940	$ 51,213	$ 215,749	$ (7,130)	$ 581,621	$ (469)	$ -	$ 840,984
Net income					40,977			40,977
Other comprehensive income, net of deferred tax of $(21):								
Minimum pension liability adjustment						109		109
Comprehensive income								41,086
Adoption of accounting standards:								
Share-based payments			(7,130)	7,130				-
Post-production stripping costs, net of deferred tax of $59,970					(93,798)			(93,798)
Pension and postretirement plans, net of deferred tax of $25,801						(40,356)		- (40,356)
Dividends declared ($0.16 per share)					(12,906)			(12,906)
Stock option expense			6,112					6,112
Exercise of stock options	185	115	2,027					2,142
Stock option tax benefit			1,051					1,051
Restricted stock	239	129	2,822					2,951
Share repurchase	(1,299)						(49,995)	(49,995)
Issuance of stock for debt conversion	1	1	19					20
Balance at December 31, 2006	81,066	$ 51,458	$ 220,650	$ -	$ 515,894	$ (40,716)	$ (49,995)	$ 697,291
Net income					94,098			94,098
Other comprehensive income:								
Pension and postretirement plans, net of deferred tax of $8,754						13,692		13,692
Comprehensive income								107,790
Adoption of accounting standards:								
Uncertainty in income taxes					5,182			5,182
Dividends declared ($0.17 per share)					(13,587)			(13,587)
Stock option expense			8,308					8,308
Exercise of stock options	299	188	3,813					4,001
Stock option tax benefit			410					410
Restricted stock	155	97	4,503					4,600
Share repurchase	(1,576)						(29,991)	(29,991)
Balance at December 31, 2007	79,944	$ 51,743	$ 237,684	$ -	$ 601,587	$ (27,024)	$ (79,986)	$ 784,004

See Notes to Consolidated Financial Statements.

1. Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements include the accounts of Massey Energy Company ("we", "our", or "us"), its wholly owned and sole, direct operating subsidiary A.T. Massey Coal Company, Inc. ("A.T. Massey") and A.T. Massey's wholly owned direct and indirect subsidiaries. Inter-company transactions and accounts are eliminated in consolidation. We have no independent assets or operations. We do not have a controlling interest in any separate independent operations. Investments in business entities in which we do not have control, but have the ability to exercise significant influence over the operating and financial policies, are accounted for under the equity method.

A.T. Massey fully and unconditionally guarantees our obligations under the 6.625% senior notes due 2010 ("6.625% Notes"), the 6.875% senior notes due 2013 ("6.875% Notes"), the 4.75% convertible senior notes due 2023 ("4.75% Notes") and the 2.25% convertible senior notes due 2024 ("2.25% Notes"). In addition, the 6.625% Notes, the 6.875% Notes and the 2.25% Notes are fully and unconditionally, jointly and severally guaranteed by A.T. Massey and substantially all of our indirect operating subsidiaries, each such subsidiary being indirectly 100% owned by us. The subsidiaries not providing a guarantee of the 6.625% Notes, the 6.875% Notes and the 2.25% Notes are minor (as defined under Securities and Exchange Commission ("SEC") Rule 3-10(h)(6) of Regulation S-X). See Note 6 for a more complete discussion of debt.

Use of Estimates

The preparation of the financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect reported amounts. These estimates are based on information available as of the date of the financial statements. Therefore, actual results could differ from those estimates. The most significant estimates used in the preparation of the consolidated financial statements are related to defined benefit pension plans, coal workers' pneumoconiosis ("black lung"), workers' compensation, other postretirement benefits, reclamation and mine closure obligations, contingencies, income taxes, coal reserve estimates and stock options.

Revenue Recognition

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

Freight and handling revenue consists of shipping and handling costs invoiced to coal customers and paid to third-party carriers. These revenues are directly offset by Freight and handling costs.

Purchased coal revenue represents revenue recognized from the sale of coal purchased from third-party production sources. We take title to the purchased coal, which we then resell to our customers. Typically, title and risk of loss transfer to the customer at the mine, dock or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s).

Other revenue includes refunds on railroad agreements, royalties related to coal lease agreements, gas well revenue, gains on the sale of non-strategic assets and reserve exchanges, earnings from the sale and operation of a synfuel plant, joint venture revenue and other miscellaneous revenue. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced. Certain agreements require minimum lease payments regardless of the extent to which minerals are produced from the leasehold. The terms of these agreements generally range from specified periods of 5 to 10 years, or can be for an unspecified period until all reserves are depleted. See Note 14 for a discussion of the synfuel plant.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents are primarily invested in two money market funds, which consist of highly liquid investments with maturities of 90 days or less at the date of purchase.

Trade Receivables

Trade accounts receivable are recorded at the invoiced amount and are non-interest bearing. We maintain a bad debt reserve based upon the expected collectibility of our accounts receivable. The reserve includes specific amounts for accounts that are likely to be uncollectible, as determined by such variables as customer creditworthiness, the age of the receivables, bankruptcies and disputed amounts. Account balances are charged off against the reserve after all means of collection have been exhausted and the potential for recovery is considered remote.

Inventories

Produced coal and supplies inventories generally are stated at the lower of average cost or net realizable value. Coal inventory costs include labor, supplies, equipment, operating overhead and other related costs. Purchased coal inventories are stated at the lower of cost, computed on the first-in, first-out method, or net realizable value.

Prior to 2006, we accounted for the costs of removing overburden and waste materials (stripping costs) incurred during the production phase of a mine as a component of surface mining inventory costs. As overburden was removed, the stripping costs were captured in inventory costs and attributed to the proven reserves benefited. On January 1, 2006, we adopted Emerging Issues Task Force ("EITF") Issue No. 04-6, "Accounting for Stripping Costs Incurred During Production in the Mining Industry" ("EITF 04-6"). This consensus limits accounting for production-related stripping costs as a component of inventory to those costs associated with extracted or saleable inventories. Therefore, stripping costs in 2007 and 2006 are recorded as Cost of produced coal revenue while 2005 stripping costs were shown in Inventories as Advance stripping costs.

Advance stripping costs

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

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

Income Taxes

We account for income taxes in accordance with Statement of Financial Accounting Standards ("SFAS") No. 109, "Accounting for Income Taxes" ("SFAS 109"), which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. SFAS 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including carrybacks, the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in the evaluation of our valuation allowance, we record a change in valuation allowance through income tax expense in the period such determination is made.

In June 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48") to create a single model to address accounting for uncertainty in income tax positions. FIN 48 clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. We adopted FIN 48 effective January 1, 2007. We accrue interest and penalties related to unrecognized tax benefits in Other noncurrent liabilities and recognize the related expense in Income tax expense.

Property, Plant and Equipment

Property, plant and equipment are carried at cost and stated net of accumulated depreciation. Expenditures that extend the useful lives of existing buildings and equipment are capitalized. Maintenance and repairs are expensed as incurred. Coal exploration costs are expensed as incurred. Costs incurred to maintain current production capacity at a mine and exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Development costs, including pre-production stripping costs, applicable to the opening of new coal mines and certain mine expansion projects are capitalized until production begins. When properties are retired or otherwise disposed, the related cost and accumulated depreciation are removed from the respective accounts and any profit or loss on disposition is credited or charged to Other revenue.

Our coal reserves are controlled either through direct ownership or through leasing arrangements. Mining properties owned in fee represent owned coal properties carried at cost. Leased mineral rights represent leased coal properties carried at the cost of acquiring those leases. The leases are generally long-term in nature (original term five to fifty years or until the mineable and merchantable coal reserves are exhausted), and substantially all of the leases contain provisions that allow for automatic extension of the lease term as long as mining continues.

Depreciation of buildings, plants and equipment is calculated on the straight-line method over their estimated useful lives or lease terms as follows:

	Years
Buildings and plants	20 to 30
Equipment	3 to 20
Capital leases	4 to 7

Ownership of assets under capital leases transfers to us at the end of the lease term. Depreciation of assets under capital leases is included within Depreciation, depletion and amortization.

Amortization of development costs is computed using the units-of-production method over the estimated proven and probable reserve tons.

Depletion of mining properties owned in fee and leased mineral rights is computed using the units-of-production method over the estimated proven and probable reserve tons (as adjusted for recoverability factors). As of December 31, 2007, approximately $65.8 million of costs associated with mining properties owned in fee and leased mineral rights is not currently subject to depletion as mining has not begun or production has been temporarily idled on the associated coal reserves.

We capitalize certain costs incurred in the development of internal-use software, including external direct material and service costs, in accordance with the American Institute of Certified Public Accountants' Statement of Position 98-1, "Accounting for the Costs of Computer Software Developed for or Obtained for Internal Use." All costs capitalized are amortized using the straight-line method over the estimated useful life not to exceed 7 years.

Impairment of Long-Lived Assets

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the assets is then reduced to their estimated fair value, which is usually measured based on an estimate of future discounted cash flows. There were no material impairment losses recorded during the periods covered by the consolidated financial statements.

Advance Mining Royalties

Coal leases that require minimum annual or advance payments and are recoverable from future production are generally deferred and charged to expense as the coal is subsequently produced. At December 31, 2007 and 2006, advance mining royalties included in Other noncurrent assets totaled $37.0 million and $35.1 million, net of an allowance of $16.2 million and $17.8 million, respectively.

Reclamation

We account for reclamation liabilities in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 requires that asset retirement obligations ("ARO") be recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows, in the period in which it is incurred. Management and engineers periodically review the estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed. In estimating future cash flows, we consider the estimated current cost of reclamation and apply inflation rates and a third party profit, as necessary. The third party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. When the liability is initially recorded, the offset is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Accretion expense is included in Cost of produced coal revenue. To settle the liability, the obligation is paid, and to the extent there is a difference between the liability and the amount of cash paid, a gain or loss upon settlement is incurred. Additionally, we perform a certain amount of required reclamation of disturbed acreage as an integral part of our normal mining process; these costs are expensed as incurred. See Note 9 for a more complete discussion of our reclamation liability.

Pension Plans

We sponsor a noncontributory defined benefit pension plan covering substantially all administrative and non-union employees. Our policy is to annually fund the defined benefit pension plan at or above the minimum amount required by law. We also sponsor a nonqualified supplemental benefit pension plan for certain salaried employees, which is unfunded.

We account for our defined benefit pension plans in accordance with SFAS No. 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" ("SFAS 158"). SFAS 158 requires us to recognize the funded status of our benefit plans in our Consolidated Balance Sheet and to recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. These amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost. We adopted SFAS 158 as of December 31, 2006. Prior to the adoption of SFAS 158, we accounted for our defined benefit pension plans in accordance with SFAS No. 87, "Employers' Accounting for Pension," which required the cost to provide benefits be accrued over the employees' estimated remaining service life. See Note 5 for a more complete discussion of our pension plans.

Workers' Compensation and Black Lung Benefits

We are liable for workers' compensation benefits for traumatic injuries under state workers' compensation laws in states in which we have operations. Our operations have workers' compensation coverage through a combination of either a self-insurance program, or commercial insurance through a deductible or first dollar insurance policy. We record our self-insured liability on a discounted actuarial basis using various assumptions, including discount rate and future cost trends.

We are also responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, and under various states' statutes for the payment of medical and disability benefits to employees and their dependents resulting from occurrences of black lung. We provide for federal and state black lung claims principally through a self-insurance program. Provisions for estimated benefits are determined on an actuarial basis. We use the service cost method to account for our self-insured black lung obligation. The liability measured under the service cost method represents the discounted future estimated cost for former employees either receiving or projected to receive benefits, and the portion of the projected liability relative to prior service for active employees projected to receive benefits. Expense for black lung under the service cost method represents the service cost, which is the portion of the present value of benefits allocated to the current year, interest on the accumulated benefit obligation, and amortization of unrecognized actuarial gains and losses. We amortize unrecognized actuarial gains and losses over a five-year period. See Note 11 for a more complete discussion of workers' compensation and black lung benefits.

Postretirement Benefits Other than Pensions

We sponsor defined benefit health care plans that provide postretirement medical benefits to eligible union and non-union members. Postretirement benefits other than pensions are accounted for in accordance with SFAS 158, which requires us to recognize the funded status of our benefit plans in our Consolidated Balance Sheet and to recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. These amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost. We adopted SFAS 158 as of December 31, 2006. Prior to the adoption of SFAS 158, we accounted for postretirement benefits other than pensions in accordance with SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," which required the cost to provide benefits be accrued over the employees' remaining service.

Under the Coal Industry Retiree Health Benefits Act of 1992 (the "Coal Act"), coal producers are required to fund medical and death benefits of certain retired union coal workers based on premiums assessed by the United Mine Workers of America ("UMWA") Benefit Funds. We treat our obligation under the Coal Act as participation in a multi-employer plan as permitted by EITF No. 92-13, "Accounting for Estimated Payments in Connection with the Coal Industry Retiree Health Benefit Act of 1992," and record the cost of our obligation as expense as payments are assessed. See Note 10 for a more complete discussion of postretirement benefits other than pensions.

Stock-based Compensation

Prior to 2006, we accounted for stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," ("APB No. 25") and related interpretations. On January 1, 2006, we adopted Financial Accounting Standards Board ("FASB") Statement No. 123(R), "Share-Based Payments" ("SFAS 123R") using the modified-prospective method. The modified-prospective method requires us to recognize compensation cost of equity instruments based on their grant-date fair value. Results from prior periods have not been restated. A cumulative effect of a change in accounting principle of $0.6 million loss (net of $0.4 million tax) was recognized in 2006 to reflect a change to the fair value method for those liability awards previously accounted for using the intrinsic value method and to reflect the impact of estimated forfeitures. We use the Black-Scholes option-pricing model to determine the fair value of stock options as of the date of grant and certain liability awards with option characteristics (i.e., stock appreciation rights, or "SARs"). For periods after the adoption date, compensation cost for both equity and liability awards have been measured and recorded in accordance with the provisions of SFAS 123R. The benefits of tax deductions in excess of recognized compensation cost are reported as a financing cash flow, rather than as an operating cash flow as required under previous literature. See Note 12 for a more complete discussion of stock-based compensation.

Earnings per Share

The number of shares used to calculate basic earnings (loss) per share is based on the weighted average number of our outstanding common shares during the respective periods. The number of shares used to calculate diluted earnings (loss) per share is based on the number of common shares used to calculate basic earnings (loss) per share plus the dilutive effect of stock options and other stock-based instruments held by our employees and directors during each period and debt securities currently convertible into our common stock, $0.625 par value ("Common Stock") during the period. In accordance with accounting principles generally accepted in the United States, the effect of dilutive securities in the amount of 0.8 million, 2.0 million and 13.0 million for the years ended December 31, 2007, 2006 and 2005, respectively, was excluded from the calculation of the diluted earnings (loss) per common share as such inclusion would result in antidilution.

The computation for basic and diluted earnings (loss) per share is based on the following per share information:

	Year Ended		
	December 31, 2007	December 31, 2006	December 31, 2005
	(In Thousands, Except Per Share Amounts)		
Numerator:			
Income (Loss) before cumulative effect of accounting change - numerator for basic	$ 94,098	$ 41,616	$ (101,638)
Cumulative effect of accounting change, net of tax	-	(639)	-
Effect of convertible notes	200	-	-
Net income (loss) - numerator for diluted	$ 94,298	$ 40,977	$ (101,638)
Denominator:			
Weighted average shares - denominator for basic	80,123	80,847	76,390
Effect of stock options/restricted stock	207	539	-
Effect of convertible notes	324	-	-
Adjusted weighted average shares - denominator for diluted	80,654	81,386	76,390
Income (Loss) per share:			
Basic:			
Before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)
Cumulative effect of accounting change	-	(0.01)	-
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)
Diluted:			
Before cumulative effect of accounting change	$ 1.17	$ 0.51	$ (1.33)
Cumulative effect of accounting change	-	(0.01)	-
Net income (loss)	$ 1.17	$ 0.50	$ (1.33)

Accounting Pronouncements

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS 157"). SFAS 157 defines fair value, establishes a framework for measuring fair value in accounting principles generally accepted in the United States, and expands disclosures about fair value measurement. It does not require any new fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years for financial assets and liabilities, and for fiscal years beginning after November 15, 2008 for nonfinancial assets and liabilities. We are currently assessing the potential impact of the statement on our financial position and results of operations.

2. Inventories

Inventories consisted of the following:

	December 31, 2007	December 31, 2006
	(In Thousands)	
Saleable coal	$ 120,343	$ 124,816
Raw coal	11,471	13,210
Subtotal coal inventory	131,814	138,026
Supplies inventory	51,546	53,030
Total inventory	$ 183,360	$ 191,056

Saleable coal represents coal ready for sale, including inventories designated for customer facilities under consignment arrangements of $62.1 million and $61.0 million at December 31, 2007 and 2006, respectively. Raw coal represents coal that generally requires further processing prior to shipment to the customer.

3. Other Current Assets

Other current assets are comprised of the following:

	December 31, 2007	December 31, 2006
	(In Thousands)	
Longwall panel costs	$ 18,029	$ 38,843
Deposits	118,944	106,833
Other	28,967	26,646
Total other current assets	$ 165,940	$ 172,322

Deposits consist primarily of funds placed in restricted accounts with financial institutions to collateralize letters of credit that support workers' compensation requirements, insurance and other obligations. Deposits at December 31, 2007 included $96.0 million of funds pledged as collateral to support $45.1 million of outstanding letters of credit and a $50.0 million appeal bond. In addition, there were $13.0 million of United States Treasury securities supporting various regulatory obligations. Deposits at December 31, 2006 included $105.1 million of funds pledged as collateral to support $100.1 million of outstanding letters of credit (see Note 6 for further discussion).

4. Property, Plant and Equipment

Property, plant and equipment is comprised of the following:

	December 31, 2007	December 31, 2006
	(In Thousands)	
Land, buildings and equipment	$ 2,082,003	$ 2,005,029
Mining properties owned in fee and leased mineral rights	704,547	690,687
Mine development	863,303	781,834
Total property, plant and equipment	3,649,853	3,477,550
Less accumulated depreciation, depletion and amortization	(1,855,933)	(1,700,769)
Net property, plant and equipment	$ 1,793,920	$ 1,776,781

Land, buildings and equipment includes gross assets under capital leases of $17.3 million and $32.3 million at December 31, 2007 and 2006, respectively.

During the second quarter of 2007, we exchanged coal reserves with a third party, recognizing a gain in Other revenue of $10.3 million (pre-tax) in accordance with Statement of Financial Accounting Standards ("SFAS") No 153, "Exchanges of Nonmonetary Assets, an Amendment of APB No. 29, Accounting for Nonmonetary Transactions." The gain included a $1.0 million cash payment. The acquired coal reserves were recorded in Property, plant and equipment at the fair value of the reserves surrendered, less the $1.0 million payment received.

During the third quarter of 2006, we sold our Falcon reserves, located in Boone County, West Virginia, to a privately held coal company for total consideration of $30.8 million in cash. The sale consisted of approximately 5.5 million tons of coal reserves. The total gain recognized in accordance with SFAS 153 on the sale was $30.0 million (pre-tax), which is included within Other revenue for 2006.

During 2007 and 2006, we sold and leased-back certain mining equipment in several transactions for net proceeds of $13.1 million and $21.8 million, respectively. See Note 13 for further details.

5. Pension Plans

Defined Benefit Pension Plans

We sponsor a qualified non-contributory defined benefit pension plan, which covers substantially all administrative and non-union employees. Based on a participant's entrance date to the plan, the participant may accrue benefits based on one of four benefit formulas. Two of the formulas provide pension benefits based on the employee's years of service and average annual compensation during the highest five consecutive years of service. The third formula credits certain eligible employees with flat dollar contributions based on years of service with Massey and years of service under the UMWA 1974 Pension Plan. The fourth formula provides benefits under a cash balance formula with contribution credits based on hours worked. This last formula has a guaranteed rate of return on contributions of 4% for all contributions after December 31, 2003. Funding for the plan is generally at the minimum contribution level required by applicable regulations. We made voluntary contributions of $0.4 million and $18.1 million to the qualified plan during 2007 and 2006, respectively.

An independent trustee holds the plan assets for the qualified defined benefit pension plan. The plan's assets include cash and cash equivalents, corporate and government bonds, preferred and common stocks and an investment in a group annuity contract. There were no investments in Common Stock held by the plan at December 31, 2007 or 2006. We have an internal investment committee ("Investment Committee") that sets investment policy, selects and monitors investment managers and monitors asset allocation. Diversification of assets is employed to reduce risk. The target asset allocation is 65% for equity securities (including 50% domestic and 15% international) and 35% for cash and interest bearing securities. The investment policy is based on the assumption that the overall portfolio volatility will be similar to that of the target allocation. Given the volatility of the capital markets, strategic adjustments in various asset classes may be required to rebalance asset allocation back to its target policy. Investment fund managers are not permitted to invest in certain securities and transactions as outlined by the investment policy statements specific to each investment category without prior Investment Committee approval.

To develop the expected long-term rate of return on assets assumption, we considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio. This resulted in the selection of the 8.0% long-term rate of return on assets assumption for the year ended December 31, 2007.

The fair value of the major categories of qualified defined benefit pension plan assets includes the following:

	December 31, 2007		December 31, 2006	
	(Dollars In Thousands)			
Equity securities (domestic and international)	$ 187,439	64.2%	$ 186,695	65.4%
Debt securities	72,417	24.8%	77,902	27.3%
Other (includes cash, cash equivalents and a group annuity contract)	31,891	11.0%	20,822	7.3%
Total fair value of plan assets	$ 291,747	100.0%	$ 285,419	100.0%

In addition to the qualified defined benefit pension plan noted above, we sponsor a nonqualified supplemental benefit pension plan for certain salaried employees. Participants in this nonqualified supplemental benefit pension plan accrue benefits under the same formula as the qualified defined benefit pension plan, however, where the benefit is capped by Internal Revenue Service ("IRS") limitations, this nonqualified supplemental benefit pension plan compensates for benefits in excess of the IRS limit. This supplemental benefit pension plan is unfunded, with benefit payments made by us.

The following table sets forth the change in benefit obligation, plan assets and funded status of both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan:

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(In Thousands)	
Change in benefit obligation:		
Benefit obligation at the beginning of the period	$ 256,925	$ 242,400
Service cost	9,716	9,230
Interest cost	15,023	13,922
Actuarial (gain) loss	(18,796)	957
Benefits paid	(10,631)	(9,584)
Benefit obligation at the end of the period	252,237	256,925
Change in plan assets:		
Fair value at the beginning of the period	285,419	246,992
Actual return on assets	16,512	29,873
Company contributions	447	18,138
Benefits paid	(10,631)	(9,584)
Fair value of plan assets at end of period	291,747	285,419
Funded status	$ 39,510	$ 28,494
Qualified defined benefit pension plan, included in Pension assets	$ 47,323	$ 34,974
Nonqualified supplemental benefit pension plan, included in Other noncurrent liabilities	(7,813)	(6,480)
Accrued pension assets recognized (net)	$ 39,510	$ 28,494

The nonqualified supplemental benefit pension plan had an accumulated benefit obligation of $7.2 million and $6.3 million as of December 31, 2007 and 2006, respectively.

As discussed in Note 1, we adopted SFAS 158 on December 31, 2006. As a result of adoption, we recognized the funded status of the qualified defined benefit pension plan and the nonqualified supplemental benefit pension plan in the Consolidated Balance Sheet, decreasing the Pension asset by $53.2 million for the qualified defined benefit pension plan and increasing Other noncurrent liabilities by $199,000 for the nonqualified supplemental benefit pension plan. The $53.4 million, net of the deferred tax effect of $20.8 million, was recorded in Accumulated other comprehensive loss.

The table below details the changes to Accumulated other comprehensive loss related to defined benefit pension plans in accordance with SFAS 158:

	2007		2006	
	(In Thousands)			
	Net loss	Prior service cost	Net loss	Prior service cost
January 1 beginning balance	32,821	84	-	-
Changes to Accumulated other comprehensive loss	(10,339)	(24)	32,821	84
December 31 ending balance	$ 22,482	$ 60	$ 32,821	$ 84

We expect to recognize $41,545 of prior service cost and $1.0 million of net loss in 2008.

The assumptions used in determining pension benefit obligations for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan are as follows:

	December 31, 2007	December 31, 2006
Discount rates	6.50%	5.90%
Rates of increase in compensation levels	4.00%	4.00%

Net periodic pension expense for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan includes the following components:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In Thousands)	
Service cost	$ 9,716	$ 9,230	$ 9,324
Interest cost	15,023	13,922	12,864
Expected return on plan assets	(22,427)	(19,952)	(17,737)
Recognized loss	4,068	6,226	3,607
Amortization of prior service cost	39	39	40
Net periodic pension expense	$ 6,419	$ 9,465	$ 8,098

The assumptions used in determining pension expense for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan are as follows:

	December 31, 2007	December 31, 2006	December 31, 2005
Discount rates	5.90%	5.75%	5.75%
Rates of increase in compensation levels	4.00%	4.00%	4.00%
Expected long-term rate of return on plan assets	8.00%	8.00%	8.00%

We do not expect that any contributions will be required in 2008 for the qualified defined benefit pension plan. We expect to voluntarily contribute approximately $200,000 for benefit payments to participants in 2008 for the nonqualified supplemental benefit pension plan.

The following benefit payments from both the qualified defined benefit pension plan and the nonqualified supplemental benefit pension plan, which reflect expected future service, as appropriate, are expected to be paid from the plans:

	Expected Pension Benefit Payments
	(In Thousands)
2008	$ 11,635
2009	12,424
2010	13,049
2011	13,764
2012	14,665
Years 2013 to 2017	87,977

Multi-Employer Pension

Under labor contracts with the UMWA, certain operations make payments into two multi-employer defined benefit pension plan trusts established for the benefit of certain union employees. The contributions are based on tons of coal produced and hours worked. Such payments aggregated less than $400,000 in the year ended December 31, 2007 and less than $100,000 in each of the years ended December 31, 2006 and 2005.

Defined Contribution Plan

We currently sponsor a defined contribution pension plan for certain union employees. The plan is non-contributory and our contributions are based on hours worked. Contributions to this plan were approximately $50,000 for the year ended December 31, 2007 and $100,000 for each of the years ended December 31, 2006 and 2005.

Salary Deferral and Profit Sharing (401(K)) Plan

We also sponsor a salary deferral and profit sharing plan covering substantially all administrative and non-union employees. The maximum salary deferral rate is 75% of eligible pay, subject to IRS limitations. We contribute a fixed match on employee contributions on up to 10% of eligible pay. Our contributions aggregated approximately $3.6 million, $3.9 million and $3.7 million for the years ended December 31, 2007, 2006 and 2005, respectively.

6. Debt

Our debt is comprised of the following:

	December 31, 2007	December 31, 2006
	(In Thousands)	
6.875% senior notes due 2013, net of discount	$ 755,401	$ 754,804
6.625% senior notes due 2010	335,000	335,000
2.25% convertible senior notes due 2024	9,647	9,647
4.75% convertible senior notes due 2023	730	730
Capital lease obligations	8,823	11,232
Fair value hedge adjustment	(5,054)	(6,506)
Total debt	1,104,547	1,104,907
Amounts due within one year	(1,875)	(2,583)
Total long-term debt	$ 1,102,672	$ 1,102,324

The weighted average effective interest rate of the outstanding borrowings was 7.0% at December 31, 2007 and 2006. At December 31, 2007, our available liquidity was $479.3 million, including $365.2 million of cash and cash equivalents and $114.1 million availability on our asset-based revolving credit facility.

Refinancing Transactions

On November 22, 2005, we commenced a cash tender offer for any and all of the outstanding $220.1 million of 6.95% senior notes due 2007 (the "6.95% Notes"), a cash tender offer for any and all of the outstanding $132.0 million of 4.75% Notes and an exchange offer for any and all of our outstanding $175.0 million of 2.25% Notes.

On December 9, 2005, we commenced a private offering of the 6.875% Notes and announced our intention to use the proceeds of the offering to purchase the 6.95% Notes in connection with the 6.95% Notes tender offer, the redemption of any of the 6.95% Notes that were not tendered in the 6.95% Notes tender offer, the purchase of the 4.75% Notes in connection with the 4.75% Notes tender offer, the cash payment related to the exchange offer for the 2.25% Notes and for general corporate purposes.

On December 21, 2005, we settled with holders of $189.5 million of the $220.1 million outstanding of the 6.95% Notes, representing approximately 86.0% of the outstanding 6.95% Notes, who tendered their 6.95% Notes. On December 27, 2005, we redeemed the remaining $30.6 million of the 6.95% Notes.

On December 28, 2005, we accepted tender of 4.75% Notes from holders of $131.3 million, or 99.4%, of the outstanding 4.75% Notes.

On December 28, 2005, under the terms of the 2.25% Notes exchange offer, we exchanged shares of Common Stock and a cash payment for $165.4 million, or 94.5%, of the outstanding 2.25% Notes tendered by the holders.

We recognized charges totaling $219.0 million (pre-tax), including $6.6 million (pre-tax) for the write-off of unamortized financing fees, for the debt repurchase and exchange offer as of December 31, 2005.

6.875% Notes

The 6.875% Notes are unsecured obligations ranking equally with all other unsecured senior indebtedness of ours and are guaranteed by substantially all of our current and future subsidiaries. Interest on the 6.875% Notes is payable on December 15 and June 15 of each year. We may redeem the 6.875% Notes, in whole or in part, for cash at any time on or after December 15, 2009 at a redemption price equal to 100% of the principal amount plus a premium declining ratably to par, plus accrued and unpaid interest. At any time on or before December 15, 2008, we may redeem up to 35% of the principal amount of the 6.875% Notes with the proceeds of qualified equity offerings at a redemption price of 106.875% of the principal amount, plus accrued and unpaid interest. The 6.875% Notes are guaranteed by A.T. Massey and substantially all of our current and future operating subsidiaries (the "Guarantors"). The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 6.875% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X).

The 6.875% Notes contain a number of significant restrictions and covenants that limit our ability and our subsidiaries' ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) restrict distributions from subsidiaries. We are currently in compliance with all covenants.

6.625% Notes

The 6.625% senior notes due 2010 are unsecured obligations of ours and rank equally with all other unsecured senior indebtedness. Interest is payable semiannually on May 15 and November 15 of each year. We may redeem the 6.625% Notes, in whole or in part, at any time on or after November 15, 2007 at a redemption price equal to 100% of the principal amount plus a premium declining ratably to par, plus accrued and unpaid interest. The 6.625% Notes are guaranteed by the Guarantors. The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 6.625% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X).

The 6.625% Notes contain a number of significant restrictions and covenants that limit our ability and our subsidiaries' ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) restrict distributions from subsidiaries. We are currently in compliance with all covenants.

2.25% Notes

The 2.25% convertible senior notes due 2024 are unsecured obligations of ours, rank equally with all other unsecured senior indebtedness and are guaranteed by the Guarantors. Interest is payable semiannually on April 1 and October 1 of each year. We registered the 2.25% Notes with the SEC for resale.

Holders of the 2.25% Notes may require us to purchase all or a portion of their notes for cash on April 1, 2011, 2014, and 2019, at a purchase price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest. In addition, if we experience certain specified types of fundamental changes on or before April 1, 2011, the holders may require us to purchase the notes for cash. We may redeem all or a portion of the 2.25% Notes for cash at any time on or after April 6, 2011, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest.

The 2.25% Notes are convertible during certain periods by holders into shares of Common Stock initially at a conversion rate of 29.7619 shares of Common Stock per $1,000 principal amount of 2.25% Notes (subject to adjustment upon certain events) under the following circumstances: (i) if the price of Common Stock issuable upon conversion reaches specified thresholds; (ii) if we redeem the 2.25% Notes; (iii) upon the occurrence of certain specified corporate transactions; or (iv) if the credit ratings assigned to the 2.25% Notes decline below certain specified levels. Regarding the thresholds in (i) above, holders may convert each of their notes into shares of Common Stock during any calendar quarter (and only during such calendar quarter) if the last reported sale price of Common Stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% of the conversion price per share of Common Stock. The conversion price is $33.60 per share. None of the 2.25% Notes are currently eligible for conversion. As of December 31, 2007, if all of the notes outstanding were eligible and were converted, we would have needed to issue 287,113 shares of Common Stock.

4.75% Notes

The 4.75% convertible senior notes due 2023 are unsecured obligations of ours, rank equally with all other unsecured senior indebtedness and are guaranteed by our wholly owned subsidiary, A.T. Massey, which together with our subsidiaries accounts for substantially all of our assets and all of our revenues. Interest is payable semiannually on May 15 and November 15 of each year. We registered the 4.75% Notes with the SEC for resale.

We may be required by the holders of the 4.75% Notes to purchase all or a portion of their notes on May 15, 2009, 2013, and 2018. For purchases on May 15, 2009, we must pay cash for all 4.75% Notes so purchased. For purchases on May 15, 2013 or 2018, we may, at our option, choose to pay the purchase price for such 4.75% Notes in cash, in shares of Common Stock or any combination thereof. We may redeem some or all of the 4.75% Notes at any time on or after May 20, 2009, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest.

The 4.75% Notes are convertible during certain periods by holders into shares of Common Stock initially at a conversion rate of 51.573 shares of Common Stock per $1,000 principal amount of 4.75% Notes (subject to adjustment upon certain events) under the following circumstances: (i) if the price of Common Stock issuable upon conversion reaches specified thresholds; (ii) if we redeem the 4.75% Notes; (iii) upon the occurrence of certain specified corporate transactions; or (iv) if the credit ratings assigned to the 4.75% Notes decline below specified levels. Regarding the thresholds in (i) above, holders may convert each of their notes into shares of Common Stock during any calendar quarter (and only during such calendar quarter) if the last reported sale price of Common Stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% of the conversion price per share of Common Stock. The conversion price is $19.39 per share.

As of December 31, 2007, the price of Common Stock had reached the specified threshold for conversion. Consequently, the 4.75% Notes are convertible until March 31, 2008, the last day of our first quarter. The 4.75% Notes may be convertible beyond this date if the specified threshold for conversion is met in subsequent quarters. As of December 31, 2007, if all of the notes outstanding were eligible and were converted, we would have needed to issue 37,649 shares of Common Stock.

Fair Value Hedge Adjustment

On November 10, 2003, we entered into a fixed interest rate to floating interest rate swap agreement (the "Swap Agreement") covering a notional amount of debt of $240 million. We designated this swap as a fair value hedge of a portion of our 6.625% Notes. We used the Swap Agreement to reduce interest expense and modify exposure to interest rate risk by converting our fixed rate debt to a floating rate liability. The Swap Agreement was originally scheduled to terminate on November 15, 2010, however, on December 9, 2005, we notified the swap counterparty that we were exercising our right to terminate the Swap Agreement because of anticipated increases in the variable interest rate component of the swap. We paid a $7.9 million termination payment to the swap counterparty on December 13, 2005. The termination payment, which is reflected in the table above as Fair value hedge adjustment, will be amortized into Interest expense through November 15, 2010.

Asset-Based Lending Arrangement

On August 15, 2006, we entered into an amended and restated asset-based revolving credit facility, which provides for available borrowings, including letters of credit of up to $175 million, depending on the level of eligible inventory and accounts receivables. As of December 31, 2007, this facility supported $60.9 million of letters of credit and there were no outstanding borrowings under this facility. Any future borrowings under this facility will be variable rate borrowings, based on the applicable LIBOR rate for the specified rate reset period, plus an applicable margin. As of December 31, 2007, the applicable margin to LIBOR was 125 basis points.

The facility is secured by our accounts receivable, eligible coal inventories located at our facilities and on consignment at customers' facilities, and other intangibles. At December 31, 2007, total remaining availability was $114.1 million based on qualifying inventory and accounts receivable. The credit facility expires in August 2011.

This facility contains a number of significant restrictions and covenants that limit our ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) make distributions from subsidiaries. We are currently in compliance with all covenants.

Debt Maturity

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

	(In Thousands)
2008	$ 1,875
2009	1,967
2010	337,218
2011	2,670
2012	13
Beyond 2012*	770,457

* The 4.75% Notes and the 2.25% Notes in the amounts of $0.7 million and $9.6 million, respectively, included herein may be redeemed at the option of the holders in 2009 and 2011, respectively.

Total interest paid for the years ended December 31, 2007, 2006 and 2005, was $75.7 million, $75.0 million and $56.1 million, respectively.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements including guarantees, operating leases, indemnifications, and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in the consolidated balance sheets, and, except for the operating leases, which are discussed in Note 13 to the Notes to Consolidated Financial Statements, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

From time to time we use bank letters of credit to secure our obligations for worker's compensation programs, various insurance contracts and other obligations. At December 31, 2007, we had $106.0 million of letters of credit outstanding of which $45.1 million was collateralized by $46.0 million of cash deposited in restricted, interest bearing accounts pledged to issuing banks and $60.9 million was issued under our asset based lending arrangement. No claims were outstanding against those letters of credit as of December 31, 2007.

On January 22, 2008, a settlement was reached regarding our previously reported disagreement and protest of a new actuarial methodology being applied by the Office of Workers' Claims ("OWC") for the Commonwealth of Kentucky in determining levels of surety against potential future claims. The settlement resulted in the dismissal of our cases pending in the Franklin County Circuit Court of Kentucky and required us to post additional surety of $11.5 million for the 2006 and 2007 assessments against potential claims. That additional surety requirement was satisfied with the posting of a letter of credit issued under our asset-based lending arrangement.

We use surety bonds to secure reclamation, workers' compensation, wage payments, and other miscellaneous obligations. As of December 31, 2007, we had $364.1 million of outstanding surety bonds. These bonds were in place to secure obligations as follows: post-mining reclamation bonds of $304.7 million, an appeal bond of $50.0 million, and other miscellaneous obligation bonds of $9.4 million. Outstanding surety bonds of $46.1 million are secured with letters of credit. In addition, in October 2007, we deposited $50.0 million into an interest bearing account which is pledged to an insurance company that issued the $50.0 million appeal bond in the Wheeling-Pitt legal matter (see Note 17 to Notes to Consolidated Financial Statements for additional details). The $50 million is reported in Deposits within Other current assets.

Generally, the availability and market terms of surety bonds continue to be challenging. If we are unable to meet certain financial tests applicable to some of our surety bonds, or to the extent that surety bonds otherwise become unavailable, we would need to replace the surety bonds or seek to secure them with letters of credit, cash deposits, or other suitable forms of collateral.

7. Income Taxes

Income tax expense included in the Consolidated Statements of Income is as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In Thousands)	
Current:			
Federal	$ 7,876	$ 20,694	$ 2,852
State and local	126	95	117
Total current	8,002	20,789	2,969
Deferred:			
Federal	24,593	(15,439)	21,773
State and local	2,810	(1,942)	1,486
Total deferred	27,403	(17,381)	23,259
Income tax expense	$ 35,405	$ 3,408	$ 26,228

A reconciliation of Income tax expense calculated at the federal statutory rate of 35% to our Income tax expense on Net income is as follows:

	Year Ended		
	December 31, 2007	December 31, 2006	December 31, 2005
	(In Thousands)		
U.S. statutory federal tax expense (benefit)	$ 45,326	$ 15,758	$ (26,394)
Increase (Decrease) resulting from:			
State taxes	(116)	(2,393)	1,322
Non-deductible penalties	8,062	852	546
Percentage depletion	(33,501)	(25,897)	(29,932)
Non-deductible compensation	711	1,279	9,653
Non-deductible refinancing and exchange offer costs	(4,809)	-	71,737
Extraterritorial excluded income	-	(797)	(1,160)
Valuation allowance adjustment	31,343	16,066	5,309
Uncertain tax positions	(2,325)	(1,197)	(4,284)
Refund from settlement of 2001 IRS audit	(4,609)	-	-
Other, net	(4,677)	(263)	(569)
Income tax expense	$ 35,405	$ 3,408	$ 26,228

Deferred taxes reflect the tax effects of differences between the amounts recorded as assets and liabilities for financial reporting purposes and the amounts recorded for income tax purposes. The tax effects of temporary differences giving rise to deferred tax assets and liabilities are as follows:

	Year Ended	
	December 31, 2007	December 31, 2006
	(In Thousands)	
Deferred tax assets:		
Postretirement benefit obligations	$ 66,235	$ 68,555
Workers' compensation	22,588	21,456
Reclamation and mine closure	47,281	51,440
Alternative minimum tax credit carryforwards	119,651	135,103
Accounting change on post-production stripping costs	-	59,970
Litigation	10,247	18,103
Deferred compensation	24,660	17,812
Federal net operating loss	98,434	21,892
State net operating loss	28,194	30,682
Other	27,483	9,708
Total deferred tax assets	444,773	434,721
Valuation allowance for deferred tax assets	(194,122)	(163,656)
Total deferred tax assets, net of valuation allowance	250,651	271,065
Deferred tax liabilities:		
Plant, equipment and mine development	(275,362)	(270,693)
Mining property and mineral rights	(117,609)	(107,267)
Deferred royalties	(10,339)	(9,642)
Other	(2,046)	(153)
Total deferred tax liablities	(405,356)	(387,755)
Deferred income taxes	$ (154,705)	$ (116,690)

Deferred tax assets include alternative minimum tax ("AMT") credits of $119.7 million and $135.1 million at December 31, 2007 and 2006, respectively, federal net operating loss carryforwards of $281.2 million and $63.2 million as of December 31, 2007 and 2006, respectively, and net state net operating loss ("NOL") carryforwards of $704.8 million and $767.0 million as of December 31, 2007 and 2006, respectively. The AMT credits have no expiration date. Federal NOL carryforwards expire beginning in 2018 and ending in 2020. State NOL carryforwards expire beginning in 2008 and ending in 2020. The NOL carryforwards available at December 31, 2007 increased over the amount available at the end of the prior year primarily due to (i) adjustments related to disallowed ten-year carryback claims that will be made based on an IRS audit of the December 31, 2003 and 2004 tax years and (ii) an expected IRS approval of a tax method accounting change related to the tax deductibility of advanced stripping costs.

We have recorded a valuation allowance for a portion of deferred tax assets that management believes, more likely than not, will not be realized. These deferred tax assets include AMT credits, federal NOL and state NOL carryforwards that will likely not be realized at the maximum effective tax rate. The valuation allowance increased for the year ended December 31, 2007 primarily as a result of the increase in federal NOL carryforwards discussed above.

In June 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48") to create a single model to address accounting for uncertainty in income tax positions. FIN 48 clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. We increased Retained earnings by $5.2 million for the cumulative effect of adoption of FIN 48 as of January 1, 2007. We accrue interest and penalties related to unrecognized tax benefits in Other noncurrent liabilities and recognize the related expense in Income tax expense. No payments for interest and penalties are included in Income tax expense for 2007 and we accrued $3.1 million for the payment of interest during December 31, 2007.

The following table reconciles the total amounts of unrecognized tax benefits from January 1, 2007 to December 31, 2007:

	(In Thousands)
Balance at January 1, 2007	$ 2,325
Additions based on tax positions related to the current year	-
Additions for tax positions of prior years	49,130
Reductions for tax positions of prior years	(2,325)
Settlements	(49,130)
Reductions due to lapse of applicable statute of limitations	-
Balance at December 31, 2007	$ -

The above table reflects unrecognized tax benefits identified in 2007 related to the disallowed ten-year carryback claims discussed above and agreed to with the IRS prior to yearend.

Prior to the adoption of FIN 48, we followed a methodology of establishing reserves for tax contingencies when, despite the belief that our tax return positions were fully supported, certain positions were likely to be challenged and might not be fully sustained. We establish the reserves based upon management's assessment of exposure associated with permanent tax differences (i.e., tax depletion expense), tax credits and interest expense applied to temporary difference adjustments. The tax reserves were analyzed at least annually and adjustments were made based upon changes in facts and circumstances, such as the progress of federal and state audits, case law and emerging legislation. During 2006, we reduced our tax reserve by $1.2 million, reflecting the reduction in exposure due to the notification of no exceptions from the IRS of a prior statutory period, partially offset by additional exposures identified for that tax year. Payments for federal taxes and state taxes of $63,000 were applied against the reserve during the year ended December 31, 2006, as a result of audits of prior periods. During 2005, we reduced our tax reserve by $4.3 million, reflecting the reduction in exposure due to the closing of prior period audits by state taxing authorities and the closing of a federal statutory period, partially offset by additional exposures identified for the 2005 tax year.

We file income tax returns in the United States federal and various state jurisdictions, including West Virginia, Kentucky and Virginia. The Internal Revenue Service ("IRS") has examined our federal income tax returns, or statutes of limitations have expired for years through 2000. Additionally, the IRS has sent notification to us of no change for our calendar year ended December 31, 2002 tax return. We are currently under audit from the IRS for the calendar years ended December 31, 2003 and 2004. In the various states where we file state income tax returns, the state tax authorities have examined our state returns, or statutes of limitations have expired through 2001. Management believes that we have adequately provided for any income taxes and interest and penalties that may ultimately be paid with respect to all open tax years. All unrecognized tax benefits would affect the effective tax rate if we were to recognize them. We anticipate a payment during 2008 of the entire current interest accrued for uncertain tax positions, due to the anticipated settlement of the 2003-2004 IRS audit.

8. Other Noncurrent Liabilities

Other noncurrent liabilities are comprised of the following:

	December 31, 2007	December 31, 2006
	(In Thousands)	
Reclamation (Note 9)	$ 142,213	$ 142,687
Other postretirement benefits (Note 10)	141,087	138,109
Workers' compensation and black lung (Note 11)	90,702	89,227
Other	77,426	99,831
Total other noncurrent liabilities	$ 451,428	$ 469,854

9. Reclamation

Our reclamation liabilities primarily consist of spending estimates related to reclaiming surface land and support facilities at both surface and underground mines in accordance with federal and state reclamation laws as defined by each mine permit. The obligation and corresponding asset are recognized in the period in which the liability is incurred.

We estimate our ultimate reclamation liability based upon detailed engineering calculations of the amount and timing of the future cash flows to perform the required work. We consider the estimated current cost of reclamation and apply inflation rates and a third party profit, as necessary. The third party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The discount rate applied is based on the rates of treasury bonds with maturities similar to the estimated future cash flow, adjusted for our credit standing.

The following table describes all changes to our reclamation liability:

	Year Ended	
	December 31, 2007	December 31, 2006
	(In Thousands)	
Reclamation liability at beginning of period	$ 171,954	$ 156,776
Accretion expense	11,758	10,166
Liability assumed/incurred	2,168	3,627
Liability disposed	(142)	-
Revisions in estimated cash flows	(6,036)	5,590
Payments	(11,061)	(4,205)
Reclamation liability at end of period	168,641	171,954
Less amount included in Other current liabilities	26,428	29,267
Total reclamation, included in Other noncurrent liabilities	$ 142,213	$ 142,687

10. Other Postretirement Benefits

We sponsor defined benefit health care plans that provide postretirement medical benefits to eligible union and non-union employees. To be eligible, retirees must meet certain age and service requirements. Depending on year of retirement, benefits may be subject to annual deductibles, coinsurance requirements, lifetime limits and retiree contributions. Service costs are accrued currently based on an annual study prepared by independent actuaries. These plans are unfunded.

Net periodic postretirement benefit cost includes the following components:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In Thousands)	
Service cost	$ 3,668	$ 3,758	$ 3,607
Interest cost	8,467	7,959	6,926
Amortization of net loss	1,864	2,307	1,704
Amortization of prior service credit	(750)	(750)	(2,651)
Net periodic postretirement benefit cost	$ 13,249	$ 13,274	$ 9,586

The discount rate assumed to determine the net periodic postretirement benefit cost was 5.90% for the year ended December 31, 2007 and 5.75% for each of the years ended December 31, 2006 and 2005, respectively.

The following table sets forth the change in benefit obligation of our postretirement benefit plans:

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(In Thousands)	
Change in benefit obligation:		
Benefit obligation at the beginning of the period	$ 144,325	$ 135,999
Service cost	3,668	3,758
Interest cost	8,467	7,959
Actuarial (gain)/loss	(3,546)	1,985
Benefits paid	(5,181)	(5,376)
Benefit obligation at the end of the period	$ 147,733	$ 144,325
Accrued postretirement benefit obligation	$ 147,733	$ 144,325
Amount included in Payroll and employee benefits	6,646	6,216
Postretirement benefit obligation, included in Other noncurrent liabilities	$ 141,087	$ 138,109

As discussed in Note 1, we adopted SFAS 158 on December 31, 2006. According to the adoption provisions, we recognized the funded status of the postretirement medical benefit plans in the Consolidated Balance Sheet, increasing Other noncurrent liabilities by $29.4 million. The $29.4 million, net of the deferred tax effect of $11.5 million, was recorded in Accumulated other comprehensive loss.

The table below details the changes to Accumulated other comprehensive loss related to defined benefit pension plans in accordance with SFAS 158:

	2007 Net loss	2007 Prior service credit	2006 Net loss	2006 Prior service credit
	(In Thousands)			
January 1 beginning balance	$ 23,434	$ (5,521)	$ -	$ -
Changes to Accumulated other comprehensive loss	(3,302)	458	23,434	(5,521)
December 31 ending balance	$ 20,132	$ (5,063)	$ 23,434	$ (5,521)

We expect to recognize $0.8 million of prior service credit and $1.3 million of net actuarial loss in 2008.

The discount rates used to determine the benefit obligations were 6.50% and 5.90% for the years ended December 31, 2007 and 2006 respectively.

The assumed health care cost trend rates used to determine the benefit obligation as of the end of each year are as follows:

	December 31, 2007	December 31, 2006
Health care cost trend rate for next year	8.50%	8.20%
Ultimate trend rate	5.00%	5.00%
Year that the rate reaches ultimate trend rate	2013	2011

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

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In Thousands)	
Effect on total of service and interest costs components	$ 1,997	$ (1,609)
Effect on accumulated postretirement benefit obligation	$ 21,497	$ (17,661)

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid in the periods noted:

	Expected Benefit Payments
	(In Thousands)
2008	$ 6,889
2009	7,589
2010	8,231
2011	8,969
2012	9,504
Years 2013 to 2017	52,371

Multi-Employer Benefits

Under the Coal Act, coal producers are required to fund medical and death benefits of certain retired union coal workers based on premiums assessed by the UMWA Benefit Funds. Based on available information at December 31, 2007, our obligation under the Coal Act was estimated at approximately $19.8 million, compared to our estimated obligation at December 31, 2006 of $24.1 million. The obligation was discounted using a 5.00% rate each year. We treat our obligation under the Coal Act as participation in a multi-employer plan and record the cost of our obligation as expense as payments are assessed. The expense related to this obligation for the years ended December 31, 2007, 2006 and 2005 totaled $1.3 million, $4.3 million and $4.8 million, respectively. The $1.3 million expense in 2007 was net of a $1.6 million refund from the UMWA Combined Benefit Fund ("CBF"). The refund was a result of the Tax Relief and Retiree Health Care Act of 2006 ("TRRHCA") enacted on December 20, 2006, which is detailed below.

The TRRHCA includes important changes to the Coal Act that impacts all companies required to contribute to the CBF. Effective October 1, 2007, the Social Security Administration ("SSA") revoked all beneficiary assignments made to companies that did not sign a 1988 UMWA contract ("reachback companies") but their premium relief is phased-in. The reachback companies paid their full premium obligation in the current plan year that ended September 30, 2007. However, they will pay only 55% of their plan year 2008 assessed premiums, 40% of their plan year 2009 assessed premiums, and 15% of their plan year 2010 assessed premiums. General United States Treasury money will be transferred to the CBF to make up the difference. After 2010, reachback companies will have no further obligations to the CBF, and transfers from the United States Treasury will cover all of the health care costs for retirees and dependents previously assigned to reachback companies. Some of our subsidiaries are considered reachback companies under the TRRHCA.

11. Workers' Compensation and Black Lung Benefits

Workers' compensation and black lung benefit obligation consisted of the following:

	December 31, 2007	December 31, 2006
	(In Thousands)	
Accrued self-insured black lung obligation	$ 53,412	$ 53,284
Workers' compensation (traumatic injury)	58,788	56,042
Total accrued workers' compensation and black lung	112,200	109,326
Less amount included in Other current liabilities	21,498	20,099
Workers' compensation & black lung in Other noncurrent liabilities	$ 90,702	$ 89,227

The amount of workers' compensation (traumatic liability) related to self-insurance was $56.7 million and $52.3 million at December 31, 2007 and 2006, respectively. Weighted average actuarial assumptions used in the determination of the self-insured portion of workers' compensation (traumatic injury) liability at December 31, 2007 and 2006 included a discount rate of 5.00% and the accumulated black lung obligation included a discount rate of 6.50% and 5.90% at December 31, 2007 and 2006, respectively.

A reconciliation of changes in the self-insured black lung obligation is as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(In Thousands)	
Beginning of year accrued self-insured black lung obligation	$ 53,284	$ 50,779
Service cost	2,495	2,619
Interest cost	3,117	2,861
Actuarial gain	(3,989)	(1,601)
Benefit payments	(1,495)	(1,374)
Accrued self-insured black lung obligation	$ 53,412	$ 53,284

As discussed in Note 1, we adopted SFAS 158 on December 31, 2006. According to the adoption provisions, we recognized the accumulated black lung obligation in the Consolidated Balance Sheet, decreasing the black lung liability by $16.6 million to $53.3 million ($50.3 million in Other noncurrent liabilities at December 31, 2006 and $3.0 million in Other current liabilities). The $16.6 million decrease, net of the deferred tax of $6.5 million, was recorded in Accumulated other comprehensive loss.

The table below details the changes to Accumulated other comprehensive loss related to black lung benefits in accordance with SFAS 158:

	2007	2006
	(In Thousands)	
	Net gain	Net gain
January 1 beginning balance	$ (10,102)	$ -
Changes to Accumulated other comprehensive loss	(485)	(10,102)
December 31 ending balance	(10,587)	(10,102)

We expect to recognize $3.5 million of net actuarial gain in 2008.

Expenses for black lung benefits and workers' compensation related benefits include the following components:

	Year Ended December 31, 2007	December 31, 2006	December 31, 2005
		(In Thousands)	
Self-insured black lung benefits:			
Service cost	$ 2,495	$ 2,619	$ 2,392
Interest cost	3,117	2,861	2,694
Amortization of actuarial gain	(3,194)	(3,759)	(4,691)
	2,418	1,721	395
Other workers' compensation benefits	30,842	36,381	40,609
	$ 33,260	$ 38,102	$ 41,004

Payments for benefits, premiums and other costs related to black lung and workers' compensation liabilities were $29.6 million, $33.2 million and $39.9 million for the years ended December 31, 2007, 2006 and 2005, respectively.

The actuarial assumptions used in the determination of self-insured black lung benefits expense included discount rates of 5.90% for the year ended December 31, 2007 and 5.75% for the years ended December 31, 2006 and 2005, respectively.

Our self-insured black lung obligation is calculated using assumptions regarding future medical cost increases and cost of living increases. Federal black lung benefits are subject to cost of living increases. State benefits increase only until disability, and then remain constant. We assume a 6.50% annual medical cost increase and a 3.0% cost of living increase in determining our black lung obligation and the annual black lung expense. Assumed medical cost and cost of living increases significantly affect the amounts reported for our black lung expense and obligation. A one-percentage point change in each of assumed medical cost and cost of living trend rates would have the following effects:

	1-Percentage Point Increase	1-Percentage Point Decrease
Increase/decrease in medical cost trend rate:		
Effect on total of service and interest costs components	$ 165	$ (133)
Effect on accumulated black lung obligation	$ 1,344	$ (1,101)
Increase/decrease in cost of living trend rate:		
Effect on total service and interest cost components	$ 655	$ (530)
Effect on accumulated black lung obligation	$ 5,526	$ (4,556)

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid related to the self-insured black lung obligation:

	Expected Benefit Payments
	(In Thousands)
2008	$ 3,299
2009	3,442
2010	3,576
2011	3,706
2012	3,836
Years 2013 to 2017	20,871

12. Stock Plans

We have stock incentive plans to encourage employees and nonemployee directors to remain with the Company and to more closely align their interests with those of our shareholders.

Description of Stock Plans

The Massey Energy Company 2006 Stock and Incentive Compensation Plan (the "2006 Plan"), which was approved by our shareholders and became effective on June 28, 2006 replaces the five stock-based compensation plans (the "Prior Plans") we had in place prior to the approval of the 2006 Plan, all of which had been approved by our shareholders. The Prior Plans include the following:

- Massey Energy Company 1996 Executive Stock Plan, as amended and restated effective November 30, 2000 (the"1996 Plan"),
- Massey Energy Company 1997 Stock Appreciation Rights Plan, as amended and restated effective November 30, 2000 (the "SAR Plan"),
- Massey Energy Company 1999 Executive Performance Incentive Plan, as amended and restated effective November 30, 2000 (the "1999 Plan"),
- Massey Energy Company Stock Plan for Non-Employee Directors, as amended and restated effective May 24, 2005 (the "1995 Plan"),
- Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors, as amended and restated effective May 24, 2005 (the "1997 Plan").

Stock-based compensation has been granted under the 2006 Plan and the Prior Plans in the manner described below. Issued and outstanding stock-based compensation has been granted to officers and certain key employees in accordance with the provisions of the 1996 Plan, the SAR Plan, the 1999 Plan, and the 2006 Plan. Issued and outstanding stock-based compensation has been granted to non-employee directors in accordance with the provisions of the 1995 Plan, the 1997 Plan and the 2006 Plan. The Compensation Committee of the Board of Directors administers the 1996 Plan, the 1999 Plan, the SAR Plan and the 2006 Plan. A committee comprised of non-participating board members administers the 1995 Plan and the 1997 Plan.

The 1996 Plan provided for grants of stock options and restricted stock. The 1999 Plan provided for grants of stock options, restricted stock, incentive awards and stock units. The SAR Plan provided for grants of SARs. The 1995 Plan provided for grants of restricted stock and restricted units. The 1997 Plan provided for grants of restricted stock. As of June 28, 2006, grants can no longer be made under the Prior Plans, except for the 1996 Plan, under which grants could no longer be made as of March 2, 2006. All awards previously granted that are outstanding under the Prior Plans will remain effective in accordance with the terms of their grant.

The aggregate number of shares of Common Stock that may be issued for future grant under the 2006 Plan as of December 31, 2007 was 2,400,244 shares, which was computed as the 3,500,000 shares specifically authorized in the 2006 Plan, less grants made in 2006 and 2007, plus the number of shares that (i) were represented by restricted stock or unexercised vested or unvested stock options that previously have been granted and were outstanding under the Prior Plans as of June 28, 2006 and (ii) expire or otherwise lapse, are terminated or forfeited, are settled in cash, or are withheld or delivered to us for tax purposes at any time after June 28, 2006. The 2006 Plan provides for grants of stock options, SARs, restricted stock, restricted units, unrestricted stock and incentive awards.

Although we have not expressed any intent to do so, we have the right to amend, suspend, or terminate the 2006 Plan at any time by action of our board of directors. However, no termination, amendment or modification of the 2006 Plan shall in any manner adversely affect any award theretofore granted under the 2006 Plan, without the written consent of the participant. If a change in control were to occur (as defined in the plan documents), certain options may become immediately vested, but only upon termination of the option holder's service.

Accounting for Stock-Based Compensation

Total compensation expense recognized for stock-based compensation during the year ended December 31, 2007, 2006 and 2005 was $19.2 million, $7.3 million and $23.1 million, respectively. The total income tax benefit recognized in the consolidated statement of income for share based compensation arrangements during the year ended December 31, 2007, 2006 and 2005 was approximately $7.5 million, $2.8 million and $9 million, respectively. We recognize compensation expense on a straight-line basis over the vesting period for the entire award for any awards with graded vesting.

As a result of adopting FAS 123R, we recognized non-cash stock-based compensation expense for stock options of approximately $6.1 million (pre-tax) in Selling, general and administrative expense for the year ended December 31, 2006. The total income tax benefit recognized on this compensation expense was approximately $2.4 million. Income before income taxes, Net income and Earnings per share for the year ended December 31, 2006 were $6.1 million, $3.7 million and $0.05 lower, respectively, than if we had continued to account for share-based compensation under APB No. 25. As of December 31, 2007 and 2006, there was $11.1 million and $15 million, respectively, of total unrecognized compensation cost related to stock options expected to be recognized over a weighted-average period of approximately 1.8 years and 2.4 years, respectively. In the years ended December 31, 2007 and 2006, we also reflected $0.4 million and $1.1 million, respectively, of excess tax benefits as a financing cash flow in the consolidated statement of cash flows resulting from the exercise of stock options.

Prior to the adoption of FAS 123R, we accounted for stock options in accordance with APB No. 25, under which no compensation expense was recorded because the exercise price of stock options equaled the market price of the underlying stock on the date of grant. Had we adopted FAS 123R in prior periods, the impact of that statement would have approximated the impact of FASB Statement No. 123, "Accounting for Stock-based Compensation" (as if the fair-value-based recognition provisions of that statement had been applied) as shown in the following table:

	Year Ended December 31, 2005
	(In Thousands, Except Per Share Amounts)
Net loss, as reported	$ (101,638)
Deduct: Total stock-based employee compensation expense for stock options determined under Black-Scholes option pricing model (net of tax)	(3,959)
Pro forma net loss	$ (105,597)
Loss per share:	
Basic - as reported	$ (1.33)
Basic - pro forma	$ (1.38)
Diluted - as reported	$ (1.33)
Diluted - pro forma	$ (1.38)

Equity instruments

We have granted stock options to employees under the 2006 Plan, the 1999 Plan and the 1996 Plan. These options typically have a requisite service period of three to four years, though there are some awards outstanding with requisite service periods of one year up to four years. Vesting generally occurs ratably over a three or four-year period, though some stock options fully vest upon the earlier to occur of meeting certain performance criteria or four years from the date of grant. The maximum contractual term of stock options granted is 10 years.

We value stock options using the Black-Scholes valuation model, which employs certain key assumptions. We estimate volatility using both historical and market data over the contractual term of the options granted. The dividend yield is calculated on the current annualized dividend payment and the stock price at the date of grant. The expected term is based on historical data and exercise behavior. The risk-free interest rate is based on the zero-coupon Treasury bond rate in effect at the date of grant. The fair value of options granted during the three years ended December 31, 2007. 2006 and 2005 was calculated using the following estimated weighted average assumptions:

	Years Ended December 31,		
Options Granted	2007	2006	2005
Number of shares underlying options	556,979	642,434	842,222
Contractual term in years	10	10	10
Assumptions used to estimate fair value:			
Expected dividend yield	0.6% - 0.7%	0.4% - 0.7%	0.3% - 0.4%
Expected volatility	46% - 50%	46% - 55%	53% - 55%
Risk-free interest rate	3.00% - 4.74%	4.82% - 4.85%	3.82% - 4.41%
Expected term in years	1.2 - 4.25	1.2 - 5	1.3 - 5
Weighted-average fair value estimates at grant date:			
In thousands	$ 5,542	$ 5,192	$ 14,309
Fair value per share	$ 9.95	$ 8.08	$ 16.99

A summary of option activity under the plans for the year ended December 31, 2007 is presented below:

	Number of Options	Weighted average exercise price	Weighted average contractual term (years)	Aggregate Intrinsic Value
	(In Thousands, Except Exercise Price and Contractual Term)			
Outstanding at December 31, 2006	2,795	$ 19.83		
Granted	557	29.46		
Exercised	(300)	13.33		
Forfeited/expired	(378)	34.05		
Outstanding at December 31, 2007	2,674	$ 26.39	7.6	$ 26,656
Exercisable at December 31, 2007	1,217	$ 21.25	6.5	$ 18,350

We received $4.0 million, $2.1 million and $7.2 million in cash proceeds from the exercise of stock options for the years ended December 31, 2007, 2006 and 2005, respectively. The intrinsic value of stock options exercised was $4.5 million, $3.5 million and $12.8 million for the years ended December 31, 2007, 2006 and 2005, respectively.

We have granted restricted stock to our employees under the 2006 Plan and 1999 Plan and to non-employee directors under the 1995 Plan and 1997 Plan. Restricted stock awards are valued on the date of grant based on the closing value of our stock. As of December 31, 2007, there was $10.3 million of unrecognized compensation cost related to restricted stock expected to be recognized over the next four years. With the adoption of FAS 123R, unearned compensation is recorded on a net basis in Additional capital.

A summary of the status of restricted stock at December 31, 2007, and changes for the year then ended is presented below:

(Shares In Thousands)	Shares	Weighted average grant date fair value
Unvested at December 31, 2006	516	$ 27.71
Granted	209	$ 28.48
Vested	(148)	$ 25.60
Forfeited	(62)	$ 27.99
Unvested at December 31, 2007	515	$ 28.64

The fair value of restricted stock vested during the years ended December 31, 2007, 2006 and 2005 was $3.8 million, $3.6 million and $7.6 million, respectively.

Liability instruments

We use the fair value method to recognize compensation cost associated with SARs. At each December 31, 2007, 2006 and 2005, there were 262,500 vested SARs outstanding and exercisable. The weighted average exercise price of these SARs was $29.19 per SAR; the weighted average contractual term was 5.8 years.

We also issue stock incentive units, which are classified as liabilities. They are settled with a cash payment for each unit vested, equal to the fair market value of Common Stock on the vesting date.

	For the years ended December 31, 2007	2006
Awarded	310,900	411,372
Settled	81,461	80,261
Settlement amount (in millions)	$ 2.3	$ 2.1

13. Lease Obligations

We lease two office buildings and certain mining and other equipment under various lease agreements. Certain of these leases provide options for the purchase of the property at the end of the initial lease term, generally at its then fair market value, or to extend the terms at its then fair rental value. Certain of these leases contain financial covenants that may require an accelerated buyout of the lease if the covenants are violated. Rental expense for the years ended December 31, 2007, 2006 and 2005 was $39.7 million, $46.4 million and $42.4 million, respectively.

During 2007, we sold and leased-back certain mining equipment. We received net proceeds of $13.1 million, resulting in net gains of $1.2 million, which we deferred. The gains are being recognized ratably over the term of the leases, which range from 5 to 5.5 years. At lease termination, the leases contain renewal and purchase options at an amount approximating fair value. The leases are being accounted for as operating leases.

During 2006, we sold and leased-back certain mining equipment. We received net proceeds of $21.8 million with no resulting gain or loss on the transaction. At lease termination, the leases contain renewal and purchase options at an amount approximating fair value. The leases are being accounted for as operating leases.

During 2005, we sold and leased-back certain mining and other equipment in several transactions. We received net proceeds of $71.7 million, resulting in net gains of $4.1 million, which were deferred. The gains are being recognized ratably over the term of the leases, which range from 3.5 to 8 years. At lease termination, the leases contain renewal and purchase options at an amount approximating fair value. The leases are being accounted for as operating leases.

The following presents future minimum rental payments, by year, required under leases with initial terms greater than one year, in effect at December 31, 2007:

	Capital Leases	Operating Leases
	(In Thousands)	
2008	$ 2,430	$ 42,669
2009	2,256	39,920
2010	2,395	33,784
2011	2,655	23,020
2012	-	16,060
Beyond 2012	-	5,878
Total minimum lease payments	9,736	$ 161,331
Less imputed interest	913	
Present value of minimum capital lease payments	$ 8,823	

14. Appalachian Synfuel, LLC

Appalachian Synfuel, LLC ("Appalachian Synfuel") was formed in 1997. As a provider of synthetic fuel, Appalachian Synfuel generates tax credits pursuant to Section 45K (formerly Section 29) of the IRC for its owners; however, because of our tax position we are unable to utilize the tax credits generated by Appalachian Synfuel. In order to monetize the value of our investment, we sought to sell an interest in Appalachian Synfuel to an entity that could benefit currently from the tax credits generated. In order to facilitate such a transaction, the synfuel operating agreement was amended to divide the ownership interest in three tranches, Series A, Series B and Series C.

Under the amended Appalachian Synfuel agreement, the Series A owner generally is entitled to the risks and rewards of the first 475,000 tons of production, including the right to the related tax credits. The Series B owner is generally entitled to the risks and rewards of all excess production up to the rated capacity of 1.2 million tons. The Series C owner is responsible for providing recourse working capital loans to Appalachian Synfuel going forward at a specified indexed interest rate. As a result, the Series C owner will fund the daily operations of Appalachian Synfuel. The Series C owner also has the responsibility at the end of the term of the Appalachian Synfuel agreement to wind up the affairs of Appalachian Synfuel, disposing of all assets and settling liabilities.

We sold 99% of the Series A and Series B interest in Appalachian Synfuel in 2001 and 2002 and received cash of $7.2 million, a recourse promissory note for $34.6 million that was paid in quarterly installments of $1.9 million including interest, and a contingent promissory note that was paid on a cents per Section 45 credit dollar earned based on synfuel tonnage shipped. The agreement provides that the payments under the contingent promissory note may be reduced or eliminated if the price of oil remains above a certain threshold price set by the IRS (the "threshold price"). Once the threshold price is reached, the Section 45K credits will be phased out ratably over an approximate $16.00 per barrel range above the threshold price. The threshold price for 2007 is expected to be set by the IRS in April 2008. For fiscal year 2007, the average price of West Texas Intermediate crude oil was approximately $72.19 per barrel. At this price level a portion of the Section 45K credits for 2007 will likely be phased out, which reduced the amount of income we accrued in 2007 from payments to be received under the contingent promissory note. To the extent that the estimated phase-out amount is different than the actual phase-out amount, we will recognize an adjustment in the first quarter of 2008. Our subsidiary, Marfork Coal Company, Inc., managed the facility under an operating agreement, which was terminated as of December 31, 2007.

15. Concentrations of Credit Risk and Major Customers

We are engaged in the production of coal for the utility industry, steel industry and industrial markets. The following chart lists the percentage of each type of Produced coal revenue generated by market:

	For the years ended December 31,		
	2007	2006	2005
Utility coal	60%	62%	60%
Metallurgical coal	30%	28%	29%
Industrial coal	10%	10%	11%

Our mining operations are conducted in southern West Virginia, eastern Kentucky and western Virginia. Our coal is marketed primarily in the United States.

For the years ended December 31, 2007, 2006 and 2005, approximately 11%, 11% and 13%, respectively, of Produced coal revenue was attributable to sales to affiliates of American Electric Power Company, Inc. For the year ended December 31, 2005 approximately 12% of Produced coal revenue was attributable to sales to affiliates of DTE Energy Corporation. At December 31, 2007, approximately 56%, 28% and 16% of Trade receivables represents amounts due from utility customers, metallurgical customers and industrial customers, respectively, compared with 55%, 28% and 17%, respectively, as of December 31, 2006.

Our Trade and other accounts receivable are subject to potential default by customers. In prior years, certain of our customers have filed for bankruptcy resulting in bad debt charges. In an effort to mitigate credit-related risks in all customer classifications, we maintain a credit policy, which requires scheduled reviews of customer creditworthiness and continuous monitoring of customer news events that might have an impact on their financial condition. Negative credit performance or events may trigger the application of tighter terms of sale, requirements for collateral or, ultimately, a suspension of credit privileges. We establish bad debt reserves to specifically consider customers in financial difficulty and other potential receivable losses. In establishing the reserve, we consider the financial condition of individual customers and probability of recovery in the event of default. We charge off uncollectible receivables once legal potential for recovery is exhausted.

16. Fair Value of Financial Instruments

We used the following methods and assumptions to estimate our fair value disclosures for financial statements as of December 31, 2007 and 2006:

Cash and cash equivalents: The carrying value approximates the fair value due to the short maturity of these instruments.

Long-term debt: At December 31, 2007, the combined fair value estimate of our 6.875% Notes, 6.625% Notes, 2.25% Notes and 4.75% Notes outstanding was $1,050.1 million based on available market information. At December 31, 2006, the combined fair value estimate of our 6.875% Notes, 6.625% Notes, 2.25% Notes and 4.75% Notes outstanding was $1,063.8 million based on available market information at that date.

17. Contingencies

Wheeling-Pittsburgh Steel

On April 27, 2005, Wheeling-Pittsburgh Steel Corporation ("WPS") sued our subsidiary Central West Virginia Energy Company ("CWVE") in the Circuit Court of Brooke County, West Virginia, seeking (a) an order requiring CWVE to specifically perform its obligations under a Coal Supply Agreement ("CSA") and (b) compensatory damages due to CWVE's alleged failure to perform under the CSA and for alleged damages to WPS's coke ovens. WPS later amended its complaint to add Mountain State Carbon, LLC ("MSC") as a plaintiff, us as a defendant, and claims for bad faith, misrepresentation and punitive damages. It is CWVE's position that its failure to perform was excused due to the occurrence of events that rendered performance commercially impracticable and/or *force majeure* events as defined by the parties in the CSA, including unforeseen labor shortages, mining and geologic problems at certain of our coal mines, railroad car shortages, transportation problems and other events beyond our control. With respect to the claims based upon alleged bad faith and misrepresentation, and the request for the imposition of punitive damages, it is the position of CWVE and us that no independent tort claim, separate and apart from the breach of contract claims had been alleged against either CWVE or us and, as such, no damages, whether compensatory or punitive, were recoverable. It is also the position of CWVE and us that no acts of bad faith or misrepresentation occurred.

On May 29, 2007, the trial commenced. On July 2, 2007, the jury awarded damages in favor of WPS and MSC in the amount of $219.9 million, comprised of $119.9 million compensatory damages for breach of contract and misrepresentation and $100 million for punitive damages.

On July 30, 2007, a hearing was held by the trial court to review the punitive damages award, and to consider pre-judgment interest and a counterclaim filed by CWVE related to damages for non-payment of the escalated purchase price under the CSA for coal delivered to MSC in November and December 2006. At the hearing, the trial court awarded WPS and MSC pre-judgment interest of approximately $24 million and awarded CWVE approximately $4.5 million (including pre-judgment interest) on the counterclaim. On August 2, 2007, the trial court entered the jury award of compensatory and punitive damages, which, including the above mentioned pre-judgment interest of $24 million, totals approximately $240 million (net of the $4.5 million awarded to CWVE).

On September 26, 2007, the trial court held a hearing on the issue of security for the judgment pending appeal to the West Virginia Supreme Court of Appeals. On September 28, 2007, the trial court ordered that a bond be posted in the amount of $50 million. The $50 million appeal bond was posted with the Court on October 25, 2007, which stays this matter pending disposition of our appeal.

On December 10, 2007, we and CWVE filed separate "Petitions for Appeal" with the West Virginia Supreme Court of Appeals (the "Court") seeking, among other things, review of certain rulings made by the trial court and reversal of the judgments against them. The points raised on appeal included, among other things, (i) the propriety of allowing WPS to proceed with both contract and tort claims where the tort arose out of performance of the contract, (ii) the propriety of the punitive damages award, (iii) whether WPS proved the elements of its misrepresentation and contract claims, and (iv) correctness of certain evidentiary rulings.

We believe, in consultation with legal counsel, that we have strong legal arguments to raise on appeal to the West Virginia Supreme Court of Appeals that create significant uncertainty regarding the ultimate outcome of this matter. Given the size of the punitive damages awarded, West Virginia case precedent, and the significant legal questions the case presents for appeal, we believe it is probable that the West Virginia Supreme Court of Appeals will agree to hear our appeal. Ultimately, we believe it is unlikely any punitive damages will be assessed in this matter. We further believe in consultation with legal counsel that due to matters of law in the conduct of the recently completed trial, there is a strong possibility that the West Virginia Supreme Court of Appeals will remand the compensatory damages claim for retrial or significantly reduce the amount of the compensatory damages awarded by the jury.

We believe the range of possible loss in this matter is from $16 million to $244 million, prior to post-judgment interest or other costs. The minimum loss we expect to incur upon final settlement or adjudication is the amount of excess costs incurred by WPS to acquire coal required but not delivered under the CSA (plus pre-judgment interest) adjusted for performance excused by events of *force majeure*. Amounts in excess of this amount may ultimately be awarded if the West Virginia Supreme Court of Appeals upholds the circuit court's decisions, in whole or in part, or if the West Virginia Supreme Court of Appeals remands the case for retrial and a jury awards the plaintiffs an amount in excess of what we have accrued. We are unable to predict the ultimate outcome of this matter and believe there is no amount in the range that is a better estimate than any other amount given the various possible outcomes on appeal. Included in these reasonably possible outcomes are reversal of the compensatory damage and punitive awards, remand and retrial, or reduction of some or all of the awards. As there is no amount in the range that is a better estimate than any other amount, the minimum amount in the range has been accrued (included in Other current liabilities). It is reasonably possible that our judgments regarding these matters could change in the near term, resulting in the recording of additional material losses that would affect our operating results and financial position.

Our insurance carriers are in the early stages of their investigation and handling of this matter. We believe that we have a valid claim for coverage for at least certain aspects of the underlying litigation. However, we are not able at this time to predict the amount of any insurance recovery. Potential recoveries from our insurance carriers for any losses that may eventually arise from this matter have not been taken into consideration in determining our accrual for this matter.

Harman

In December 1997, A.T. Massey's then subsidiary Wellmore Coal Corporation ("Wellmore") declared force majeure under its coal supply agreement with Harman Mining Corporation ("Harman") and reduced the amount of coal to be purchased from Harman. On October 29, 1998, Harman and its sole shareholder ("Harman plaintiffs") sued A.T. Massey and five of its subsidiaries ("Massey Defendants") in the Circuit Court of Boone County, West Virginia, alleging that the Massey Defendants tortiously interfered with Wellmore's agreement with Harman, causing Harman to go out of business. On August 1, 2002, the jury awarded the plaintiffs $50 million in compensatory and punitive damages. On April 5, 2007, the West Virginia Supreme Court of Appeals accepted the Massey Defendants' Petition for Appeal. Oral arguments were held on October 10, 2007. On November 21, 2007, the Court issued a 3-2 majority opinion reversing the judgment against the Massey Defendants and remanding the case to the Circuit Court of Boone County with directions to enter an order dismissing the case, with prejudice, in its entirety. The Harman plaintiffs filed motions asking the Court to conduct a rehearing in the case. On January 24, 2008, the Court decided to rehear the case, which will be re-argued on March 12, 2008. We do not expect the Court to change its November 21, 2007 ruling, but such a result, while remote, is possible. If the Harman plaintiffs are unsuccessful, as expected the Harman plaintiffs may then petition the United States Supreme Court to review the West Virginia Supreme Court's dismissal of their claims. We believe that the United States Supreme Court will refuse to hear their appeal. The contingent letter of credit of $55 million securing the appeal bond has been cancelled and we reversed the accrual of $22 million previously recorded in Cost of produced coal revenue. We also reversed the $11.6 million accrual for interest in Interest expense.

West Virginia Flooding

Since July 2001, we and nine of our subsidiaries have been sued in 17 consolidated civil actions filed in the Circuit Courts of Boone, Fayette, Kanawha, McDowell, Mercer, Raleigh and Wyoming Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding on or about July 8, 2001. Along with 32 other consolidated cases not involving us or our subsidiaries, these cases cover approximately 4,300 plaintiffs seeking unquantified compensatory and punitive damages from approximately 200 defendants. The West Virginia Supreme Court of Appeals transferred all 49 cases (the "Referred Cases") to the Circuit Court of Raleigh County, West Virginia, to be handled by a mass litigation panel of three judges. The panel judges will hold multiple trials, each relating to all or part of a watershed. On January 18, 2007, a panel judge dismissed all claims asserted by all plaintiffs within the Coal River watershed, which directly involves approximately 400 plaintiffs and we believe impacts another 800 plaintiffs. Plaintiffs filed a petition seeking appeal of this decision with the West Virginia Supreme Court of Appeals, which was heard and granted on October 24, 2007. The appeal will likely be heard and decided in 2008. We believe we have insurance coverage applicable to these matters.

Since August 2004, five of our subsidiaries have been sued in six civil actions filed in the Circuit Courts of Boone, McDowell, Mingo, Raleigh, Summers, and Wyoming Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding on or about May 2, 2002. These complaints cover approximately 355 plaintiffs seeking unquantified compensatory and punitive damages from approximately 35 defendants.

Since May 2006, we and twelve of our subsidiaries have been sued in three civil actions filed in the Circuit Courts of Logan and Mingo Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding between May 30 and June 4, 2004. Four of our subsidiaries have been dismissed from one of the Logan County cases. These complaints cover approximately 425 plaintiffs seeking unquantified compensatory and punitive damages from approximately 52 defendants. Two of these cases (both in Logan County) have been stayed pending appeal of the Coal River watershed decision noted above. In the Mingo County case, a motion to stay pending appeal of the Coal River watershed decision has been made.

On April 10, 2007, two of our subsidiaries were sued in a civil action filed in the Circuit Court of Boone County, West Virginia, for alleged property damages and personal injuries arising out of flooding on or about July 29, 2001. This complaint covers 17 plaintiffs seeking unquantified compensatory and punitive damages from five defendants. On November 6, 2007, we filed a motion to dismiss, or in the alternative, to certify questions to the West Virginia Supreme Court of Appeals in response to the Complaint. Subsequently, we settled with 16 of 17 of the Plaintiffs. With respect to the remaining Plaintiff, the Court granted a motion to withdraw filed by her counsel and she has yet to notify the Court as to whether she intends to prosecute her claims. We are pursuing dismissal on the grounds initially asserted in the pending motion to dismiss.

We believe these matters will be resolved without a material impact on our cash flows, results of operations or financial condition.

West Virginia Trucking

Since January 2003, an advocacy group and residents in Boone, Kanawha, Mingo and Raleigh Counties, West Virginia, filed 17 suits in the Circuit Courts of Kanawha and Mingo Counties, West Virginia, against us and 15 of our subsidiaries. The claims against us and three of our subsidiaries were dismissed. Plaintiffs alleged that we and our subsidiaries named in the suit illegally transported coal in overloaded trucks, causing damage to state roads, thereby interfering with plaintiffs' use and enjoyment of their properties and their right to use the public roads. Plaintiffs seek injunctive relief and unquantified compensatory and punitive damages. The West Virginia Supreme Court of Appeals referred the consolidated lawsuits, and three similar lawsuits against other coal and transportation companies not involving us or our subsidiaries, to the Circuit Court of Lincoln County, West Virginia, to be handled by a mass litigation panel of one judge. Plaintiffs filed motions requesting class certification. On June 7, 2007, plaintiffs voluntarily dismissed their public nuisance claims seeking monetary damages for road and bridge repairs. Defendants filed a motion requesting that the mass litigation panel judge recommend to the West Virginia Supreme Court of Appeals that the cases be sent back to the circuit courts of origin for resolution. The Court has not ruled on that motion. Defendants have moved to dismiss any remaining public nuisance claims and to limit any damages for nuisance to two years prior to the filing of any suit. Prior to the hearing on those motions, plaintiffs agreed to an order limiting any damages for nuisance to two years prior to the filing of any suit. The motion to dismiss any remaining public nuisance claims was resisted by plaintiffs and argued at a hearing on December 14, 2007. The Court has set a hearing on plaintiffs' motion for class certification for March 21, 2008. No date has been set for a trial. We believe we have insurance coverage applicable to these matters and that they will be resolved without a material impact on our cash flows, results of operations or financial condition.

Well Water Contamination

Since September 2004, approximately 710 plaintiffs filed approximately 400 suits against us and our subsidiary Rawl Sales & Processing Co. in the Circuit Court of Mingo County, West Virginia, for alleged property damage and personal injuries arising out of slurry injection and impoundment practices allegedly contaminating plaintiffs' water wells. Subsequent to such filings, approximately 55 suits have either been voluntarily dismissed by the plaintiffs or dismissed by the Court. Plaintiffs seek injunctive relief and unquantified compensatory and punitive damages. Specifically, plaintiffs are claiming that defendants' activities during the period of 1978 through 1987 rendered their property valueless and request monetary damages to pay, *inter alia*, the value of their property and future water bills. In addition, many plaintiffs are also claiming that their exposure to the contaminated well water caused neurological injury or physical injury, including cancers, kidney problems, and gall stones. Finally, all plaintiffs are claiming entitlement to medical monitoring for the next thirty (30) years. While we have not received damage amounts for all plaintiffs at this time, we estimate that plaintiffs will claim in excess of $50 million in special damages. Plaintiffs also request unliquidated compensatory damages for pain and suffering, annoyance and inconvenience. Trial is scheduled to commence on May 27, 2008. We believe we have strong defenses to these claims. While we have disputes with some of our insurers, we believe we have insurance coverage applicable to these matters and that they will be resolved without a material impact on our cash flows, results of operations or financial condition.

Surface Mining Fills

Since September 2005, three environmental groups sued the United States Army Corps of Engineers ("Corps") in the United States District Court for the Southern District of West Virginia (the "trial Court"), asserting the Corps unlawfully issued permits to four of our surface mines to construct mining fills. The suit alleges the Corps failed to comply with the requirements of both Section 404 of the Clean Water Act and the National Environmental Policy Act, including preparing environmental impact statements for individual permits. We intervened in the suit to protect our interests. On March 23, 2007, the trial Court rescinded four of our permits, resulting in the temporary suspension of mining at these surface mines. We appealed that ruling to the United States Court of Appeals for the Fourth Circuit. On April 17, 2007, the trial Court partially stayed its ruling, permitting mining to resume in certain fills that were already under construction. On June 14, 2007, the trial Court issued an additional ruling, finding the Corps improperly approved placement of sediment ponds in streams below fills on the four permits in question. The trial Court subsequently modified its ruling to allow these ponds to remain in place, as the ponds and fills have already been constructed. The trial Court's ruling could impact the issuance of permits for the placement of sediment ponds for future operations. If the permits for the fills or sediment ponds are ultimately held to be unlawfully issued, production could be affected at these surface mines, and the process of obtaining new Corps permits for all surface mines could become more difficult. We do not expect any material impact to our financial statements through 2008 and will continue to monitor developments in the matter.

Virginia Electric and Power Company

On December 30, 2005, Virginia Electric and Power Company ("VEPCO") filed suit in the Circuit Court of the City of Richmond, Virginia against A.T. Massey and Massey Coal Sales Company, Inc. ("MCS"). On April 11, 2007, A.T. Massey and MCS filed their Answer, Affirmative Defenses and Counterclaim. On October 8, 2007, the parties entered into a confidential settlement agreement to settle the lawsuit and counterclaim for complete releases and a dismissal with prejudice. The dismissal order was entered by the Richmond circuit court on October 10, 2007. The financial impact of the settlement was included in the third quarter in Cost of produced coal revenue. This matter was resolved without a material impact on our cash flows, results of operations or financial condition.

Clean Water Act

On May 10, 2007, the United States, on behalf of the Administrator of the United States Environmental Protection Agency ("EPA"), filed suit against us and twenty-seven of our subsidiaries in the United States District Court for the Southern District of West Virginia ("District Court"). The suit alleged that a number of our subsidiaries violated the Federal Clean Water Act on thousands of occasions by discharging pollutants in excess of monthly and daily permit limits from 2000 to 2006. On January 17, 2008, a proposed settlement reached with the EPA was filed with the District Court. The settlement, which requires District Court approval, requires us to pay $20 million in penalties and make improvements in our environmental processes. We expect the settlement to be approved by the District Court in the first or second quarter of 2008. We recorded the $20 million in Cost of produced coal revenue in 2007.

Aracoma Mine Fire

In January 2006, one of our subsidiaries, Aracoma Coal Company, experienced a mine fire that resulted in the deaths of two miners. The estates of the two miners have filed a lawsuit in the Circuit Court of Logan County against us and two of our subsidiaries with respect to the incident. A trial in that suit is scheduled for October 2008. We believe we have insurance coverage applicable to this matter.

The federal Mine Safety and Health Administration conducted an investigation into the causes of the fatalities and subsequently issued citations seeking $1.5 million in fines relating to the fatalities. Aracoma Coal Company has appealed those citations.

Additionally, the United States Attorney's Office in the Southern District of West Virginia is conducting a federal grand jury investigation of the incident. Such an investigation could result in criminal fines for Aracoma or other subsidiaries of ours.

While we believe we have sufficient legal reserves for these matters, it is possible that the actual outcome of the matters could vary significantly from those amounts. We will continue to review the amount of our accrual and any adjustment required to increase or decrease the accrual based on development of the matters will be made in the period determined. We believe these matters will be resolved without a material impact on our cash flows, results of operations or financial condition.

Other Legal Proceedings

We are parties to a number of other legal proceedings, incident to our normal business activities. These include contract dispute, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates we do not believe that any liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition. It is reasonably possible, however, that the ultimate liabilities in the future with respect to these lawsuits and claims, in the aggregate, may be material to our cash flows, results of operations or financial condition.

18. Quarterly Information (Unaudited)

The table below details our quarterly financial information for the previous two fiscal years.

	Three Months Ended			
	March 31, 2007	June 30, 2007 (1)	September 30, 2007	December 31, 2007 (2)
	(In Thousands, Except Per Share Amounts)			
Total revenue	$ 607,320	$ 617,802	$ 603,441	$ 584,960
Income before interest and taxes	55.557	60,127	35,343	28,652
Income before taxes	39,531	45,316	20,478	24,178
Net income	32,607	34,938	21,408	5,145
Income per share (basic and diluted):				
Net income	$ 0.40	$ 0.43	$ 0.27	$ 0.06

	Three Months Ended			
	March 31, 2006 (3)	June 30, 2006 (3)	September 30, 2006 (4)	December 31, 2006
	(In Thousands, Except Per Share Amounts)			
Total revenue	$ 559,469	$ 556,116	$ 555,897	$ 548,372
Income before interest and taxes	24,290	20,337	46,614	19,765
Income before taxes	7,617	3,882	30,197	3,328
Income before cumulative effect of accounting change	6,250	3,225	24,156	7,985
Net income	5,611	3,225	24,156	7,985
Income per share (basic and diluted):				
Income before cumulative effect of accounting change	$ 0.08	$ 0.04	$ 0.30	$ 0.10
Net income	$ 0.07	$ 0.04	$ 0.30	$ 0.10

(1) Income for the second quarter of 2007 includes a $5 million non-tax deductible expense related to the EPA lawsuit (see Note 17 for further information) and $10.3 million on the exchange of coal reserves.

(2) Income for the fourth quarter of 2007 includes a $22 million reversal of the accrual and $11.6 million reversal of accrued interest for the Harman lawsuit (see Note 17 for further information), $15 million non-tax deductible expense related to the settlement of an EPA lawsuit (see Note 17 for further information) and $6.7 million pre-tax gain on the sale of a mineral rights override .

(3) During January 2006, our Logan County resource group's Aracoma longwall mine experienced a fire. The mine returned to operational status in July 2006. Costs related to the fire were approximately $5.3 million in the first quarter and $6.4 million in the second quarter.

(4) Income for the third quarter of 2006 includes a $30 million pre-tax gain for the sale of our Falcon reserves (see Note 4 for further information).

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

There have been no changes in, or disagreements with, accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures and Changes in Internal Control Over Financial Reporting

We have established disclosure controls and procedures to ensure that information relating to us, including our consolidated subsidiaries, required to be disclosed in the reports that we file or submit under the Exchange Act, is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act), as of the end of the period covered by this report.

Based on our evaluation as of December 31, 2007, the principal executive officer and principal financial officer have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that the information required to be disclosed in reports that we file or furnish under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2007, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management is required to include in this Form 10-K an internal control over financial reporting report wherein management states its responsibility for establishing and maintaining adequate internal control structure and procedures for financial reporting and assesses the effectiveness of such structure and procedures. This management report follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Massey Energy Company ("Massey") is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Massey's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

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

Massey's management assessed the effectiveness of Massey's internal control over financial reporting as of December 31, 2007. In making this assessment, Massey used the criteria in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment based on those criteria, Massey's management has concluded that, as of December 31, 2007, internal control over financial reporting is effective.

The effectiveness of our internal control over financial reporting as of December 31, 2007, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which follows immediately hereafter.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Massey Energy Company

We have audited Massey Energy Company's internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Massey Energy Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2007 consolidated financial statements of Massey Energy Company and our report dated February 28, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Richmond, Virginia
February 28, 2008

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant

Don L. Blankenship, Age 57

Mr. Blankenship has been a director since 1996. He has been Chairman, Chief Executive Officer and President since November 30, 2000. He has been Chairman, Chief Executive Officer and President of A.T. Massey Coal Company, Inc., our wholly owned and sole, direct operating subsidiary, since 1992. Mr. Blankenship was formerly President and Chief Operating Officer from 1990 to 1991 and President of our subsidiary, Massey Coal Services, Inc., from 1989 to 1991. He joined our subsidiary, Rawl Sales & Processing Co., in 1982. He is a director of the Center for Energy and Economic Development, the National Mining Association and the United States Chamber of Commerce.

Baxter F. Phillips, Jr., Age 61

Mr. Phillips has been Executive Vice President and Chief Administrative Officer since November 2004. Mr. Phillips previously served as Senior Vice President and Chief Financial Officer from September 2003 to November 2004 and as Vice President and Treasurer from 2000 to August 2003. Mr. Phillips joined us in 1981 and has also served in the roles of Corporate Treasurer, Manager of Export Sales and Corporate Human Resources Manager, among others.

J. Christopher Adkins, Age 44

Mr. Adkins has been Senior Vice President and Chief Operating Officer since July 2003. Mr. Adkins joined our subsidiary, Rawl Sales & Processing Co., in 1985 to work in underground mining. Since that time, he has served as section foreman, plant supervisor, President and Vice President of several subsidiaries, President of our Eagle Energy subsidiary, Director of Production of Massey Coal Services, Inc. and Vice President of Underground Production.

Mark A. Clemens, Age 41

Mr. Clemens has been Senior Vice President, Group Operations since July 2007. From January 2003 to July 2007, Mr. Clemens was President of Massey Coal Services, Inc. Mr. Clemens was formerly President of Independence Coal Company, Inc., one of our operating subsidiaries, from 2000 through December 2002 and our Corporate Controller from 1997 to 1999. Mr. Clemens has held a number of other accounting positions and has been with us since 1989.

Michael K. Snelling, Age 51

Mr. Snelling has been Vice President, Surface Operations of our subsidiary, Massey Coal Services, Inc. since June 2005. Mr. Snelling was formerly Director of Surface Mining of Massey Coal Services, Inc. from July 2003 until May 2005. Mr. Snelling joined us in 2000 and has served us in a variety of capacities, including President of our subsidiary, Nicholas Energy Co. Prior to joining us, Mr. Snelling held various positions in the coal industry including engineer, production supervisor, plant supervisor, general foreman, manager of contract mining, superintendent, mine manager and vice president of operations.

Michael D. Bauersachs, Age 43

Mr. Bauersachs has been Vice President, Planning since May 2005. Mr. Bauersachs joined us in 1998, and served as Director of Acquisitions from 1998 until 2005. Prior to joining us, Mr. Bauersachs held various positions with Zeigler Coal Holding Company and Arch Mineral Corporation.

Richard R. Grinnan, Age 39

Mr. Grinnan has been Vice President and Corporate Secretary since May 2006. He served as Senior Corporate Counsel from July 2004 until May 2006. Prior to joining us, Mr. Grinnan was a corporate and securities attorney at the law firm of McGuireWoods LLP in Richmond, Virginia from August 2000 until July 2004.

M. Shane Harvey, Age 38

Mr. Harvey has been Vice President and General Counsel since January 2008. He served as Vice President and Assistant General Counsel from November 2006 until January 2008 and as Corporate Counsel and Senior Corporate Counsel from April 2000 until November 2006. Prior to joining us, Mr. Harvey was an attorney at the law firm of Jackson Kelly PLLC in Charleston, West Virginia from May 1994 until April 2000.

Jeffrey M. Jarosinski, Age 48

Mr. Jarosinski has been Vice President, Finance since 1998 and Chief Compliance Officer since December 2002. From 1998 through December 2002, Mr. Jarosinski was Chief Financial Officer. Mr. Jarosinski was formerly Vice President, Taxation from 1997 to 1998 and Assistant Vice President, Taxation from 1993 to 1997. Mr. Jarosinski joined us in 1988.

John M. Poma, Age 43

Mr. Poma has been Vice President, Human Resources since April 2003. Mr. Poma served as Corporate Counsel from 1996 until 2000 and as Senior Corporate Counsel from 2000 through March 2003. Prior to joining us in 1996, Mr. Poma was an employment attorney with the law firms of Midkiff & Hiner in Richmond, Virginia and Jenkins, Fenstermaker, Krieger, Kayes & Farrell in Huntington, West Virginia.

Eric B. Tolbert, Age 40

Mr. Tolbert has been Vice President and Chief Financial Officer since November 2004. Mr. Tolbert served as Corporate Controller from 1999 to 2004. He joined us in 1992 as a financial analyst and subsequently served as Director of Financial Reporting. Prior to joining us, Mr. Tolbert worked for the public accounting firm Arthur Andersen from 1990 to 1992.

Roger T. Williams, Age 35

Mr. Williams has been Vice President, Sales since November 2006. Mr. Williams previously served as Assistant to the Office of the Chairman since July 2005. Prior to joining us, Mr. Williams worked for Deutsche Bank Group as an investment banker in the energy sector from July 2002 to March 2005, after attending Columbia Business School from January 2001 to June 2002.

David W. Owings, Age 34

Mr. Owings has been Corporate Controller and principal accounting officer since November 2004. Mr. Owings previously served as Manager of Financial Reporting since joining us in 2001. Prior to joining us, Mr. Owings worked at Ernst & Young LLP, the Company's independent registered public accounting firm, serving as a manager from January 2001 through September 2001 and as a senior auditor from October 1998 through January 2001 in the Assurance and Advisory Business Services group.

The following information is incorporated by reference from our definitive proxy statement pursuant to Regulation 14A, which will be filed not later than 120 days after the close of Massey's fiscal year ended December 31, 2007:

- Information regarding the directors required by this item is found under the heading *Election of Directors.*
- Information regarding Massey's Audit Committee required by this item is found under the heading *Committees of the Board.*
- Information regarding Section 16(a) Beneficial Ownership Reporting Compliance required by this item is found under the heading *Section 16(a) Beneficial Ownership Reporting Compliance.*
- Information regarding Massey's Code of Ethics required by this item is found under the heading *Code of Ethics.*

Because Common Stock is listed on the NYSE, our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of May 29, 2007. In addition, we have filed, as exhibits to this annual report on Form 10-K, the certifications of our principal executive officer and principal financial officer required under Section 302 of the Sarbanes Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

Item 11. Executive Compensation

Information required by this item is included in the *Compensation Discussion and Analysis, Compensation of Named Executive Officers, Compensation Committee Interlocks and Insider Participation, and Compensation Committee Report on Executive Compensation* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2007.

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

Information required by this item is included in the *Stock Ownership of Directors and Executive Officers* and *Stock Ownership of Certain Beneficial Owners* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2007.

The following table sets forth as of December 31, 2007, the number of shares of Common Stock authorized for issuance under our equity compensation plan.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights [1]	(b) Weighted-average per share exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders	2,673,857	$26.39	2,400,244
Equity compensation plans not approved by shareholders [2]	-	-	-
Total	2,673,857	$26.39	2,400,244

(1) There are no outstanding warrants or rights.
(2) We do not have any equity compensation plans that have not been approved by our shareholders.

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

Information required by this item is included in the *Certain Relationships and Related Transactions* and *Director Independence* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2007.

Item 14. Principal Accountant Fees and Services

Information concerning principal accountant fees and services contained under the heading *The Audit Committee Report* in the definitive proxy statement pursuant to Regulation 14A, which is incorporated by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2007.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report:

1. Financial Reports:

   Consolidated Statements of Income for the Fiscal Years Ended December 31, 2007, 2006, and 2005

   Consolidated Balance Sheets at December 31, 2007 and 2006

   Consolidated Statements of Cash Flows for the Fiscal Years Ended December 31, 2007, 2006, and 2005

   Consolidated Statements of Shareholders' Equity for the Fiscal Years Ended December 31, 2007, 2006, and 2005

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules: Except as set forth below, all schedules have been omitted since the required information is not present or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the Consolidated Financial Statements and Notes thereto.

   Schedule II—Valuation and Qualifying Accounts

3. Exhibits:

Exhibit No.	Description
3.1	Certificate of Ownership and Merger merging Massey Energy Company with and into Fluor Corporation accompanied by Restated Certificate of Incorporation of Massey Energy Company, as amended [filed as Exhibit 3.1 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
3.2	Restated Bylaws (as amended as of February 19, 2008) of Massey Energy Company [filed as Exhibit 3.1 to Massey's current report on Form 8-K filed February 21, 2008 and incorporated by reference]
4.1	Senior Indenture, dated May 29, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors and Wilmington Trust Company, as Trustee, in connection with the Company's 4.75% Convertible Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed May 30, 2003 and incorporated by reference]
4.2	First Supplemental Indenture, dated May 29, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, supplementing that certain Senior Indenture dated May 29, 2003, in connection with the Company's 4.75% Convertible Senior Notes [filed as Exhibit 4.2 to Massey's current report on Form 8-K filed May 30, 2003 and incorporated by reference]
4.3	Indenture, dated November 10, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.625% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed November 12, 2003 and incorporated by reference]
4.4	Second Supplemental Indenture, dated April 7, 2004, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, supplementing that certain Senior Indenture dated May 29, 2003, in connection with the Company's 2.25% Convertible Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed April 4, 2004 and incorporated by reference]
4.5	Indenture, dated as of December 21, 2005, Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.875% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed December 21, 2005, and incorporated by reference]
10.1	Amended and Restated Credit Agreement dated as of August 15, 2006, among A. T. Massey Coal Company, Inc. and certain of its subsidiaries, as Borrowers, Massey Energy Company and certain of its subsidiaries, as Guarantors, Bank of America, N. A., as Syndication Agent, General Electric Capital Corporation, as Documentation Agent, The CIT Group/Business Credit, Inc., as Collateral Agent, UBS Securities LLC, as Arranger, UBS AG, Stamford Branch, as Administrative Agent, and UBS Loan Finance LLC, as Swingline Lender, and the lenders party thereto [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.2	First Amendment to Amended and Restated Credit Agreement dated March 12, 2007 [filed as Exhibit 10.1 to Massey's quarterly report on Form 10-Q filed May 10, 2007 and incorporated by reference]
10.3	Limited Consent and Second Amendment to Amended and Restated Credit Agreement dated July 19, 2007 [filed as Exhibit 10.1 to Massey's quarterly report on Form 10-Q filed August 9, 2007 and incorporated by reference]
10.4	Massey Energy Company 1982 Shadow Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.8 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.5	Massey Energy Company 1988 Executive Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.6 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.6	Massey Energy Company 1996 Executive Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.13 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.7	Amendment to Massey Energy 1996 Executive Stock Plan [filed as Exhibit 10.4 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.8	Massey Energy Company 1997 Stock Appreciation Rights Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.9 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.9	Massey Energy Company 1999 Executive Performance Incentive Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.1 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.10	Amendment to Massey Energy Company 1999 Executive Performance Incentive Plan [contained in Item 1.01 to Massey's current report on Form 8-K filed February 24, 2006 and incorporated by reference]

Exhibit No.	Description
10.11	Second Amendment to Massey Energy Company 1999 Executive Performance Incentive Plan [filed as Exhibit 10.5 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.12	Massey Energy Company 2006 Stock and Incentive Compensation Plan (as amended and restated effective August 15, 2006) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.13	Amendment to Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.14	Form of Non-Employee Director Initial Restricted Stock Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed February 21, 2008 and incorporated by reference]
10.15	Form of Non-Employee Director Initial Restricted Unit Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed February 21, 2008 and incorporated by reference]
10.16	Form of Non-Employee Director Annual Restricted Stock Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed February 21, 2008 and incorporated by reference]
10.17	Form of stock option agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed November 16, 2007 and incorporated by reference]
10.18	Form of restricted stock agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed November 16, 2007 and incorporated by reference]
10.19	Form of restricted unit agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.4 to Massey's current report on Form 8-K filed November 16, 2007 and incorporated by reference]
10.20	Form of cash incentive award agreement based on earnings before taxes under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.5 to Massey's current report on Form 8-K filed November 16, 2007 and incorporated by reference]
10.21	Form of cash incentive award agreement based on earnings before interest, taxes, deprecation and amortization under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed November 16, 2007 and incorporated by reference]
10.22	Massey Executive Deferred Compensation Program (as amended and restated as of January 1, 2005) [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed February 25, 2005 and incorporated by reference]
10.23	First Amendment to the Massey Executive Deferred Compensation Program [filed as Exhibit 10.10 to Massey's current report on Form 8-K filed November 17, 2005 and incorporated by reference]
10.24	A.T. Massey Coal Company, Inc. Executive Deferred Compensation Plan (as amended and restated as of January 1, 2005) [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed February 25, 2005 and incorporated by reference]
10.25	First Amendment to the A.T. Massey Coal Company, Inc. Executive Deferred Compensation Plan [filed as Exhibit 10.11 to Massey's current report on Form 8-K filed November 17, 2005 and incorporated by reference]
10.26	Second Amendment to the A.T. Massey Coal Company, Inc. Executive Deferred Compensation Plan [filed as Exhibit 10.2 to Massey's quarterly report on Form 10-Q filed August 9, 2006 and incorporated by reference]
10.27	Massey Energy Company Executive Physical Program [filed as Exhibit 10.3 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.28	Massey Executives' Supplemental Benefit Plan (as amended and restated as of January 1, 2005) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed January 5, 2006 and incorporated by reference]
10.29	Massey Executives' Supplemental Benefit Plan Agreement (effective as of January 1, 2005) between Massey and Don L. Blankenship [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed January 5, 2006 and incorporated by reference]
10.30	Letter Agreement dated December 20, 2005 between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.31	Letter Agreement dated December 27, 2006, between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed January 3, 2007 and incorporated by reference]

Exhibit No.	Description
10.32	Letter Agreement dated November 13, 2007, between Massey Energy Company and Don L. Blankenship [filed herewith]
10.33	Retention and Employment Agreement dated November 13, 2007 between Massey Energy Company and John Christopher Adkins [filed herewith]
10.34	Employment Agreement dated May 25, 2006 between Massey Energy Company and Michael K. Snelling [filed herewith]
10.35	Special Successor and Development Retention Program between Fluor Corporation and Don L. Blankenship dated as of September 1998 [filed as Exhibit 10.21 to Fluor's annual report on Form 10-K for the fiscal year ended October 31, 1998 and incorporated by reference]
10.36	Retention and Change in Control Agreement dated November 1, 2005 between Massey Energy Company and Baxter F. Phillips, Jr. [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed November 17, 2005 and incorporated by reference]
10.37	Form of Change in Control Severance Agreement for Tier 1 Participants [filed as Exhibit 10.7 to Massey's current report on Form 8-K filed November 16, 2007 and incorporated by reference]
10.38	Form of Change in Control Severance Agreement for Tier 2 Participants [filed as Exhibit 10.8 to Massey's current report on Form 8-K filed November 16, 2007 and incorporated by reference]
10.39	Form of Change in Control Severance Agreement for Tier 3 Participants [filed as Exhibit 10.9 to Massey's current report on Form 8-K filed November 16, 2007 and incorporated by reference]
10.40	Change in Control Severance Agreement dated as of December 21, 2005 between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.5 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.41	Change in Control Severance Agreement dated as of December 21, 2005 between Massey Energy Company and J. Christopher Adkins [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.42	Change in Control Severance Agreement dated as of December 21, 2005 between Massey Energy Company and Eric B. Tolbert [filed as Exhibit 10.39 to Massey's annual report on Form 10-K filed March 1, 2007 and incorporated by reference]
10.43	Change in Control Severance Agreement dated as of May 25, 2006 between Massey Energy Company and Michael K. Snelling [filed herewith]
10.44	Massey Energy Company 2008 Long Term Incentive Award Program as reported on Massey's current report on Form 8-K [filed November 16, 2007 and incorporated by reference]
10.45	Massey Energy Company 2008 Bonus Program as reported on Massey's current report on Form 8-K [filed November 16, 2007 and incorporated by reference]
10.46	Base salary amounts set for Massey's named executive officers as reported on Massey's current report on Form 8-K [filed November 16, 2007 and incorporated by reference]
10.47	Massey Energy Company Non-Employee Director Compensation Summary (as amended and restated effective November 12, 2007) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed November 16, 2007 and incorporated by reference]
10.48	Massey Energy Company Stock Plan for Non-Employee Directors (as amended and restated effective May 24, 2005) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed May 26, 2005 and incorporated by reference]
10.49	First Amendment to Massey Energy Company Stock Plan for Non-Employee Directors [filed as Exhibit 10.3 to Massey's quarterly report on Form 10-Q filed August 9, 2006 and incorporated by reference]
10.50	Second Amendment to Massey Energy Company Stock Plan for Non-Employee Directors [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.51	Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors (as amended and restated effective May 24, 2005) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed May 31, 2005 and incorporated by reference]
10.52	First Amendment to Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors [filed as Exhibit 10.4 to Massey's quarterly report on Form 10-Q filed August 9, 2006 and incorporated by reference]
10.53	Second Amendment to Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.54	Third Amendment to Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed May 24, 2007 and incorporated by reference]
10.55	Massey Energy Company Deferred Directors' Fees Program (amended and restated effective February 23, 2001) [filed as Exhibit 10.15 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]

Exhibit No.	Description
10.56	Distribution Agreement between Fluor Corporation and Massey Energy Company dated as of November 30, 2000 [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed December 15, 2000 and incorporated by this reference]
10.57	Tax Sharing Agreement between Fluor Corporation, Massey Energy Company and A.T. Massey Coal Company, Inc. dated as of November 30, 2000 [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed December 15, 2000 and incorporated by this reference]
16.1	Letter from Arnett and Foster to the Securities and Exchange Commission, dated November 16, 2007 [filed as Exhibit 16.1 to Massey's current report on Form 8-K filed November 17, 2007 and incorporated by reference]
21	Massey Energy Company Subsidiaries [filed herewith]
23.1	Consent of Independent Registered Public Accounting Firm [filed herewith]
23.2	Consent of Robert H. Furman, recognized Clean Water Act penalty violation expert dated August 9, 2007 [filed as Exhibit 23.1 to Massey's quarterly report on Form 10-Q filed August 9, 2007 and incorporated by reference]
24	Manually signed Powers of Attorney executed by Massey directors [filed herewith]
31.1	Certification of Chief Executive Officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 [filed herewith]
31.2	Certification of Chief Financial Officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 [filed herewith]
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 [furnished herewith]
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 [furnished herewith]

SIGNATURES

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

MASSEY ENERGY COMPANY

February 29, 2008

By: /s/ ERIC B. TOLBERT
Eric B. Tolbert,
Vice President and Chief Financial Officer

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

Signature	Title	Date
Principal Executive Officer and Director:		
/s/ DON L. BLANKENSHIP **Don L. Blankenship**	Chairman, Chief Executive Officer and President	February 29, 2008
Principal Financial Officer:		
/s/ ERIC B. TOLBERT **Eric B. Tolbert**	Vice President and Chief Financial Officer	February 29, 2008
Principal Accounting Officer:		
/s/ DAVID W. OWINGS **David W. Owings**	Controller	February 29, 2008
Other Directors:		
* **James B. Crawford**	Director	February 29, 2008
* **Robert H. Foglesong**	Director	February 29, 2008
* **Richard M. Gabrys**	Director	February 29, 2008
* **E. Gordon Gee**	Director	February 29, 2008
* **Bobby R. Inman**	Director	February 29, 2008
* **Lady Judge**	Director	February 29, 2008
* **Dan R. Moore**	Director	February 29, 2008
* **Baxter F. Phillips, Jr.**	Director, Executive Vice President and Chief Administrative Officer	February 29, 2008

By: /s/ RICHARD R. GRINNAN February 29, 2008
Richard R. Grinnan
Attorney-in-fact

* Manually signed Powers of Attorney authorizing Eric B. Tolbert., Richard R. Grinnan and Jeffrey M. Jarosinski, and each of them, to sign the annual report on Form 10-K for the fiscal year ended December 31, 2007 and any amendments thereto as attorneys-in-fact for certain directors and officers of the registrant are included herein as Exhibits 24.

MASSEY ENERGY COMPANY

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS
(In Thousands)

Description	Balance at Beginning of Period	Amounts Charged to Costs and Expenses	Deductions [1]	Other [2]	Balance at End of Period
YEAR ENDED DECEMBER 31, 2007					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 576	$ (132)	$ -	$ -	$ 444
YEAR ENDED DECEMBER 31, 2006					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 2,063	$ 12	$ (1,499)	$ -	$ 576
YEAR ENDED DECEMBER 31, 2005					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 4,240	$ (1,780)	$ (397)	$ - [3]	$ 2,063

(1) Reserves utilized, unless otherwise indicated.

(2) Reclassifications, unless otherwise indicated.

(3) In 2005, as part of the consideration for the sale of our ownership interest in Big Elk Mining Company, we received a $30 million non-interest bearing note and established an allowance of $11.5 million due to collectibility concerns. This reserve was reversed in the fourth quarter of 2005 as a result of the early repayment of the note.

EXHIBIT 31.1

Section 302 Certification

I, Don L. Blankenship, certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2007 of Massey Energy Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2008

/s/ Don L. Blankenship
Don L. Blankenship
Chairman, Chief Executive Officer and President

EXHIBIT 31.2

Section 302 Certification

I, Eric B. Tolbert, certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2007 of Massey Energy Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2008

/s/ Eric B. Tolbert
Eric B. Tolbert
Vice President and Chief Financial Officer

SHAREHOLDER INFORMATION

Common Stock Information

At February 15, 2008, there were 80,491,644 shares outstanding and approximately 6,800 shareholders of record of Massey Energy's common stock.

Registrar and Transfer Agent

Wells Fargo Shareowner Services℠
Shareowner Relations Department
P.O. Box 64854
St. Paul, MN 55164-0854

For change of address, lost dividends or lost stock certificates, write or telephone:

Wells Fargo Bank, N.A.
P.O. Box 64874
St. Paul, MN 55174-0874
(800) 813-2847

Independent Auditors

Ernst & Young LLP
901 E. Cary Street
Suite 1000
Richmond, VA 23219

Annual Shareholders' Meeting

Massey Energy's annual meeting of shareholders will be held at 9:00 a.m. EDT on May 13, 2008 at:

Jefferson Hotel
101 West Franklin Street
Richmond, VA 23220

Stock Trading

Massey Energy's stock is traded on the New York Stock Exchange. Common stock domestic trading symbol: MEE

Duplicate Mailings

Shares owned by one person but held in different forms of the same name result in duplicate mailings of shareholder information at added expense to the Company. Such duplication can be eliminated only at the direction of the shareholder. Please notify Wells Fargo Shareowner Services℠ in order to eliminate duplication.

Financial Information

Inquiries from shareholders and security analysts should be directed to:

Investor Relations
Massey Energy Company
P.O. Box 26765
Richmond, VA 23261
(866) 814-6512

Website Address

www.masseyenergyco.com

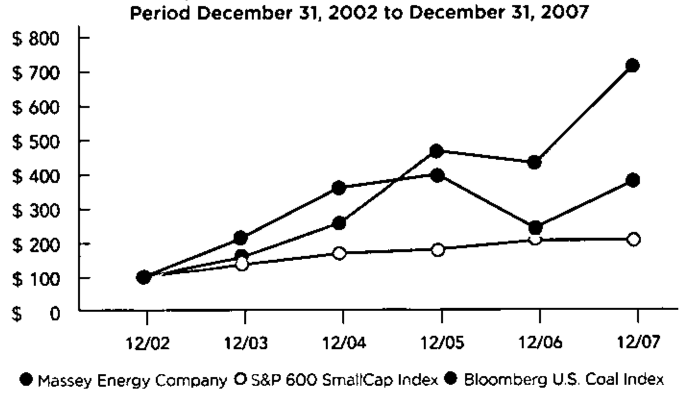
Investor E-Mail

Investor@masseyenergyco.com

Ethics Hotline

(888) 424-2417

Comparison of Cumulative Total Return for the Period December 31, 2002 to December 31, 2007



	12/02	12/03	12/04	12/05	12/06	12/07
Massey Energy Company	100.0	215.6	364.0	396.1	244.6	378.3
S&P 600 SmallCap Index	100.0	138.6	169.8	182.8	210.3	209.8
Bloomberg U.S. Coal Index	100.0	158.3	259.3	468.6	436.1	712.6

The graph above compares the performance of Massey Energy's common stock with that of the S&P 600 SmallCap Index and the Bloomberg U.S. Coal Index, a published industry index. The Company is included as a composite member of the S&P 600 SmallCap Index and the Bloomberg U.S. Coal Index. The historical data provided above for both the S&P 600 SmallCap Index and the Bloomberg U.S. Coal Index comes from Bloomberg Professional Service and is based on the current composition of each respective index.

Stock Price and Dividend Information

Stock price as of December 31, 2007 was $35.75:

	2007		
Quarter	High	Low	Dividend
First	$26.35	$21.55	$ 0.04
Second	$30.73	$23.97	$ 0.04
Third	$26.80	$16.01	$ 0.04
Fourth	$37.99	$21.49	$ 0.05

Note Regarding Forward-Looking Statements

This annual report and the Form 10-K included herein contain forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995.

We caution readers that forward-looking statements and similar statements are subject to certain risks, trends and uncertainties that could cause actual cash flows, results of operations, financial condition, cost reductions, acquisitions, dispositions, financing transactions, operations, expansion, consolidation, and other events to differ materially from the expectations expressed or implied in such forward-looking statements. Any forward-looking statements are also subject to a number of assumptions regarding, among other things, future economic, competitive and market conditions. Such forward-looking statements are based on facts and conditions as they exist at the time such statements are made as well as predictions as to future facts and conditions, the accurate prediction of which may be difficult and involve the assessment of events beyond the Company's control. We disclaim any obligation to update these forward-looking statements unless required by securities law, and we caution the reader not to rely on them unduly. We have based any forward-looking statements we have made on our current expectations and assumptions about future events and circumstances that are subject to risks, uncertainties and contingencies that could cause results to differ materially from those discussed in the forward-looking statements. We refer you to page "i" of the Form 10-K included in this annual report for a description of such items.

Additional information concerning these and other risks, uncertainties and contingencies can be found in press releases as well as Massey Energy's previous public periodic filings with the Securities and Exchange Commission. Such filings are available either publicly, under the Investor Relations page of Massey Energy's website: www.masseyenergy.com, or upon request from Massey Energy's Investor Relations Department: (866) 814-6512.

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Massey Energy®

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RICHMOND, VA 23261
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