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U.S. Coal: A Primer on the Major Issues

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U.S. Coal: A Primer on the Major Issues

Summary

The U.S. coal industry has gone through a number of gradual shifts in recent decades. The industry has become more concentrated, and mine productivity has improved. More low-sulfur coal and less high sulfur coal is today being produced. Less coal is exported, in part because of a strong U.S. dollar. Improved production methods, such as greater utilization of and improvements in longwall mining technology, have lowered the cost of underground mining, although surface mining continues to hold a substantial cost advantage.

The United States is well endowed with coal. The total demonstrated resource base is estimated by the Energy Information Administration (EIA) at 508 billion short tons, of which about 274 billion short tons are classified as recoverable reserves. U.S. recoverable reserves are estimated at 25% of total world reserves. Production of U.S. coal reached an all-time high in 2001 at 1,121 million short tons.

Coal supplies 22% of the nation's energy demand but 52% of its electricity needs. EIA forecasts coal to fall to 47% of the U.S. electricity market by 2025 because of increased competition from natural gas. About 1,063 million short tons of coal were consumed in the United States in 2001, 90% of which was used in the electric power sector. Currently, railroads move about 65% of all coal, barges transport about 15%, and trucks about 11%.

State agencies play a large role in regulating the coal industry, often exercising authority delegated by federal agencies pursuant to federal environmental and safety laws. The Surface Mining Control and Reclamation Act (SMCRA) established the bulk of the guidelines for coal mining and created the Office of Surface Mining in the Department of the Interior. Other federal agencies regulate mining safety, air and water emissions, and other aspects of coal production and use.

Air emissions and mountaintop mining are the most important environmental issues currently affecting the coal industry. Coal-fired electric generating facilities are a major source of air emissions, including sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), mercury, and carbon dioxide (CO_2). Regulations under the Clean Air Act (CAA) limit SO_2, NO_X, and PM emissions, with further requirements on the horizon. CO_2, a greenhouse gas associated with potential climate change, however, is not controlled under the CAA. The practice of mountaintop mining – removing the top of a mountain to reveal underlying coal seams – has received considerable attention recently. When mountaintop material is deposited in adjacent valleys, streams flowing through the valleys are buried.

The outlook for U.S. coal is mixed. While forecasts predict steady growth in coal supply and demand, the increased production is expected to come from fewer, larger mines and fewer producers. Continued competition from natural gas is likely to put pressure on coal prices for the foreseeable future.

This report will not be updated.

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U.S. Coal: A Primer on the Major Issues

Introduction

In recent decades, the U.S. coal industry has been changing significantly. Coal production has shifted from high-sulfur to low-sulfur. The number of coal mining firms has decreased, while the size of the average mine and labor productivity have increased. Driven by strong demand from electric power plants – coal's primary customer – coal production has risen steadily. However, natural gas has been the recent fuel of choice for new power plants, eroding coal's market share.

The United States is well endowed with coal. The Energy Information Administration (EIA) estimates there are about 274 billion tons of recoverable domestic coal reserves. The total demonstrated resource base (DRB)[1] is estimated at 508 billion tons.[2]

However, a number of constraints affecting the mining and use of coal – including air and water pollution controls and health and safety requirements – may limit just how much of this resource potential is ultimately realized.

Regulation of air emissions is one of the most controversial and longstanding coal issues. Coal-fired plants emit a variety of pollutants, including sulfur dioxide, nitrogen oxides, mercury, and particulate matter. Coal combustion is also a major source of carbon dioxide, which may play a role in global climate change.

Water pollution issues are also a subject of debate, particularly the practice of mountaintop mining – removing the top of a mountain to reveal underlying coal seams. A federal district court in West Virginia ruled in May 2002 that depositing mountaintop material in adjacent stream valleys violated the Clean Water Act. However, in January 2003, the 4th Circuit Court of Appeals in Richmond, Virginia, overturned district court decision.[3] No appeal has been filed.

The amount of research and development (R&D) for new coal technology is important to the industry, especially efforts to develop cleaner combustion systems

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1 The demonstrated resource base is the sum of coal in both the measured (proven) and indicated resource categories. The DRB represents that part of the identified coal resource from which reserves are calculated.

2 U.S. Department of Energy (DOE), Energy Information Administration (EIA), *Coal Industry Annual, 2001*

3 *Kentuckians for the Commonwealth v. Corps of Engineers*, S.D.W.Va., No. 2:01:0770, 5/08/02; *Kentuckians for the Commonwealth v. Rivenburgh*, No. 02-1736; and *Pocahontas Development Corp. et al v. Rivenburgh*, No. 02-1737, CA4, 1/29/03.

and other technologies for reducing coal's environmental impact. Alongside federal R&D programs are tax incentives contained in Title 29 of the Internal Revenue Code to encourage synthetic fuel development and clean coal technology. Mine safety, health, and environmental questions are being addressed through the Black Lung Fund and the abandoned mine reclamation fund.

This report is intended to be a primer on the role of coal in the U.S. energy picture and on the issues noted above, particularly mountaintop mining and clean air compliance. Some of these issues are discussed in greater detail in separate CRS reports.

Energy Trends

Out of the four major U.S. fuel sources – oil, natural gas, coal, and uranium – coal has the largest domestic reserve base and the largest share of U.S. energy production in Btus. A far smaller percentage of U.S. coal demand is met by imports than for the other major fuels. EIA projects that coal imports will continue to be negligible through 2025, while other major fuels will see a growing reliance on foreign sources, and that coal will continue to be the largest source of domestic energy production.[4]

Production of coal in the United States reached an all-time high of 1,128 million short tons in 2001, although it dropped slightly in 2002. Coal production accounted for 33% of total U.S. energy production in terms of Btu value in 2001. In EIA's 2025 forecast, coal accounts for about the same share – 32.6%. Annual coal consumption is forecast to gradually rise, increasing by 400 million short tons between 2001 and 2025. In 2025, over 90% of coal will likely be used in the electric power sector, as it is today. Domestic mines will continue to meet the overwhelming majority of U.S. coal demand, with imports remaining below 2%, according to the EIA projections. U.S. coal exports are currently about twice the level of imports but are projected by EIA to steadily lose world market share.

U.S. natural gas production is projected to increase by 1.3% annually through 2020 – from 19.5 trillion cubic feet (tcf) to 25.1 tcf, according to EIA. With annual consumption estimated to reach 33 tcf, natural gas imports of about 8 tcf will be needed to fill the gap – about 25% of consumption. The gap is expected to be met primarily with imports from Canada. Net imports of natural gas currently are about 3.7 tcf, or 16%, of demand. EIA projects that natural gas will rise from 27% of U.S. energy production in 2001 to 30% in 2025.

U.S. oil production is expected to increase slightly, from 8.9 million barrels per day (mbd) to 9.4 mbd in 2025. Net oil imports are expected to grow from 55% of demand in 2001 to 68% by 2025. Total U.S. petroleum demand is expected to grow at 1.7% annually through 2025, reaching 29.2 mbd. The transportation sector will continue to account for 74% of petroleum end use – which is expected to be 21.6 mbd.

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[4] U.S. DOE, EIA, *Annual Energy Outlook, 2003*, January 2003.

Energy production from nuclear power is projected to be flat, while energy from renewable sources, including hydropower, is expected to increase by about 2.2% annually. Renewables are forecast by EIA to grow from 5.5% of U.S. energy consumption in 2001 to 6.3% in 2025.

Cycle of Coal Utilization

Two-thirds of U.S. coal comes from surface mines, while the remaining one-third comes from deep underground mines.[5] For underground mining, the most efficient technique is the longwall method, which employs a large machine with a rotating drum that moves back and forth across a wide coal seam. Once coal is removed by a longwall miner or other method, it is then moved out of the mine with conveyor belts or shuttle cars.

Surface mining, also called "open-pit" or strip mining, entails blasting rock above the coal with explosives. This overburden rock is then removed with huge electric shovels and draglines to reveal the coal seam. The coal seam in a surface mine is worked in long cuts by uncovering and removing coal then backfilling and reclaiming land in sequence. In other words, while coal extraction is taking place, as required by federal law, the reclamation work occurs in an adjacent area previously mined.

After being mined, some coal[6] goes through a cleaning prep facility, where it is cleaned and separated by grades. Cleaning upgrades the quality of the coal by removing some of the impurities such as rock, clay, and other ash-producing material. In general, 30 tons of refuse are removed for every 100 tons of raw bituminous coal that is cleaned. This refuse is generally pumped into an impoundment area often built near old underground mines in steeply sloping valleys.

Once cleaned and separated, if necessary, the coal is stockpiled and shipped to the customer by rail, barge, truck or conveyor. It usually takes more than one mode of transport for coal to reach its final destination.

Utilities burn pulverized coal to produce high-pressure steam that powers an electric generator. The pulverized coal, burned at about 1,400 degrees centigrade (depending on the boiler design), has a higher rate of combustion than non-pulverized coal. This high heat converts water in tubes lining the boiler into steam. The high pressure steam passes through a turbine, causing the turbine shaft to rotate at high speed and turn an electric generator. The electricity is transformed into high voltages for long distance transmission, then near the point of consumption converted back to a lower, safer voltage (**see figure 1**). About 500 out of the 3,000 power plants in the United States burn coal.

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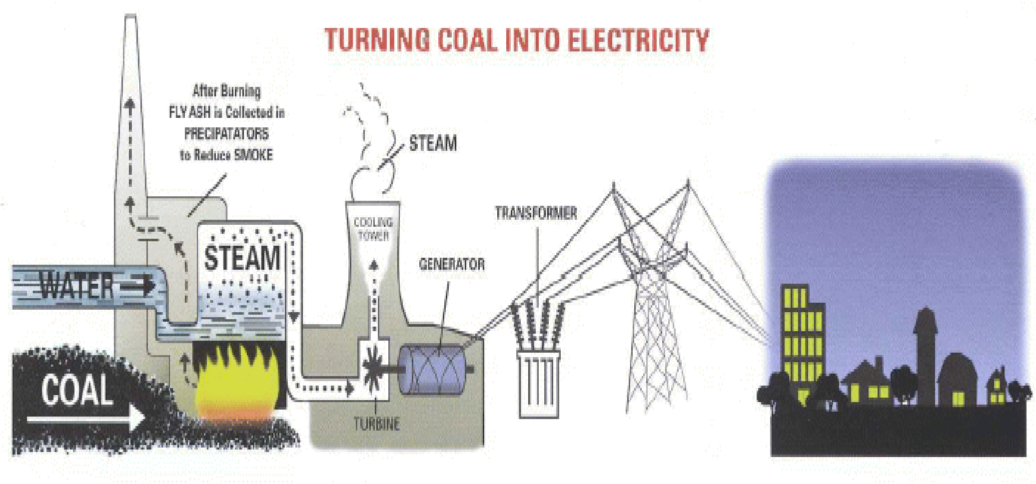
[5] Another type of mining, called "steep slope" mining, has largely been superseded by "mountaintop removal mining" discussed in a later chapter.

[6] About half of bituminous coal is cleaned, while subbituminous coal generally is not (see definitions in the next section).

Figure 1. Turning Coal into Electricity



Source: *Facts About Coal and Minerals,* National Mining Association (NMA), May 2002

As coal is burned, emissions are produced that contain sulfur dioxide, nitrogen oxides, carbon dioxide, particulate matter, ash, and mercury. A discussion on coal combustion emissions is found in the Environment, Health and Safety section of this report.

Coal Supply and Demand[7]

Resources and Reserves

Coal – a dense carbonaceous fossil fuel – is formed from decayed organic matter that has been subjected to various temperatures and pressures without the presence of oxygen. This burnable carbonaceous rock also contains various amounts of mineral matter. Coal seams are formed along with other sedimentary rocks, primarily sandstone and shale.

There are four basic types of coal throughout the United States:

1. Lignite: a brownish-black coal with relatively high moisture and ash content and relatively low heating value. Lignite is mined in Texas, North Dakota, Louisiana, and Montana.

2. Subbituminous: This is a dull black coal with higher heating value than lignite and used for generating electricity and space heat. Resources are found in Montana, Wyoming Colorado, New Mexico, Washington, and Alaska.

[7] Prepared by Marc Humphries, CRS Resources, Science, and Industry Division.

3. Bituminous (soft coal): This type of coal has a higher heating value than subbituminous and lignite and is the type typically used for electric power generation in the United States. It is found primarily in Appalachia and the Midwest

4. Anthracite (hard coal): Anthracite has the highest energy content of all coals but occurs in a limited geographic areas, mainly in Appalachia and Pennsylvania.

Coal quality is measured by its Btu (energy) value, sulfur levels, and ash content. The content of sulfur is significant because of the sulfur dioxide (SO_2) emissions that occur during coal combustion. There are controls on the amount of SO_2 allowed from coal-fired power plants.

U.S. Coal Reserves. The U.S. demonstrated reserve base for coal is estimated at 508 billion short tons, but as much as 45% is considered to be unrecoverable. Thus, accessible reserves are estimated at about 274 billion short tons. EIA statistics show that more than half of U.S. coal reserves are located in the West (see **Table 1**).

Table 1. U.S. Coal Reserves by Region

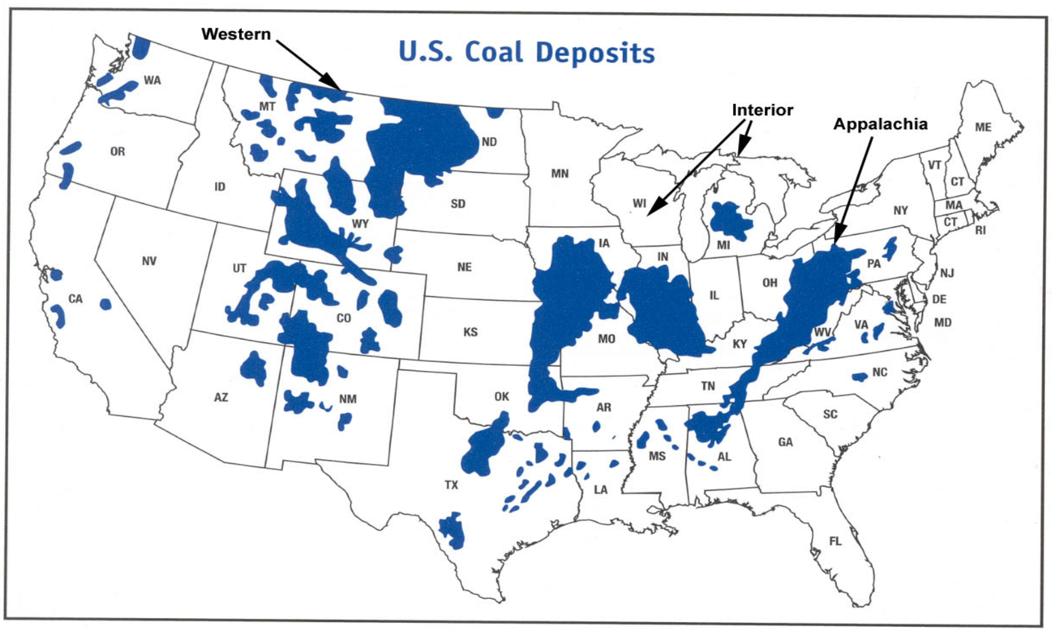
Coal-Producing Region	Million Short Tons	% of Total
Surface		
Appalachia	16,518.1	13.4
Interior	27,261.2	22.1
West	79,145.5	64.3
U.S. Total	122,924.9	100.0
Underground		
Appalachia	39,630.9	26.2
Interior	37,491.6	24.8
West	73,865.5	48.9
U.S. Total	150,988.0	100.0
Total		
Appalachia	56,149.1	20.4
Interior	64,752.8	23.6
West	153,011.0	55.8
Total U.S.	273,912.9	100.0

Source: Energy Information Administration., U.S. Coal Reserves, A Review and Update, 1995Tables may not add due to rounding.

The breakout of the demonstrated reserve base (DRB) by sulfur content (low, medium, high)[8] is fairly even. Low-sulfur coal is estimated by EIA at 170.8 billion short tons (b st); medium 141.1 b st; and high at 183.7 b st. The location of the various coals is not evenly divided, however. Eighty-four percent of the low-sulfur coal is in the West, 15% in Appalachia, and only 1% in the Interior region. Conversely, the Interior states contain 69% of all the high-sulfur bituminous coal, Appalachia 25%, and the West only 7%. **Figure 2** shows the major U.S. coal-producing regions.

The United States ranks number one in the world in recoverable coal reserves. Russia has an estimated reserve base of 173 billion short tons, while China has 150 billion short tons. Taken together, the top three countries hold 55% of the world's recoverable coal reserves. U.S. recoverable coal reserves represent about 25% of total world reserves. Russia holds 16%, and China 14%. When India and Australia are added, the top five countries account for 71% of world coal reserves (see **Table 2**).

Figure 2. U.S. Coal Deposits



Source: National Mining Association

On a statewide basis, Montana and Illinois rank one and two for demonstrated reserve base of coal (see **Table 3**), but when looking at accessibility and recovery factors, a different picture emerges. In Illinois, whose entire demonstrated resource base (see footnote 1) is bituminous, 82% is underground; the state's accessibility factor[9] for underground coal is 67%, and its recovery factor is 50%. This would

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[8] A low sulfur level is 0.60 lbs. or less sulfur per million Btus; medium sulfur level is 0.61-1.67 lbs per million Btus; a high sulfur level is 1.68 lbs or more sulfur per million Btus.

[9] The accessibility factor is the amount of the demonstrated coal reserve base (surface and
(continued...)

indicate relatively low estimated recoverable reserves from the DRB. Overall, the Interior region, with its high-sulfur, primarily underground coal, drops from a DRB of 145 billion short tons to 65 billion recoverable short tons – or from 29% to 23% of the total reserve base. The entire Interior region is a mature producing region that appears to have reached its production peak.[10]

Table 2. World Coal Reserves
(million short tons)

Country	Reserves	% of Total
United States	274	25.0
Russia	173	16.0
China	150	14.0
Australia	99	9.0
India	83	7.0
Other	310	29.0
Total World Reserves	1,089	100.0

Source: Department of Energy, Energy Information Administration, International Energy Outlook, 2002.

Table 3. U.S. Coal Demonstrated Resource Base, Top 5 States
(in million short tons)

State	Underground	Surface	Total
Montana	71.0	48.7	119.7
Illinois	88.5	16.6	105.1
Wyoming	42.5	25.3	67.8
West Virginia	31.0	4.4	35.4
Kentucky	18.6	13.5	32.1
All Others	90.2	57.4	147.6
Total DRB	341.8	165.9	507.7

Source: Energy Information Administration., Coal Reserve Data.

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[9] (...continued)
underground) that is considered accessible for future development. This term is discussed in the EIA document *U.S. Coal Reserves: A Review and Update*, p. 37.

[10] Milici, Robert C., U.S. Geological Survey, *Production Trends of Major U.S. Coal-Producing Regions*, Pittsburgh Coal Conference 1996.

In the West, the accessibility rate is much higher: 90% for western Montana and 98% for Wyoming. However, the recovery rate is a major limiting factor in Montana coal production, given that 60% of its DRB is underground. Even though its accessibility is high at 90%, Montana has a recovery factor of 56%.[11] Coal reserves in the Powder River Basin (PRB) in Wyoming are enormous.

Coal Production Trends

U.S. coal production of 1,127.7 million short tons in 2001 set a new record, although it fell slightly in 2002. Production has fluctuated over the past 10 years (1992-2001) between about 1 billion short tons annually to 1.1 billion short tons (see **Table 4**). Overall, this indicates relatively flat production since 1992.

However, important changes are taking place in the share of Eastern coal versus Western, low-sulfur coal. The production trend of eastern Appalachian coal is slightly downward from recent high levels in 1997-98 (see **figure 3**). In 1997, Western production surpassed coal production from Appalachia. Production from the Interior states also showed an overall decline during the past several years.

Table 4. U.S. Coal Production
(million short tons)

Year	Total Coal Production
1992	997.5
1993	945.4
1994	1,033.5
1995	1,033.0
1996	1,063.9
1997	1,089.9
1998	1,117.5
1999	1,100.4
2000	1,073.6
2001	1,127.7
2002	1,099.9

Source: Monthly Energy Review, DOE/EIA, January 2003, and Mining Engineering, May 2002.

[11] EIA, U.S. Coal Reserves, 1995.

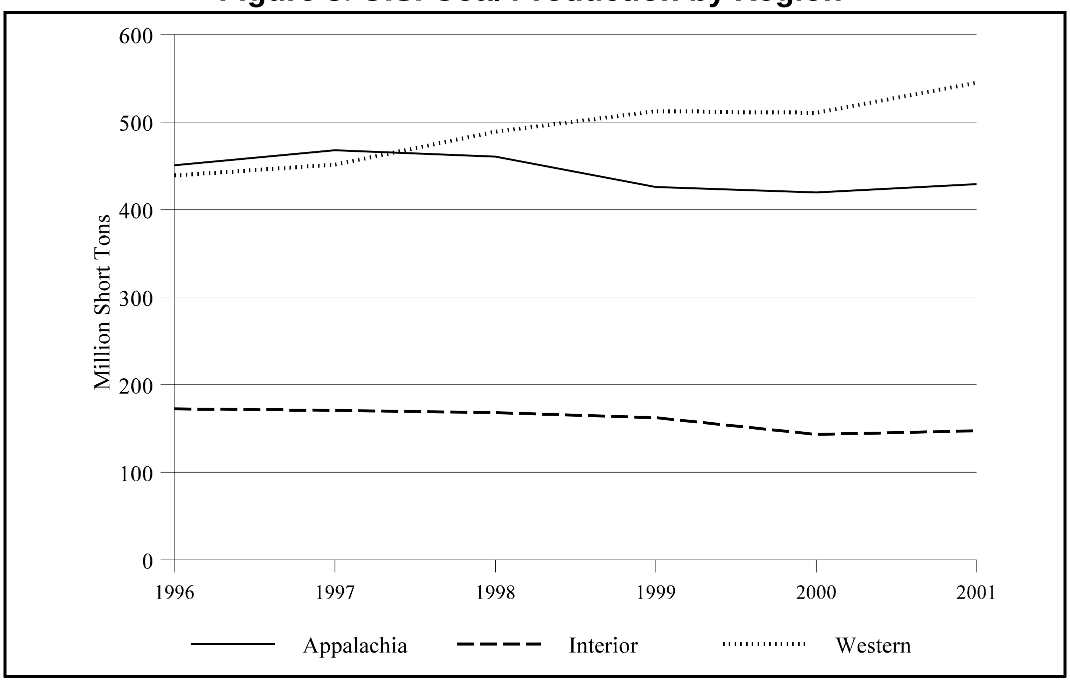
Most of the Western producers operate surface mines, in contrast to the larger number of underground mines in the Interior and Eastern regions. Surface mining operations accounted for 65% of total mine output in 2001, compared with about 61% of output in 1996. Declining production in Interior states is evident, while production in Western states, Wyoming in particular, has increased at 4.8% annually over the past decade. Appalachian production, while up in 2001, has been declining at an average rate of 1.4% annually for the last 10 years.

The leading coal-producing states are Wyoming (365.6 million short tons, hereafter m st) and West Virginia (160.4 m st). In 2001, they accounted for 47% of total U.S. production. Kentucky, the third-largest producer, contributed 132.1 m st.

Coal production in the United States is projected to continue to rise, reaching 1,440 million short tons by 2025, up from the current production level of 1,121 million short tons. While some increases in low-sulfur coal production occur in Appalachia, most of the low-sulfur coal production is expected to occur in the West.

Spurred partly by the Clean Air Act, production of low-sulfur coal – particularly Western coal, the lowest in sulfur – is projected to rise from about 600 million short tons in 2001 to about 900 million short tons in 2025. In contrast, production of Eastern coal is projected to remain nearly flat through 2025, according to EIA. The annual growth rate for Western coal is expected to be 1.7% through 2025.

Figure 3. U.S. Coal Production by Region



Source: EIA, *Coal Industry Annual, 2000*, January 2002.

Coal Production on Federal Lands

U.S. government-owned lands hold about 60% of U.S. recoverable coal reserves. The federal coal leasing program is administered by the Bureau of Land Management (BLM) under the authority of the Mineral Leasing Act of 1920, as amended, and the Mineral Leasing Act for Acquired Lands of 1947. BLM is responsible for coal leasing on roughly 570 million acres of federal lands as well as on private lands where mineral rights are owned by the federal government.

Regulatory guidance for BLM's leasing program is contained in Title 43 of the Code of Federal Regulations (CFR), part 3400. BLM conducts competitive coal lease sales either through a regional leasing process or a leasing-by-application process. Once "fair market value" is established, sealed bids are accepted prior to the sale date. Eligible bids must meet or exceed the fair market value of the coal tract as determined by BLM, and include necessary fees, e.g., upfront rental payments and a portion of the bid amount. Permits and licenses to mine must still be acquired from BLM, the Office of Surface Mining (OSM), and state and local governments.

Coal leases on federal lands awarded after the Coal Leasing Act of 1976 pay royalty rates of 8% of the value of production from underground mines and 12.5% of the value of production from surface mines. Annual rental fees are $3 per acre. Before a lease is issued the lessee must post a financial guarantee or bond sufficient to cover the costs of reclamation and other provisions of the lease agreement.

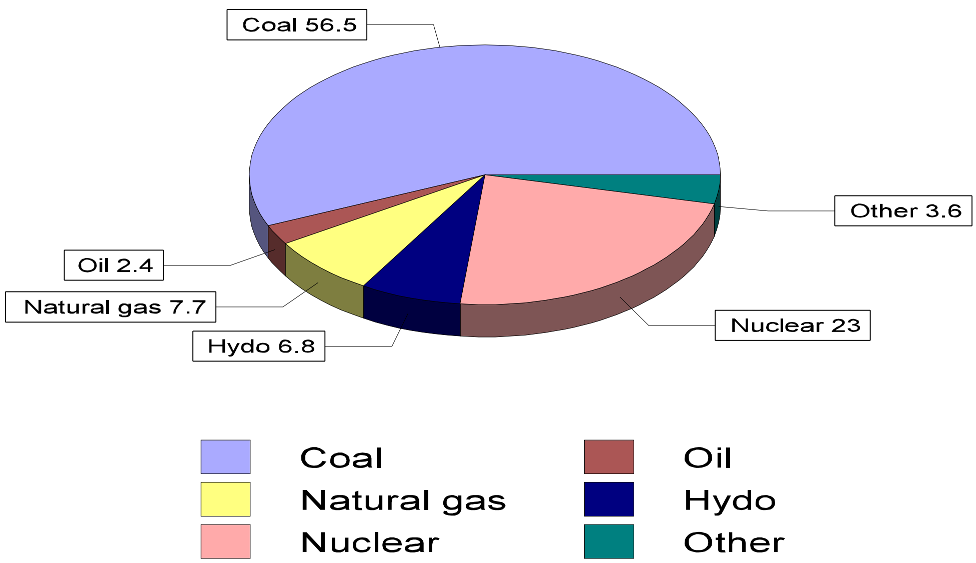
Coal production on federal lands was 393.5 million short tons in 2001, or 35% of all U.S. production. A record 411.8 million short tons of coal was produced on federal lands in 2000. This is up from 253 million short tons in 1991. Royalty payments have fluctuated widely over the last 10 years and reached $337.7 million in 2001, up from $276.7 million in 1991.

Coal Consumption Patterns

Coal supplies 22% of U.S. energy demand but 56% of the energy used by the electric power sector (utility and non-utility consumption). Total U.S. coal consumption was 1,063 million short tons in 2001, with 91% of coal used in the electric power sector. The other end-use sectors, accounting for the remaining 9% of coal consumption, include other industrial (5%), coke plants (2.5%), and residential/commercial (1.5%).

Coal consumption has maintained a greater than 50% share of the electric power sector for many years (see **figure 4**). Although total coal consumption for electricity generation is predicted to rise, coal's share of electric power generation will fall below 50% by 2025, according to EIA. Demand for coking coal for steelmaking is expected to decline from about 25 m st to 17 m st, because increased steel production is coming from minimills that do not use coke. EIA forecasts coal consumption to rise from 1,063 m st in 2001 to 1,444 m st in 2025. Over the same period, EIA predicts a drop – from 22% to 20% – in coal's overall share of U.S. energy demand.

Figure 4. U.S. Electric Power Sector Energy Consumption, 2001 (%)



Source: National Mining Association, *Facts About Coal and Minerals*, 2002.

Coal Prices

Coal price statistics generally refer either to prices at the mine or to delivered prices to consumers (typically electric utilities). Up to half of the price of coal delivered to customers can consist of transportation costs.

Transportation costs also have a strong effect on the price charged at the mine – the greater the distance from major markets, the less valuable a coal deposit becomes. Along with transportation, other major factors affecting coal prices are:

- production costs, determined by the nature of a coal deposit and the extraction method employed (i.e., surface versus underground mining);
- energy content of the coal (Btus per ton – the greater the Btu content, the more valuable the coal);
- sulfur content – the lower the sulfur content, the more valuable the coal;
- land fees, for purchase or lease, including fees for mining on federal lands;
- state and other taxes; and
- profit.

Western coal tends to be lowest in sulfur, but it also has relatively low Btu content and is farthest from most major electricity markets. However, the production costs at large Western surface mines are relatively low, which allows Western coal to compete very effectively even with higher-Btu Eastern coal that doesn't have to be transported as far. The lowest-quality Western coal, which is generally not economic to transport significant distances, is often consumed at electric power plants at mine locations. Mine prices[12] for coal produced from surface mining operations averaged $12.46 per short ton in 2000. Underground mine prices were nearly double at $24.73 per short ton.

Average coal prices at the mine have generally declined from $21.49 per short ton in 1991 to $16.78 per short ton in 2000.[13] Price differentials between Western and Eastern coal are substantial. Mine prices in the West average $8.73 per short ton, while coal prices in Appalachia are near $26 per short ton. Interior prices fall between the two at $18.37 per short ton. Price data, when further broken out by state, show Wyoming prices falling from $8.09 per short ton in 1991 to $5.50 per short ton in 2000. EIA projects that average mine prices will fall 0.87% annually through 2025.

Because of transportation costs, customers farthest from major mining areas tend to pay the most for delivered coal. On average, electric utility customers paid $24.28 per short ton for delivered coal in 2000. But customers in New England paid the highest average price, at $40.16 per short ton, followed by South Atlantic customers, paying $34.81 per short ton. The average price of delivered coal to electric utilities is forecast by EIA to fall by 0.5% annually to $22.17 per short ton by 2025.

Coal Transportation

Railroads are the primary shipment mode for about 65% of all U.S. coal. About 15% is moved primarily by barge on inland waterways. Truck deliveries account for about 11% of all coal moved in the United States, and 8% is moved by conveyor belt or other systems.[14]

Transportation costs on average account for 41% of delivered coal prices, but EIA projects coal transportation costs to fall by 1.2% each year through 2025. Coal transport can account for as much as 60% of the delivered price of coal out of the Powder River Basin (PRB), although costs have been dropping. Transport costs are lower because of larger unit trains with high-capacity coal cars (100 tons or more), and improved rates and cycle times from Western coalfields. Between 1988 and 1997, the average rate per ton decreased by 35% for Powder River Basin coal while

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[12] Mine prices cited in this report are "freight on board" (FOB); that is, the coal has been loaded into a rail car or other conveyance for shipment.

[13] All prices are discussed in Platts RDI Consulting, *Coal Supply and Demand Fundamentals*, Carnegie Mellon University, November 25, 2002, nominal dollars.

[14] EIA, *Coal Industry Annual 2000.*

shipments jumped by 74%.[15] As production of Western coal increases, adequate rail capacity to Eastern markets, although improving, may become a growing concern.

Coal Trade

U.S. coal exports (both steam and coking coal) declined by 50% between 1997 and 2001 to 48.7 million short tons. This decline is likely to continue because higher-cost U.S. coal is generally becoming less competitive in foreign markets. EIA expects U.S. coal exports to drop from 7% of world coal trade in 2001 to 3% in 2015, despite increasing world demand, particularly in Asian markets. Major world exporters of steam coal are Australia, Indonesia, South Africa, and China.[16]

U.S. coal imports set a record in 2001, rising 58% from the previous year. However, the 19.8 million short tons imported in 2001 were less than half of U.S. exports and only about 2% of total U.S. demand. The sharp rise in imports resulted from tight supplies in the United States overall and a higher demand for low-sulfur coal. Imported coal at $34 per short ton is competitive with prices paid by consumers in the New England and South Atlantic regions. Electric utilities accounted for over 50% of imported coal. Colombia provided the United States with 57% of its coal imports in 2001, and Canada ranked second at 17%.[17]

Tax Incentives[18]

Coal is subject to one federal excise tax (the black lung excise tax) and one fee (Abandoned Mine Land Reclamation Fee), but it also qualifies for certain tax benefits: percentage depletion allowance (rather than cost depletion) and expensing (rather than capitalization) of mine development and exploration costs. The demand for coal has also been stimulated by favorable rulings from the Internal Revenue Service that allow coal that is ground, soaked, and cured to be defined as a "synthetic" fuel, thus qualifying for a tax credit under §29 of the IRS code. The credit for such synthetic fuel, which is primarily used as a boiler fuel, is approximately $26 per ton of coal, and is available through 2007 for facilities placed in service by June 30, 1998. The §29 credit was also available for coalbed methane through the end of 2002.

Also important to coal producers are proposals to subsidize the use of clean coal technologies. Both the House- and Senate-passed versions of comprehensive energy legislation in the 107th Congress (H.R. 4) would have provided an investment tax credit for capital equipment using clean coal technologies and a production tax credit

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15 DOE/EIA, *Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation,* October 2000.

16 Ewart, Ellen, "U.S. Coal Exports Don't Swing Much Anymore," *Coal Age,* January 2003.

17 Freme, Fred, "Coal Overview," *Mining Engineering,* May 2002.

18 Prepared by Salvatore Lazzari, Specialist in Energy Policy, CRS Resources, Science, and Industry Division.

for the electricity generated from facilities that use clean coal technologies. Although H.R. 4 was not enacted, similar proposals are possible in the 108th Congress.

Structure of the Coal Industry[19]

The U.S. coal industry is becoming more concentrated. Coal production from the top five producers jumped from 26% of total U.S. production in 1991 to 51% in 2001 (see **Table 5**). The top two producers in 2001, Peabody Energy and Arch Coal, were responsible for 27.9% of all U.S. production.

The 10 largest-producing mines – nine of which are in Wyoming – accounted for 28% of U.S. production in 2000. The top 10 mines and all but two of the 20 largest mines are surface mines. The three leading producers in Wyoming are Peabody Energy (99.2 m st), Kennecott Energy (77.4 m st), and Arch Coal (60.6 m st). In the second-leading coal producing state of West Virginia, the top three producers are Consol Energy (17.9 m st), Arch Coal (16.7m st), and Peabody Energy (9 m st). The top 10 producing mines in West Virginia accounted for 45% of the state's production and 5% of U.S. production in 2000.

Table 5. Major U.S. Coal Producers

(million short tons)

Year 2001 Producers	Tonnage	% of Total	Year 1991 Producers	Tonnage	% of Total
Peabody	194.4	17.3	Peabody	91.7	9.2
Arch Coal	118.4	10.6	Consol Coal	55.2	5.5
Kennecott Energy	117.5	10.5	AMAX Coal	44.8	4.5
Consol Energy	73.7	6.6	ARCO Coal	32.6	3.3
RAG American Coal	65.5	5.9	Exxon Coal	31.5	3.2

Source: Coal Industry Annual, 1993 for 1991 data. NMA Facts About Coal and Minerals, 2002 for 2001 data.

This trend toward consolidation is likely to continue, because the smaller operations with higher-cost coal in the East are becoming less competitive. Low-cost coal plus lower transportation costs is expected to allow more Western coal to penetrate eastern markets.

The concentration of production in the industry is not expected to have any upward price effects, as price forecasts by EIA generally decline over the next 25 years. For example, in 2001 dollars, mine prices are projected to fall an average of 0.8% annually through 2025 (another $3.23 per ton). In nominal, unadjusted dollars,

[19] Prepared by Marc Humphries, Analyst in Energy Policy, CRS Resources, Science, and Industry Division.

the average price of coal at the mine is forecast to climb from $18.83 in 1995 to $26 in 2025. Western coal prices are projected to remain less than half of Eastern coal prices.

While coal production is climbing, the number of mines is declining and will likely continue to decline in the future. The number of mines producing more than 10,000 short tons per year dropped from 4,092 in 1987 to 1,453 in 2000. The mines that remain are producing more on average and using less labor to do it. The number of coal miners fell from 83,462 in1996 to 70,000 in 2000, and tons per worker-hour rose by 21% (**see Table 6)**. The decline was about 2% per year from 1970-2000. The reduction in mining employment is not expected to be as dramatic over the next 20 years, but the decline is expected to continue by an average of 0.5% each year.[20]

Labor costs relative to the value of coal production have dropped from 23% of mine production value in 1990 to 16% in 2001. EIA expects labor costs as a share of mine value to fall to 13% by 2025.

Table 6. Mine Productivity

Year	Number of Mines Producing More Than 10,000 short tons/year	Number of Workers	Tons/Average Man Hour
1992	2,746	110,196	4.36
1993	2,475	101,322	4.70
1994	2,354	97,500	4.98
1995	2,225	95,700	5.20
1996	1,903	83,462	5.69
1997	1,828	81,516	6.04
1998	1,726	85,418	6.20
1999	1,591	78,723	6.61
2000	1,453	71,522	6.91

Source: 1997, 2002 Keystone Coal Industry Manual, EIA Coal Industry Annual, 2000

Financial Health of the Industry

The financial status of the coal industry is difficult to determine because financial data is not readily available from many companies. However, EIA provides return on investment (ROI) data from its Financial Reporting Service (FRS). ROI figures on the coal industry indicate a general picture of mostly positive financial

[20] AEO, 2003, p. 87.

results. The industry averaged about a 7% ROI over the years 1992-2001, including a 26.4% return in 1998 but only a 1.7% return in 2000.[21]

Behind the average results, a much more mixed financial picture unfolds. For example, three major coal producers are under Chapter 11 bankruptcy protection, several companies have discontinued operations, and others are in financial difficulty. These financially troubled companies are primarily in Appalachia and the Interior regions. Because of widespread financial weakness in the industry, there is relatively little capital investment for infrastructure or new mines, according to industry analysts.[22]

Federal Agencies and Coal[23]

In conjunction with the states, federal agencies play a major role in regulating coal mining in the United States, as well as implementing environmental laws that affect coal. Below is a list of federal agencies that regulate the U.S. coal industry and programs that are relevant to the industry.

Office of Surface Mining

The Office of Surface Mining in the Department of the Interior (DOI) administers the Surface Mining Control and Reclamation Act of 1977 (SMCRA, 30 U.S.C. 1201 *et seq.*). The Office of Surface Mining oversees state programs that meet federal requirements, or it is the primary regulator in states without approved programs. The Act requires state or federal permits for surface mines and for the surface operations of underground mines, as well as a process for determining areas not suitable for coal mining. A reclamation plan is required for each mine, including a detailed timeline for reclaiming the land. Surface miners must also meet all applicable environmental regulations and performance standards. Performance bonds and financial guarantees must be sufficient to cover the costs of reclamation.

Mine Safety and Health Administration

The Mine Health and Safety Administration (MSHA) of the Department of Labor (DOL) is the primary regulator under the Federal Mine Safety and Health Act of 1977 (the Mine Act, 30 U.S.C. 801 *et seq.*). The Mine Act amended the 1969 Coal Act and consolidated all federal health and safety regulations of the mining industry into a single statutory system. The Mine Act transferred responsibilities from DOI to DOL and established MSHA. The Act also established an independent Federal Mine Safety and Health Review Commission to review MSHA's enforcement actions. The 1977 Mine Safety and Health Act included provisions of the 1969 Coal Act that prescribed mandatory health and safety standards and provided Black Lung benefits.

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[21] EIA, Performance Profiles of Major Energy Producers, Appendix B, January 2003.

[22] Ewart, *op. cit*.

[23] Prepared by Marc Humphries, Analyst in Energy Policy, CRS Resources, Science, and Industry Division.

Environmental Protection Agency

The Environmental Protection Agency (EPA) administers the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, and other major environmental laws that affect coal production and use. Under the Clean Air Act, EPA sets and enforces performance standards for large new or modified stationary sources, such as power plants, to ensure air quality standards. Provisions of the Clean Water Act require that each state develop and implement a comprehensive water quality management plan, subject to approval of EPA.

Other Federal Agencies

The Army Corps of Engineers issue permits for disposal of solid wastes, dredge, or fill material in navigable waters. The U.S. Geological Survey conducts coal resource assessments throughout the United States. The Bureau of Land Management administers the federal coal leasing program. The Minerals Management Service collects and distributes revenues from royalty, rent, and bonus bids from the leasing and production of coal on federal lands. The federal government continues to promote clean coal strategies through R&D funding at the Department of Energy.

Environment, Health, and Safety

Regulation of Air Emissions[24]

Beginning with the Clean Air Act of 1970, and with substantive additional measures enacted in amendments of 1977 and 1990, electric utilities have been subjected to a multilayered patchwork of air pollution emission requirements. Coal-fired electric generating facilities are major emitters of several gases (see **Table 7**), with clean air controls currently directed at three pollutants: sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM).

Table 7. 1999 Emissions From U.S. Fossil-fuel-fired Electric Generating Plants
(thousands of short tons)

	Coal	Petroleum	Natural Gas
SO_2	11,295	670	2
NOx	6,547	123	376
CO_2	1,900,304	91,753	198,655

Source: Energy Information Administration, *Electric Power Annual 1999* Volume II, p. 42.

[24] Prepared by Larry Parker, Specialist in Environmental Policy, CRS Resources, Science, and Industry Division.

Sulfur oxides have health effects and are a major contributor to acid rain and visibility impairment. Nitrogen oxides have direct health effects, contribute to acid rain and visibility impairment, and are a precursor to ozone, a primary constituent of smog. Particulates have health effects, with the smallest particles now thought to be serious causative agents; current regulations focus on particles 10 microns in size or smaller (PM_{10}) and proposed regulations would control particles less than 2.5 microns in diameter ($PM_{2.5}$).[25] Emissions of SO_2 and of NOx contribute to the formation of these very fine particles. In 1999, according to EPA, electric utilities accounted for approximately 67% of U.S. emissions of SO_2, 25% of NOx, and 11% of PM_{10}. Most of those emissions were from coal-fired facilities.

In addition, fossil fuel fired electric generating facilities produce two other gases of environmental and health concern: mercury (Hg) and carbon dioxide (CO_2). While some sources of mercury are currently regulated, emissions from electric utilities are not. However the Clean Air Act Amendments of 1990 designated Hg as a hazardous air pollutant subject to a regulatory regime spelled out in §112. A 1997 EPA study required by the act concluded mercury is a hazard to public health and found that electric utility steam generating units account for about one-third of the nation's mercury emissions.[26] On December 14, 2000, EPA announced its intention to regulate utility Hg emissions in 2004, with an effective date of 2007 or 2008.[27]

Carbon dioxide is a major greenhouse gas, and fossil fuel fired electric generating facilities account for about 36% of U.S. emissions. While CO_2 emissions are not currently regulated, the United States is a signatory of the United Nation Framework Convention on Climate Change, which involves a voluntary commitment to hold greenhouse gas emissions to 1990 levels. At present, U.S. emissions of CO_2 are running some 10% over that goal.[28] The United States signed the Kyoto Protocol, under which the U.S. would be legally committed to reduce emissions in the 2008-2012 period by 7% from a baseline that includes 1990 CO_2 levels; however, that Protocol has not been submitted to the Senate for advice and consent and is not in force. But it remains possible that, beyond the existing voluntary goal, utilities could be subjected to emissions limits on CO_2 at some time in the future.[29]

National Ambient Air Quality Standards – New Source Performance Standards – Lowest Achievable Emissions Rate. As enacted in 1970, the CAA established a two-pronged approach to protect and enhance the quality of the

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[25] 68 Federal Register 1660.

[26] U.S. Environmental Protection Agency, *Mercury Study Report*, EPA-452/R-97-003, December 1997.

[27] EPA, "Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units," *Federal Register*, Vol. 65, no. 245 (December 20, 2000), 79825-79831.

[28] John E. Blodgett and Larry Parker, *Global Climate Changes: Reducing Greenhouse Gases–How Much from What Baseline?* CRS Report 98-235 ENR. Updated Jan. 29, 2001.

[29] For a review of U.S. global climate change policy, see: Larry Parker and John Blodgett, *Global Climate Change Policy: Cost, Competitiveness, and Comprehensiveness*, CRS Report RL30024.

nation's air. First, the Act established National Ambient Air Quality Standards (NAAQS), which set limits on the level of specified air pollutants in ambient air. Second, the Act required national emission limits to be set for major new polluting facilities; these are called New Source Performance Standards (NSPS).

NAAQS have been established for six pollutants, including SO_2, NOx, and PM. Under the law, EPA sets primary NAAQS[30] to protect the public health with an "adequate margin of safety."[31] EPA periodically reviews NAAQS to take into account the most recent health data. NAAQS are federally enforceable with specific deadlines for compliance, but states are primarily responsible for actually implementing the standards, through development and enforcement of State Implementation Plans (SIPs). In general, these plans focus on reducing emissions from existing facilities to the extent necessary to ensure that ambient levels of pollution do not exceed the NAAQS. For example, EPA's recently promulgated NOx SIP Call requires 20 states and the District of Columbia to revise their SIPs to achieve substantial NOx reductions from their existing facilities to help ozone non-attainment areas in the Northeast comply with the ozone NAAQS.[32]

For areas *not* in attainment with one or more of these NAAQS, the 1970 CAA mandates states to require new sources to install Lowest Achievable Emissions Rate (LAER) technology. Along with offset rules, LAER ensures that overall emissions do not increase as a result of a new plant's operation. LAER is based on the most stringent emission rate of any state implementation plan or achieved in practice without regard to cost or energy use.[33] Existing sources in a non-attainment area are required to install Reasonably Available Control Technology (RACT), a state determination based on federal guidelines.

The 1970 CAA also established New Source Performance Standards (NSPS), which are emission limitations imposed on designated categories of major new (or modified existing) stationary sources of air pollution. For fossil fuel fired electric generating facilities, EPA has set NSPS for SO_2, NOx, and PM_{10}, and is required by the Act to review the standards every eight years. A new source is subject to NSPS regardless of its location or ambient air conditions.

In summary, under this overall regulatory regimen, existing sources in non-attainment areas are subject to controls determined by the state as necessary to meet NAAQS; existing sources are essentially free from controls in attainment areas. And

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[30] "Secondary" NAAQS, also nationwide standards, protect "welfare" values, such as visibility and agricultural productivity. There is no specific deadline for achieving secondary NAAQS.

[31] For a further discussion of NAAQS standard-setting, see: John Blodgett, Larry Parker, and James McCarthy, *Air Quality Standards: The Decisionmaking Process*, CRS Report 97-722 ENR.

[32] 63 Federal Register 57356.

[33] LAER may not be less stringent than NSPS.

major new sources, including fossil fuel fired electric generating facilities, are subject to NSPS as the minimum requirement anywhere.[34]

The requirement under the CAA to control SO_2, NOx and PM has increased the cost of coal-fired electric generation and affected the distribution of coal production around the country.[35] For example, the distinction between new and existing powerplants has resulted in existing facilities switching to lower sulfur coal over the past 30 years to control SO_2 in compliance with SIPs and the acid rain program under title IV. In contrast, the 1979 NSPS for SO_2 has put low- and high-sulfur coal on a more equal footing for new powerplant construction. Increased controls for NOx required by the 1998 NSPS for new sources and the NOx SIP for existing sources in the eastern United States will increase costs but have no influence on coal production distribution as SO_2 control did. Increased costs for existing coal-fired facilities are not anticipated to be sufficient to cause facilities to use natural-gas-fired facilities instead. However, for new facilities, the increased cost from the NOx NSPS widens the current cost advantage that new natural gas facilities have over new coal-fired facilities.

Multi-Pollutant Legislation. As noted above, coal-fired electric generating facilities are major sources of air pollutants and greenhouse gases. A patchwork of regulations to limit PM, SO_2, and NOx emissions exists, with further requirements on the horizon. The piecemeal nature of the regulations and the uncertainty of future requirements impose not only direct costs on utilities, but also make planning difficult in an environment already characterized by industry restructuring, volatile energy prices, and technological changes.

To bring some consistency and stability to the regulations affecting utility emissions, legislative initiatives have proposed a "multi-pollutant" strategy. Key elements of the strategy include:

- aligning pollution control processes and procedures for SO_2, and NOx so that both regulators and utility managers could anticipate requirements and integrate their decisions about how to control emissions;
- adopting efficient economic mechanisms – most notably "cap and trade" strategies – for the control of the pollutants;
- stabilizing requirements over time; and

[34] The federal focus on new facilities arose from several factors. First, it is generally less expensive to design into new construction necessary control features than to retrofit those features on existing facilities not designed to incorporate them. Second, uniform standards for new construction ensures that individual states will not be tempted to slacken environmental control requirements to compete for new industry.

[35] See Larry Parker and John Blodgett, *Electricity Restructuring: The Implications for Air Quality*, CRS Report 98-615, pp. 20-22.

- incorporating potential future control requirements for other emitted gases (e.g., Hg, CO_2 – a "four pollutant" strategy) into this more stable scheme.

This approach to controlling power plant emissions would have several tradeoffs. Overall, it would exchange regulatory and economic uncertainty for short- to mid-term certainty. For the environment, the current controversy that accompanies the setting of standards and the implementing of regulatory reduction requirements would be exchanged for a specific reduction target that would not change for 10-15 years. From an economic standpoint, implementing emission caps through emission trading would reduce costs, and the straightforward enforcement mechanism would also provide industry with certainty with respect to its responsibilities and potential penalties, and provide a consistent regulatory regime for industry planning. Finally, the program might open the door for simplifying or replacing elements of the current piecemeal requirements. On the other hand, cap and trade systems could conflict with health standards to protect local areas, as they would allow relatively high pollution in specific locations as long as the total emissions caps were not exceeded.

The overall impact on coal from a multi-pollutant strategy would depend on whether CO_2 were included, and how. The more modest the CO_2 reduction, the longer the compliance deadline, and the more flexible the compliance strategy, the less the impact. If a stringent program were enacted, such as would be needed for compliance with the Kyoto Protocol, the impact would be substantial. If CO_2 is not included, multi-pollutant legislation is not projected to greatly influence the overall production of coal for electric generation. However, a multi-pollutant bill could create an advantage for bituminous coal over subbituminous coal, depending on the specifics of the proposal, particularly with respect to Hg control. Generally, bituminous coal has a higher ionic mercury content than subbituminous, which has a greater elemental mercury content. Technology that would be used to control SO_2 ("scrubbers") and NOx (selective catalyst reduction) has the co-benefit of reducing ionic mercury, but much less effect on elemental mercury. Thus, using bituminous coal may save operators the expense of additional, dedicated Hg control. However, there are uncertainties, and insufficient work has been done to determine how much advantage may be involved here.

New Source Review. The Clean Air Act requires a preconstruction review of, and a permit for, almost any major modification of an air polluting source or any major new source. Assuming that a state has an EPA-approved State Implementation Plan (SIP), which spells out the state's strategy for complying with NAAQS, regulatory approval to construct the new source or modify the existing source must come from the appropriate state agency. To receive this "Permit to Construct," the applicant must show that the proposed source or modification will not result in, or exacerbate, violation of a NAAQS, either locally or downwind. In addition, applicants must show that their proposal will not result in local or downwind exceedences of increments of increased air pollution allowed under Prevention of

Significant Deterioration (PSD) regulations in areas complying with NAAQS. It is this preconstruction review process that is called New Source Review (NSR).[36]

The NSR process is triggered for any new source that potentially could emit 100 tons annually (or less in some areas) of any criteria air pollutant, and by any modification that will cause a significant increase in annual emissions (regulatorily defined as 40 tons for SO_2 and NOx[37]). The specific NSR requirements for affected sources depend on whether the sources involved are subject to the PSD or the non-attainment provisions.[38] If covered by PSD, the source is required to install Best Available Control Technology (BACT), which is determined on a case-by-case basis, and which cannot be less stringent than the federally determined New Source Performance Standard (NSPS) for that pollutant. If covered by non-attainment provisions, the source is required to install Lowest Achievable Emission Rate (LAER) and obtain applicable offsets for that particular area.[39] Like BACT, LAER must not be less stringent than the federal NSPS.

There is no firm data that NSR has obstructed the construction and operation of new power plants. The controversy over NSR with respect to power generation focuses on existing facilities and under what conditions they meet the modification trigger that would require them to undergo NSR. As defined under the 1970 Clean Air Act, a modification is "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."[40]

Enforcing these thresholds has been more difficult than their apparent clarity would suggest. EPA's thresholds for the NSPS program generally represent no practical constraint on life extension efforts by utilities. Most life extension efforts improve the availability and reliability of generating units, not their capacity to generate. Thus, their maximum hourly emission rate would not change. Likewise, most life extension efforts cost far less than 50% of a plant's asset value, an NSPS threshold under EPA regulations.[41]

NSR review has a far more sensitive trigger – a tonnage increase in pollutant output. Because life extension does improve availability and reliability, it is likely

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[36] Some restrict the term "NSR" to the review process in a non-attainment area only; the review process in an attainment area being called "PSD pre-construction review." This report uses the term to indicate both. In addition, new and modified sources must meet New Source Performance Standards (NSPS).

[37] 40 CFR 52.24(f)(10) for nonattainment; 40 CFR 52.21(b)9230(i) for PSD.

[38] It should be noted that a source can be affected by the PSD requirements for one pollutant, and by the non-attainment requirements for another pollutant.

[39] For details on these provisions and their requirements, see *Clean Air Act, Part C – Prevention of Significant Deterioration of Air Quality, sections 160-169; and, Part D – Plan Requirements for Nonattainment Areas, sections 171-178*.

[40] Section 111(a)(4).

[41] 40 C.F.R. 60.15.

to increase emissions over levels emitted before the life extension activities were undertaken. But how does one measure the change? What are the baselines[42]?

Fundamental to the debate on NSR enforcement with respect to existing facilities is the notion of "routine maintenance." In promulgating implementing regulations, EPA exempted certain activities from the definition of physical or operational change. Among those activities exempted was: "maintenance, repair, and replacement which the Administrator determines to be routine for a source category...."[43] Responding to this situation, utilities began to spread out their life extension efforts in an attempt to make them fit into their routine maintenance schedules.[44] Much of the debate, therefore, focuses on whether "routine maintenance" has become a major NSR loophole for power plant owners.[45]

A change in NSR is unlikely to have a significant impact on overall coal production, particularly with respect to construction of new generation.[46] With respect to existing facilities, if more stringent SO_2 controls were to result from rigorous enforcement of NSR, an advantage for low-sulfur coal could be reduced if those more stringent controls involved technology (such as scrubbers) rather than switching to lower-sulfur coal.

Global Climate Change. Except for requiring utility monitoring of emissions, CO_2 is not controlled under the CAA, and controversy exists as to whether CO_2 should be considered a pollutant at all. The slim chance that the regulatory regime adopted at Kyoto would be ratified by the Senate contributed to the Clinton

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[42] Defining the baseline has been a key issue. Every powerplant has what is called "nameplate" capacity, which indicates its theoretical size; but the actual output is defined by its "operating capacity," which is determined by the engineering and operational details of the individual plant. Moreover, from an engineering perspective, the operating capacity declines over time as a result of boiler deterioration, pipe clogging, and other predictable changes due to use. The issue is, then, what level of capacity restored by renovations triggers NSR?

[43] 40 CFR 60.14(e)(1)

[44] As observed by Robert Smock, Editor, "Power Plant Life Extension Trend Takes New Directions," *Power Engineering* (February 1989): "There are signs that many utilities will not use the term "life extension" to describe their spending on old power plants, even though extended life is one of the major goals of the spending program. The reason for the aversion to the term lies in the 1970 Clean Air Act. That federal law requires all power plants constructed after August, 1971 to restrict emissions of air pollutants such as sulfur dioxide. Plants built prior to 1971 are exempt, which includes most of the early candidates for life extensions. The problem is that the law also says that grandfathered plants can lose their exemption if they are "modified" or "reconstructed" in a major way and emission of proscribed pollutants are increased."(p.21)

[45] See Larry Parker and John Blodgett, *Clean Air: New Source Review Policies and Proposals*, CRS Report RL31757.

[46] See Larry Parker, *Clean Air: New Source Review Policies and Proposals*, CRS Report RL31757.

Administration's refusal to even submit the treaty to that body. At the same time, the country is obligated under the 1992 United Nations Framework Convention on Climate Change (FCCC) to pursue strategies with the goal of maintaining CO_2 emissions at their 1990 levels.[47] Current CO_2 emissions are about 10% above their 1990 levels. The Bush Administration has abandoned both the Kyoto Protocol process and the FCCC goal of maintaining CO_2 emissions at their 1990 levels. Instead, it has proposed a voluntary program to reduce the ratio of greenhouse gas emissions to Gross Domestic Product (GDP) over the next 10 years. However, absolute emission levels would continue to increase over this time period.

In the face of scientific uncertainty, the focus of U.S. debate on a climate change policy can be categorized by the three-Cs: (1) cost (the impact on the economy); (2) competitiveness (impact of U.S. global competitiveness); and (3) comprehensiveness (desire for a level playing field for all countries). A CRS survey of 17 cost estimates for the Kyoto Protocol resulted in a range of between $23 and $348 a metric ton of CO_2 removed.[48] Such an order of magnitude difference in cost estimates makes consensus difficult. This situation is particularly true for the coal industry, which would feel a substantial burden under any reduction scheme.

Several factors can both lower the cost and reduce the range of cost estimates presented above. One major factor in producing the $23 - $348 range was assumptions made about the viability of emissions trading under Kyoto. CO_2 reduction cost estimates for global emissions trading scenarios are in the range of $23-$50 a ton. However, serious questions have been raised as to whether the trading mechanisms embodied in the Kyoto Protocol could produce the cost savings suggested by some studies.[49] Some of the these objections might be swept away under a properly designed four-pollutant strategy, because such a strategy would not necessarily be designed to meet the Kyoto targets. Several of the four-pollutant strategies proposed in the 107th Congress chose the FCCC 1990 stabilization target for their CO_2 cap, not the Kyoto reduction requirement.

Setting a CO_2 reduction target under a four pollutant strategy would be a very contentious issue. CO_2 emissions from electric generation have risen about 23% from 1990 to 2000. Add to this an additional 19% for increased emissions anticipated between 2000 and 2010, and a reduction requirement back to the FCCC target would be a substantial undertaking. However, the cost would be less than if the additional 7% required by Kyoto were added to the reduction requirement.

Several of the building blocks for a CO_2 cap and trade program are in place. There is an established baseline (1990), and a credible inventory for powerplant emissions. Continuous CO_2 emissions monitoring is required for power plants under the 1990 CAAA. There is some experience with international emission credits

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[47] See John Blodgett and Larry Parker, *Global Climate Change: Reducing Greenhouse Gases – How Much from What Baseline?* CRS Report 98-235 ENR.

[48] Larry Parker, *Global Climate Change: Lowering Cost Estimates through Emissions Trading – Some Dynamics and Pitfalls*, CRS Report RL30285.

[49] *ibid*.

thanks to the Joint Implementation program pioneered by the United States in the mid-1990s. The issues of baselines for international projects and domestic allocations would be contentious; however, the advantage of CO_2 not having been controlled is that policymakers can begin with a relatively clean sheet.[50]

As noted under "multi-pollutant" legislation, CO_2 control could have a substantial effect on coal production, depending on its specifics. The more modest the CO_2 reduction, the longer the compliance deadline, and the more flexible the compliance strategy, the less the impact. As noted, a stringent program such as compliance with the Kyoto Protocol would have a substantial effect.

(For more information about legislative proposals on air emissions, see Larry Parker, *Air Quality: Multi-Pollutant Legislation in the 108th Congress*, CRS Report RL31779.)

Mountaintop Removal Mining[51]

The environmental, economic, and societal impacts of the surface mining practice termed "mountaintop removal mining" have attracted considerable attention. This type of surface mining occurs in Appalachian states ranging from Ohio to Virginia, especially in West Virginia.[52]

As its name suggests, mountaintop removal mining involves removing the top of a mountain with explosives and earth-moving machinery to uncover the coal seams contained in the mountain. Mountaintop removal creates an immense quantity of excess overburden, or spoil, which is typically placed in valley fills on the sides of the former mountains. One consequence is that streams flowing through the valleys are buried.

While mountaintop removal mining has been practiced in some form since the 1960s, it became a prevalent coal mining technique in parts of central Appalachia during the 1990s for several reasons. First, as the demand for electricity increased, so has the demand for the relatively clean-burning, low-sulfur coal found in certain parts of Appalachia, particularly eastern Kentucky and southern West Virginia. Second, coal supplies near the surface have been significantly depleted. Third is the development of large draglines that are capable of moving over 100 cubic yards of earth in a single scoop.

Until recent years, excess spoil from coal mining was generally placed in the extreme headwaters of streams, affecting primarily ephemeral streams that flow

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[50] For a discussion of alternative market mechanisms for CO_2 control, see: Larry Parker, *Global Climate Change: Market-Based Strategies to Reduce Greenhouse Gases*, CRS Issue Brief IB97057, updated regularly.

[51] Prepared by Claudia Copeland, Specialist in Resources and Environmental Policy, Resources, Science, and Industry Division.

[52] For more information on this issue, see Claudia Copeland, *Mountaintop Mining: Background on Current Controversies*, CRS Report RS21421, February 11, 2003.

intermittently only in direct response to precipitation in the immediate watershed. Because smaller upstream sites are exhausted and because of the increase in mountaintop mining activity, today the volume of a single stream fill can be as much as 250 million cubic yards, with stream burials up to two miles long.[53]

Regulatory Setting. Regulation of valley fills from mountaintop removal mining occurs primarily under two federal statutory programs, the Surface Mining Control and Reclamation Act (SMCRA) and the Clean Water Act (CWA), and involves several federal and state agencies.

SMCRA addresses the necessary approvals for surface mining operations, as well as inspection and enforcement of mine sites until reclamation responsibilities are completed and all performance bonds are released.

The CWA prohibits the discharge of any pollutant from any point source into the waters of the United States, except in compliance with a permit issued under one of the two permit programs established by the statute. The two permit programs are the National Pollutant Discharge Elimination System (NPDES) program, administered by the Environmental Protection Agency (EPA) under CWA Section 402, and the dredge and fill permit program administered by the U.S. Army Corps of Engineers (Corps) under CWA Section 404.[54]

The NPDES program focuses primarily, but not exclusively, on discharges such as wastewater from industrial operations and sewage treatment plants. The standard for issuing a 402 permit – which sets limitations on the quantities, rates, and concentrations of water pollutants – is compliance with pollutant limitation and control provisions in the Act.

The Section 404 permit program applies to the discharge of dredged or fill material. Environmental guidelines for such discharges are promulgated by EPA in conjunction with the Corps. The standard for issuance of a 404 permit is consideration of the full public interest by balancing the favorable impacts against the detrimental impacts of a proposed activity.

Section 404 permits consist of two basic types: individual permits for a particular site, and nationwide (general) permits for categories of discharges that have no more than minimal adverse impacts on the waters of the United States. Disposal of excess overburden associated with mountaintop removal mining has generally been permitted by the Corps under Nationwide Permit 21, which authorizes discharges from surface coal mining activities that result in no more than minimal impact (site-specifically and cumulatively) on the aquatic environment.

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[53] "Brief for the Federal Appellants on Appeal from the U.S. District Court for the Southern District of West Virginia, in the U.S. Court of Appeals for the Fourth Circuit." *Bragg v. Robertson*, No. 99-2683. p. 6.

[54] The CWA authorizes delegation of both of these permit programs to qualified states. The NPDES program has been delegated to 44 states, including each of the Appalachian states where mountaintop mining occurs. The Section 404 program has been delegated to two states, neither in central Appalachia (Michigan and New Jersey).

The U.S. Fish and Wildlife Service (FWS), which implements and enforces the Endangered Species Act, also has responsibilities relevant to mountaintop removal mining. Coordination with FWS is required for both SMCRA and CWA permits.

Criticism and Legal Challenges to Mountaintop Mining. Critics of mountaintop mining say that, as a result of valley fills, streams and the aquatic and wildlife habitat that they support are destroyed by tons of rocks and dirt. In addition, critics assert that mountaintop removal cracks the walls and foundations of nearby homes; causes dust, noise and vibration from blasting; collapses drinking water wells; destroys nearby streams for fishing, hiking, swimming or aesthetic pleasure; and has forced the relocation of whole communities.[55] Environmental groups argue that the federal agencies' practice of authorizing valley fills under Section 404 permits is unlawful because mining overburden is waste material that pollutes and destroys waterways, and impacts are more than minimal, which is the standard for coverage by a nationwide permit.

The mining industry and its supporters argue that mountaintop mining is essential to the conduct of surface coal mining in the Appalachian region. Waste disposal in valley fills is a necessary part of that activity because of the steep topography of the region, and they assert that mountaintop mining would not be economic or feasible if producers were restricted from using valleys for the disposal of overburden. Requiring Section 402 permits, rather than 404 permits, would effectively prohibit a broad range of mining activities that have been allowed by longstanding practice, they say.

Critics have recently been using litigation to challenge the practice of mountaintop removal mining. In 1998, a West Virginia environmental group filed a lawsuit in federal court against the West Virginia Department of Environmental Protection and the Corps, alleging multiple violations of the CWA and SMCRA. The lawsuit asserted in part that the Corps had been granting permits that allow disposal of waste in U.S. waters, contrary to the CWA, and permits under the nationwide permit program that have greater than "minimal" adverse effects.

In an October 1999 ruling, the federal district court held that disposal of mining spoil in valley streams violated federal and state mining rules and the CWA (*Bragg v. Robertson*, 72 F.Supp.2d 642 (S.D.W.Va. 1999)). Under the ruling, mining spoil was reclassified from its current description as "dredge and fill material" to "waste material" that is subject to CWA Section 402 permit requirements, thus raising the regulatory hurdles for disposal.

Upon appeal, the district court ruling was overturned on the basis of jurisdiction and state sovereignty issues (*Bragg v. Robertson*, 248 F.3d 275 (CA4 2001)). In January 2002, the Supreme Court declined to hear a challenge to the 4th Circuit decision.

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[55] Rosenberg, Daniel L. "Mountaintop Mining and Proposed Rule Change Will Waste Clean Water Act." *National Wetlands Newsletter*, vol. 22, no. 4, July-August 2000. p. 12.

A second lawsuit was brought in August 2001 challenging issuance of a permit under the Corps' Nationwide permit program for a mountaintop mining operation in Kentucky. The same federal district court judge who heard the *Bragg* case similarly ruled in this case that the disposal of waste from mountaintop mining into U.S. waters is not allowed under Section 404, and he permanently enjoined the Corps from issuing Section 404 permits for the disposal of mountaintop mining overburden where the purpose is solely to dispose of waste (*Kentuckians for the Commonwealth v. Corps of Engineers*, S.D.W.Va., No. 2:01:0770, 5/08/02). Upon appeal, the 4th U.S. Circuit Court of Appeals ruled that the district court's action was too broad, and the court lifted the injunction prohibiting the Corps from issuing Section 404 permits for disposal of mountaintop mining waste (*Kentuckians for the Commonwealth v. Rivenburgh*, No. 02-1736, and *Pocahontas Development Corp. et al v. Rivenburgh*, No. 02-1737, CA4, 1/29/03). No appeal has been filed at this writing.

Administrative Actions and Congressional Activity. Additional controversies over these issues arose because of a proposal by EPA and the Corps in April 2000 to revise regulations that implement CWA Section 404 by redefining the terms "fill material" and "discharge of fill material." One effect of the agencies' proposal was to establish regulatory definitions more consistent with the Clinton Administration's position in the then-ongoing *Bragg* litigation, namely its view that regulating mountaintop removal mining under CWA Section 404 is not inconsistent with that Act. This proposed rule was not finalized before the Clinton Administration left office in January 2001 but was finalized by the Bush Administration, substantially as proposed, in May 2002.[56] Environmental groups continue to contend that the disposal practice is unlawful under the Clean Water Act and that the revised rules allow for inadequate regulation of disposal activities, including coal mining waste.

Some congressional interest in these issues has been evident. Industry groups and others had sought a legislative remedy for the U.S. district court's ruling in the *Bragg* case. Late in 1999, during debate on omnibus FY2000 appropriations legislation, Senator Byrd proposed legislative language that would have provided a two-year environmental waiver to allow mountaintop coal mining in West Virginia to continue. The provision passed as an amendment to a short-term continuing resolution (H.J.Res. 82), but it was not included in the final bill, the Consolidated Appropriations Act for FY2000 (P.L. 106-113).

Other Environmental Concerns

Subsidence. Mine subsidence occurs when the support of an underground mine roof shifts or collapses, causing the ground surface above to sink. It may take many years for the underground pillars in a conventional coal mine to give way to erosion or other factors. Greater use of longwall mining, in which no pillars are left underground, has increased public concern about subsidence.

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[56] Department of the Army, Corps of Engineers, and Environmental Protection Agency. "Final Revisions to the Clean Water Act Regulatory Definitions of 'Fill Material' and 'Discharge of Fill Material.'" 67 *Federal Register*, No. 90, May 9, 2002. pp. 31129-31143.

The altered ground slopes caused by subsidence can damage roads and buildings, and may interfere with natural drainage into rivers and aquifers. Subsidence is regulated under SMCRA, which requires underground mining to be conducted in a way that prevents subsidence from causing damage to the surface. Backfilling or leaving some coal in place can help prevent subsidence. Underground mining cannot take place in areas below impoundments, below aquifers used for water supplies, and near or below public buildings, unless it has been determined that subsidence will not cause damage to those sites.[57]

Acid Mine Drainage. Acid mine drainage occurs when water flowing from a mine becomes highly acidic because of exposure to iron sulfide, which is common in coal mines. Air and water in a mine react with the iron sulfide to produce sulfuric acid and iron hydroxide. EPA has cited acid mine drainage primarily from abandoned coal mines as the number-one water quality problem in Appalachia.[58] About 10% originates from surface mines and the balance from abandoned underground mines.

Two major methods are used to treat acid mine drainage. An "active" treatment uses hydrated lime or crushed limestone to neutralize the acidic water. A biological or "passive" treatment system uses anoxic (without oxygen) drains, limestone rock channels, alkaline recharges of the groundwater, and a diversion of the drainage through wetlands. The passive systems are inexpensive but unproven over the long run. OSM's Appalachian Clean Streams Initiative, which began in 1994, is designed to clean up acid mine drainage using public and private-sector support.

The Abandoned Mine Land (AML) Fund.[59] The AML Fund was established to address the reclamation of coal mines that were in operation prior to the enactment of SMCRA, and whose owners are no longer in business or cannot be held liable for reclamation because there were no standards then in place. The AML fund and program is administered by the Office of Surface Mining (OSM). The fund is financed by fees collected on coal production. The collections are split into federal and state shares and distributed to states with approved reclamation programs. Annual distributions are set by congressional appropriation.

Because receipts to the fund have exceeded appropriations, the fund has an unobligated balance currently exceeding $1.6 billion. Some of the interest generated by those balances is paid to the United Mine Worker Combined Benefit Fund. Still, many states would like to see the pace of distributions accelerated, or would like to see the formula for grant distribution changed. Coal production has moved westward, and these states are now paying more into the AML fund while the greater percentage of abandoned coal mine sites remains in the East and Appalachia. The

[57] U.S. Congress, Office of Technology Assessment, The Direct Use of Coal, Prospects and Problems, of Production and Combustion, 1978.

[58] Office of Surface Mining, Department of the Interior Circular, "A Plan To Clean Up Streams Polluted By Acid Drainage." This circular can be found at www.osmre.gov/acsiplan.

[59] Prepared by Robert Bamberger, Specialist in Energy Policy, CRS Resources, Science, and Industry Division.

AML fund's authorization expires at the end of FY2004; reauthorization is likely to be controversial.

Health and Safety Issues[60]

Safety. Safety in the coal industry has undergone a steady trend of improvement since 1925. Whereas in that year there were 2,518 fatalities in accidents, the number has fallen almost continually since, reaching an all-time low of 27 in 2002. Some of this trend is explained by a decrease in coal industry employment (from 749,000 in 1925 to about 115,000 currently, according to MSHA statistics[61]), some of it by a shift from underground to surface mining, but most of it by safety improvement. Thus, the overall annual fatality rate decreased over the period from 3.36 per thousand workers to 0.23 per thousand. Nevertheless, coal mining remains one of the most dangerous industries in which to work, its fatality rate still at least five times the average for all private industry, and exceeding that of many industries generally thought to be dangerous, such as construction and trucking.[62]

The Mine Safety and Health Administration (MSHA) is charged with overseeing the safety of coal and other mining industries. MSHA's budget of $253 million (FY2002) is somewhat less than the $443 million of its sister agency, the Occupational Safety and Health Administration (OSHA), but OSHA is responsible for protecting a far larger number of workers. MSHA oversees a mining industry (including surface operations and all other minerals besides coal) of about 200,000 workers, while OSHA is responsible for most of the rest of the economy. Thus, MSHA is able – and indeed, mandated – to perform site inspections much more frequently than does OSHA.

Accident Prevention. Although mine accidents have declined greatly in frequency and severity over the years, all parties involved agree that there is still room for improvement. The United Mine Workers union has been particularly vocal in criticism of MSHA. It contends that there is an insufficient number of inspectors and that penalties, both as proposed and as negotiated, are not strong enough. In general, the union would make enforcement of standards the highest priority.[63] The mining industry generally supports MSHA's existing regulatory approach, although it has urged that inspections be focused on mines with indications of problems rather than be distributed among all mines as currently required.

MSHA, in its latest five-year plan, chooses a strategy of "expanding existing outreach efforts in the mining community, and shifting the emphasis of regulatory

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[60] Prepared by Edward Rappaport, Analyst in Industry Economics, CRS Domestic Social Policy Division.

[61] MSHA industry employment numbers differ from EIA figures because of the number of mines included and other factors.

[62] Bureau of Labor Statistics, *National Census of Fatal Occupational Injuries, 2001*.

[63] UMWA Calls on MSHA to End Coal Mine Fatalities. *United Mine Workers Journal*, March 2002. p. 18.

programs from after-the-fact enforcement to education and training and accident prevention." Through these initiatives – as well as continued enforcement – the agency aims to substantially reduce fatal and non-fatal injury rates by as much as half by 2005. It will also continue working on long-term health hazards by reducing the prevalence of excessive exposures to dust and noise.[64]

Some recent, widely publicized accidents have highlighted specific areas that may merit further attention. The accidental flooding of the Quecreek Mine in Pennsylvania in July 2002 raised questions about the accuracy of underground mine maps and their availability to operators of nearby mines. The Quecreek accident might have been avoided if the mine operator had had access to the final map of a nearby abandoned mine that had since filled with water. The Pennsylvania State government is acting to redress the deficiencies that led to the accident. In response to the Jim Walter No. 5 mine accident in Alabama in September 2001 (which took 13 lives), MSHA is making a number of changes, including additional training for inspectors, increased management oversight, and a new standard on mine emergency response. Most of the victims in this case were responding to a relatively small explosion when a larger one occurred. The mine workers union alleges that MSHA had not followed up properly on numerous previous violations.[65]

Health Protection. Accidental injuries can be quantified much more reliably than the extent of occupationally caused disease. At this point, though, it seems safe to say that coal mining has caused disability more by way of long-latency disease than by traumatic injury. Prime among these diseases is black lung (coal workers' pneumoconiosis (CWP)), which still claims about 1,400 fatalities per year (down by about half since 1982). Improved dust control requirements led to a decrease in the prevalence of the disease from the 1970s into the 1980s, but rates have basically leveled out since then.[66]

MSHA is expressly required by its authorizing statute to enforce a dust control standard (currently set at 2 milligrams/cubic meter as an 8-hour average "for each miner in the active workings of each mine"). There has been continual controversy about how concentrations are to be measured and how MSHA is to monitor the operators' plans and performance. In July 2000 MSHA proposed new regulations under which its inspectors would verify plans and performance by directly collecting single full-shift samples, rather than the previous practice of multiple samples retrieved by the operators. On March 6, 2003, a revised verification regulation was proposed, and the rulemaking reopened on the companion proposal regarding measurement methods.[67]

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[64] Strategic plan available at [www.msha.gov/MSHAINFO/STRAPLAN/STRAPLAN.pdf].

[65] See union complaint at [www.umwa.org/brookwood/brookwood.shtml].

[66] For example, among miners with 10 to 14 years of work, the number with positive x-rays declined from 8.8% in the mid-1970s to 1.7% in the mid-1980s, but rose to 2.2% in the mid-1990s. U.S. Department of Health and Human Services. *Work-Related Lung Disease Surveillance Report*. Cincinnati: NIOSH, 1999 (DHHS report no. 2000-105). Table 2-11.

[67] 68 Federal Register 10783.

Meanwhile, MSHA has been working on or has recently issued regulations dealing with a number of other respiratory hazards that affect coal miners, including diesel particulates, asbestos, and silica.

Black Lung Benefits Program. The Black Lung Benefits fund is paying some $400 million per year in income and medical benefits to more than 60,000 primary beneficiaries. The basic support payment is $535 per month as of 2003, augmentable if there are dependents. Miners are eligible if they are disabled due to CWP or other chronic dust disease arising out of coal mine employment. In December 2000 the Department of Labor issued the first extensive revision of its black lung regulations since 1983. The revisions were generally regarded as making benefits easier to obtain in some cases. Controversy about eligibility has occurred in legislative, regulatory, and judicial forums since the inception of the program.

In the 107th Congress, the Bush Administration proposed a refinancing of the black lung trust fund, which owed more than $7 billion to the Treasury as of FY2002. Although program revenues (from a tax on coal production) have exceeded the cost of benefits in recent years, the debt to the Treasury has been growing because of accumulating interest charges. The Administration proposal would eventually retire the debt, primarily through intragovernmental transfers with arguably no budgetary impact, but also by requiring an extension of the coal tax that finances the fund beyond its currently scheduled expiration of 2014.

Coal Research and Development[68]

Technology areas for coal research and development include improved power generation, cleanup of emissions, and production of coal-derived fuels.

As noted previously, most U.S. coal is used to generate electricity. In the traditional approach to electricity generation, coal is burned to heat water, and the resulting steam drives a turbine-generator. Advanced techniques can result in lower fuel consumption and reduced emissions of pollutants and carbon dioxide. The most prominent approach is integrated gasification combined cycle (IGCC), in which coal is gasified to fuel a combustion turbine, whose exhaust is then used to heat water to drive a steam turbine.

Because of the large base of existing power plants, techniques for improving the performance and emissions of existing power plants are also a major area of research. A growing research emphasis is the capture and sequestration of carbon dioxide emissions, such as through injection into underground coal seams or depleted oil reservoirs. Research on the use of coal to produce liquid and gaseous transportation fuels is now focused mostly on production of hydrogen.

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[68] Prepared by Daniel Morgan, Analyst in Science and Technology Policy, CRS Resources, Science, and Industry Division.

Coal research is conducted at DOE in the Fossil Energy R&D program. Most prominent is the Clean Coal Power Initiative (for which $130 million is requested for FY2004). This is a cooperative program, with industry cost-sharing, that seeks to enhance the reliability, efficiency, and environmental performance of coal-fired power generators.[69] Other activities include Central Systems (FY2004 requested budget: $86 million), Sequestration R&D ($62 million), Fuels ($5 million), and Advanced Research ($37.5 million).

The Clean Coal Power Initiative succeeds and continues the Clean Coal Technology program. The Clean Coal Technology program is made up of 38 demonstration projects, the last of which were selected in 1993. (Most have now completed their demonstration phase, although many of the completed demonstrations remain in commercial operation.) All federal funds for Clean Coal Technology were provided by Congress between FY1986 and FY1997 in the form of advance appropriations totaling $1.8 billion. The private sector has provided an additional $3.5 billion, with each project receiving at least half its support from private funds.

The DOE Vision 21 initiative seeks to integrate research and development in several areas, including coal as well as other fuels, with the ultimate goal being a high-efficiency, low-emissions power plant that combines generation of electricity with other products such as industrial heat, chemicals, or hydrogen.[70] The *Vision 21 Technology Roadmap*[71] provides an overview of the concept and the technologies involved and, for each technology area, identifies the current status and the initiative's approach to meeting its objectives over the next five, 10, and 15 years.

Outlook and Recap

The outlook for U.S. coal is mixed. While supply and demand forecasts indicate coal will still have a dominant but smaller position in the electricity market, mine closures and employment losses are expected to continue. There appears to be a trend toward increased production from fewer mines, larger mines, and fewer producers.

The continued strong market position of the relatively few major buyers, utilities in particular, will likely be one factor putting downward pressure on coal prices. Production costs for many coal operators are falling and will likely continue to fall as they employ new production technology. But future technology development may be constrained by low or nonexistent profit margins.

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[69] The web page of the Clean Coal Power Initiative is <http://www.fe.doe.gov/coal_power/cct/ccpi/>.

[70] The webpage of the Vision 21 initiative is <http://www.netl.doe.gov/coalpower/vision21/>.

[71] The Vision 21 roadmap is available online at <http://www.netl.doe.gov/coalpower/vision21/roadmap.html>.

As electricity demand increases, new coal-fired plants may become more economic than natural gas plants at gas prices near $4 per million Btu.[72] And EIA forecasts that natural gas prices will rise high enough after 2010 to keep coal competitive. However, EIA also predicts that coal's share of electricity production will drop from its current 52% to 47% in 2025. Some energy analysts argue that the future price of natural gas may be overstated and that the future market share of natural gas in the electricity market has been underestimated.[73]

The federal government, with its regulatory role and as the largest holder of coal reserves, will be a significant player in the future of U.S. coal. Major issues – discussed in the body of this report – range from environmental regulations to federally funded research on coal technology. These are summarized in **Table 8**.

Table 8. Recap of Major Coal-related Issues

Issue	**Comment**	**Legislative Activities/ Further Information**
Abandoned Mine Lands	Many states would like to see changes in the distribution of the AML fund. Coal production has moved westward, so Western states are paying more into the fund while most of the abandoned mine sites remain in the East.	The AML fund is up for reauthorization at the end of 2004.
Clean Air Act: Impact on coal markets of replacing or supplementing CAA command and control mechanisms for electric generating facilities with a market-oriented multi-pollutant approach to air pollution control	This is a major initiative of the Bush Administration, involving emission caps on NOx, SO_2, and Hg. Contentious issues include stringency of caps, compliance deadlines, regulatory relief from other provisions of CAA, and inclusion of CO_2 emissions.	Bills introduced in the 108th Congress. See CRS Report 31779 for comparison of proposals. See CRS Report RL 30878 for in-depth background on the issue.

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[72] Ewart, *op. cit*.

[73] Economics of the Minerals Industry, 4th Edition, The Economics of Coal and Nuclear Energy, Richard Newcomb and Michael Rieber, AIME, 1985.

Global Climate Change	Mandatory controls on carbon dioxide – a major coal emission – have been rejected by the Bush Administration as too costly and disruptive. However, both independent and multi-pollutant bills including CO_2 have been introduced, with one reported by the Senate Environment and Public Works Committee in the 107th Congress.	Bills have been introduced in the 108th Congress. See IB97057 for background on controlling greenhouse gases, including legislation. See CRS Report 31779 for a review of legislation in the context of multi-pollutant proposals and the Administration's voluntary initiative.
Mine Safety	MSHA wants to expand outreach efforts in mining communities from after-the-fact enforcement to education, training and accident prevention. The goal is to reduce the injury rate in half by 2005.	None
Mountaintop Mining	Mountaintop mining involves removing the top of a mountain to recover the coal seams within. Excess overburden is placed in valley fills on the sides of the former mountain. One consequence is that streams flowing through the valleys are buried.	A January 2003 decision in the U.S. Circuit Court of Appeals overturned an earlier U.S. District Court decision that ruled valley fills violated the Clean Water Act. Legislation has been introduced in the 108th Congress to overturn recent regulations on valley fill permits. For details, see *Mountaintop Mining: Background on Current Controversies*, CRS Report RS21421.

New Source Review: Impact on coal markets of modifying or eliminating current NSR provisions with respect to electric generating facilities	This is a major regulatory and legislative initiative of the Bush Administration. Some regulatory changes have been promulgated while others have been proposed. The Administration's proposed multi-pollutant legislation contains broad relief from NSR.	Regulations have been promulgated and proposed. Legislation has been introduced in the 108th Congress. See CRS Report 31757 for an in-depth discussion of the issue.
Research and Development	The Clean Coal Power Initiative is most prominent of the coal R&D programs. This initiative succeeds and continues the Clean Coal Technology Program.	$150 million was appropriated in FY2003 and $130 million is sought in FY2004.
Taxes	Coal is subject to special taxes for black lung benefits and abandoned mine land reclamation but also can qualify for synthetic fuel credits.	Legislation extending synthetic fuel tax credits for coalbed methane has been introduced in the 108th Congress.