Coal Assessment

New York State Energy Plan 2009

December 2009

1 Overview

This Assessment characterizes coal use, production, prices, transportation, and reserves at the global, national and State levels. Recent trends and developments in the coal industry are addressed, including advanced coal technologies and environmental factors that affect how coal is used. In addition, current New York and federal programs and initiatives that relate to the use of coal are identified.

Although New York has neither coal mining activity nor known coal reserves, coal is a relatively low-cost domestic fuel that is nationally and regionally plentiful. Coal offers fuel diversity to the State. In 2007, New York used 253 trillion British thermal units (TBtu) of coal, which represents 6.1 percent of the State's total primary energy use and 13 percent of its electricity generation. In contrast, coal accounts for nearly 50 percent of U.S. electricity generation.

Coal is a plentiful domestic resource and, at 27 percent of the world's known recoverable coal reserves, the United States has the largest national share, followed by Russia, China, and India (17, 13, and 10 percent, respectively). Based on its current rate of use, the United States has a 242-year supply of known recoverable reserves of coal.

Among global producers, U.S. coal production (20 percent) is second only to China's (30 percent). Nearly all of U.S. coal production is used domestically and the surplus is exported, mostly to Canada and Europe. At 1.1 billion short tons[1] and 15 percent of global demand, the United States in 2007 was the second largest user of coal. At 2.9 billion short tons, which is equal to 40 percent of global demand, China was by far the largest user of coal.

Despite its low cost and abundance, increasing concerns over greenhouse gases and other emissions from fossil fuels are altering the technological and regulatory environment for coal. Programs in New York and in the nation are underway to limit, reduce, and capture emissions from coal plants. This may result in the emergence of new generation technologies and the increased use of advanced emissions control technologies. In so doing, the costs and economics of coal use may change.

[1] A short ton is a unit of weight equal to 2,000 pounds or 907.18 kilograms. In the United States, a short ton is referred to as a ton. In other countries, the term short ton is used to differentiate from the long ton (typically 2,240 pounds) or the metric ton (2,204 pounds).

2 U.S. Coal Production and Use

2.1 U.S. Coal Production

As shown in Table 1, U.S. coal production in 2007 was 1,146.6 million short tons and was produced at 1,438 mines nationwide. Coal producing regions are divided into three categories: Appalachian, Interior, and Western.

In the Appalachian region, West Virginia is the largest coal producing state, followed by Kentucky (eastern) and Pennsylvania. The Appalachian region is the largest source of coal used in New York.

In 2007, a total of 621.0 million tons of coal was produced in the western region of the United States, dominated by Wyoming, which accounted for 73 percent of the western regional production and nearly 40 percent of the U.S. production. Wyoming produced 453.6 million tons of coal, roughly the sum of the next seven largest coal-producing states. Coal production has grown rapidly in the western region in recent years and is now 54 percent of U.S. production. Western coal, principally subbituminous, is surface mined.

Coal production in the Interior region of the United States was 146.6 million tons in 2007, where Texas was the largest coal producing state, followed by Indiana and Illinois.

Despite increased annual coal production in 2007 compared to 2006, overall production and distribution was affected by mine closures related to safety concerns, labor and equipment shortages, and transportation problems that affected the amount of coal moved to markets. With the majority of coal being shipped by rail, and the railroads transporting record levels of coal and other commodities, the resulting bottlenecks throughout the country led to several delays in delivering coal to utilities during 2007.

Table 2 highlights the different types of coal based on their carbon, sulfur and moisture contents, and heating value. Bituminous and subbituminous coals have heating values that respectively average 24 and 18 million British thermal units (MMBtu) per ton and these two types of coal collectively represent 93 percent of U.S. production. Subbituminous coals offer lower sulfur contents by weight compared to bituminous coal, making them more attractive for meeting air quality standards for electric generators. The western region produces the vast majority of subbituminous coal, while the Interior region produces primarily bituminous coal and some lignite. The Appalachian region is the principal source of bituminous coal and the sole source of anthracite in the United States.[2]

[2] Anthracite, ranked highest among the different types of coals in heating quality, has an average heating value of 25 MMBtu per short ton, carbon content between 86 and 97 percent, and sulfur content by weight of 0.6 percent. Despite its high heating value, anthracite makes up only 0.1 percent of U.S. coal use due to its limited availability.

Table 1. U.S. Coal Mined by Region and Selected States - 2007

U.S. Coal Mined by Region and Selected States - 2007		
Regions and Largest State Producers*	**Number of Mines**	**Production (Million Short Tons)**
Appalachian Region	**1,200**	**377.8**
Alabama	49	19.3
Kentucky (eastern)	417	87.1
Ohio	57	22.6
Pennsylvania	264	65.0
Virginia	118	25.3
West Virginia	282	153.5
Interior Region	**100**	**146.7**
Illinois	21	32.4
Indiana	27	35.0
Kentucky (western)	23	28.2
Texas	11	41.9
Western Region	**58**	**621.0**
Colorado	12	36.4
Montana	6	43.4
New Mexico	4	24.5
North Dakota	4	29.6
Utah	10	24.3
Wyoming	20	453.6
U.S. Total**	**1,358**	**1,146.6**

Source: U.S. Energy Information Administration (EIA). *Annual Coal Report 2007:* Table 1. 2009 http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf

*Only the 15 largest states by level of production are included. Smaller producing states that are not listed include Tennessee, Maryland, Kansas, Louisiana, Missouri, Mississippi, Oklahoma, Alabama, and Arizona.

*** U.S. production totals also include coal refuse recovery production that is not reflected in the regional totals.*

Table 2. Types of Coal and Their Characteristics

Types of Coal and Their Characteristics					
Coal Type	**Percent Carbon**	**Heating Range Values (MMBtu/ton)**	**Heating Avg. (MMBtu/ton)**	**Moisture Content by Weight**	**Sulfur Content by Weight**
Anthracite (hard coal)	86-97%	22 to 28	25	usually < 15%	0.6%
Bituminous (soft coal)	45-86%	21 to 30	24	usually < 20%	1.4%
Subbituminous (black lignite)	35-45%	17 to 24	18	20-30%	0.4%
Lignite (brown coal)	< 35%	9 to 17	13	as much as 45%	1.0%
Source: EIA. *Annual Coal Report 2004*. 2005.					

Table 3 lists U.S. coal production by type of coal and mining methods. Coal production in the United States has grown steadily from 612.6 million short tons in 1970 to 1,146.6 million short tons in 2007.[3] Much of this increase is due to the rapid growth of subbituminous coal production. In 1970, bituminous was 94.4 percent of U.S. coal production; however, by 2007, bituminous and subbituminous accounted for approximately 47.3 percent and 45.7 percent of total production, respectively. In 2007, more than 69 percent of U.S. coal was produced from surface mines and over 58 percent was produced west of the Mississippi. West of Mississippi coal production eclipsed east of Mississippi coal beginning in 1999.

Table 3. 2007 U.S. Production by Coal Type and Mining Method (Million Short Tons)

2007 U.S. Production by Coal Type and Mining Method (Million Short Tons)		
Production	**Million Short Tons**	**Percent**
Classification		
Bituminous Coal	542.8	47.3
Subbituminous Coal	523.7	45.7
Lignite	78.6	6.9
Anthracite	1.6	0.1
Mining Method		
Underground	351.8	30.6
Surface	794.8	69.4
Origin		
West of the Mississippi	668.5	58.3
East of the Mississippi	478.2	41.7
Source: EIA. *Annual Energy Review 2008*. http://www.eia.doe.gov/emeu/aer/pdf/pages/sec7.pdf		

Table 4 provides estimates for the demonstrated reserve base, estimated recoverable reserves, and recoverable coal reserves at producing mines. The demonstrated reserve base (DRB), or the estimated

[3] EIA. *Annual Energy Review 2006: Table 7-1, Table 7-2*. 2007.

quantity of in-ground coal resources, in the United States was 489.4 billion short tons in 2007. Although found in many states, approximately 58 percent of the U.S. DRB is concentrated in Illinois, Montana and Wyoming.

Table 4. Demonstrated Reserve Base, Estimated Recoverable Reserves, and Recoverable Coal Reserves at Producing Mines, 2007 (billion short tons)

Demonstrated Reserve Base, Estimated Recoverable Reserves, and Recoverable Coal Reserves at Producing Mines, 2007 (billion short tons)			
Mining Method	**Demonstrated Reserve Base**	**Estimated Recoverable Reserves**	**Recoverable Coal Reserves at Producing Mines**
Underground	333.3	149.5	5.8
Surface	156.1	113.2	12.8
U.S. Total	489.4	262.7	18.6
Source: EIA. *Annual Coal Report 2007.* 2009. http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf			

Although the DRB is nearly 500 times the annual U.S. coal production rate, not all of the DRB is recoverable at current prices and technologies. The U.S. Energy Information Administration (EIA) estimates that more than half (262.7 billion tons) could be economically recoverable with the application of current extraction technologies.[4] Based on its current rate of use, the United States has a 242-year recoverable supply of coal. The amount of recoverable reserves at active mines in the United States is estimated at 18.6 billion tons.[5] Approximately two-thirds of active recoverable reserves are found in surface mines (12.8 billion tons), and these are primarily found in the western region.

Over the past several decades, increasing scale of operations and the need for capital has helped drive significant changes in the U.S. coal mining industry, including consolidation, improved output and productivity, greater use of technology, and a reduction in the mining workforce. As shown in Table 5, consolidation in mine production has been significant with the number of operating mines declining from 2,104 in 1995 to 1,358 in 2007. The 10 largest coal mines, all surface mines located in Wyoming, account for more than one-third of U.S. production, and the 10 largest coal producing companies, account for two-thirds of U.S. production. In addition, labor productivity has significantly improved. Labor composes roughly half of total mining costs, making it a major cost component for coal producers. Coal mine productivity improved from 5.4 to 6.3 short tons per employee per hour from 1995 to 2007, primarily due to a 25 percent rise in output from surface mines from 1995 to 2006, while the average number of daily employees declined from 90,000 to 81,000. The U.S. coal mining industry also has adopted a number of technological changes to improve the productivity and cost-effectiveness of mining operations, such as improved mining equipment, better material handling techniques, and enhanced automation of equipment monitoring and operation.

[4] EIA. *Annual Coal Report 2007.* 2009. http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf

[5] Based on information from mine operators for each active property.

Table 5. U.S. Coal Mining Statistics

U.S. Coal Mining Statistics				
		1995	**2000**	**2007**
Production (million tons)	Underground	396	374	351
	Surface	637	700	794
	Total	1,033	1,074	1,146
Number of mines (active)	Underground	977	707	563
	Surface	1,127	746	795
	Total	2,104	1,453	1,358
Number of employees (thousands)	Underground	58	42	47
	Surface	32	29	34
	Total	90	71	81
Productivity (short tons per employee hour)	Underground	3.4	4.2	3.3
	Surface	8.5	11.0	10.2
	Average	5.4	7.0	6.3

Sources: EIA. *Annual Energy Review 2007*. 2008. http://tonto.eia.doe.gov/FTPROOT/multifuel/038407.pdf

EIA. *Annual Coal Report 2007*. 2009. http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf

EIA. *Annual Coal Report 2000*. http://tonto.eia.doe.gov/FTPROOT/coal/05842000.pdf

EIA. *Annual Coal Report 1995*. http://tonto.eia.doe.gov/FTPROOT/coal/058495.pdf

Note: Differences in totals are due to rounding.

2.2 U.S. Coal Use

In 2007, coal use in the United States reached an all-time peak of 1,128.8 million short tons.[6] In 2007, coal was used to produce 49 percent of all electricity generated in the United States.[7] The East North Central region (Illinois, Indiana, Michigan, Ohio, and Wisconsin) accounts for the largest portion of national coal use for the generation of electricity (23 percent) followed by the South Atlantic region (Florida, Georgia, North and South Carolina, Virginia, and West Virginia) (18 percent). On a statewide basis, Texas, Indiana, Illinois, Ohio, and Pennsylvania, respectively, were the top five coal customers.[8]

U.S. coal prices rose in 2007, continuing an upward trend since 2003. Steadily increasing domestic and international demand for coal, and increasing prices for other fuels, particularly petroleum and natural gas, contributed to rising coal prices. In recent years, global demand for coal has grown rapidly, particularly in Asia. From 2000 to 2007, annual global coal use grew 41 percent, from 5.1 to 7.1 billion

[6] EIA. *Annual Energy Review 2008: Section 7*. http://www.eia.doe.gov/emeu/aer/pdf/pages/sec7.pdf

[7] Reported coal use in the electric power sector does not include coal used for combined heat and power (CHP). Use of coal for CHP is contained in industrial and commercial sector figures reported by EIA; thus, actual contribution of coal to electricity generation is slightly higher than conventionally reported.

[8] EIA. *Annual Coal Report 2007: Table 26*. 2009. http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf

short tons.[9] Almost all of this growth (99 percent) was the result of increased coal use in the rapidly growing economies of Asia, primarily China.

As shown in Table 6 below, the average delivered cost of coal to electric utilities in 2007 was $36.06 per short ton, which is equal to $1.64 per MMBtu.[10] For the purposes of producing steam in the generation of electricity, coal is by far the least expensive fossil fuel on a dollar per MMBtu basis; See Petroleum and Natural Gas Assessments for price data. Metallurgical coal used in coke plants was nearly three times as expensive as steam coal used to produce electricity in 2007, since coke plants often rely on short-term contracts and the spot market.[11] For this reason, 92.7 percent of all coal in the United States was used in the electric power sector and has traditionally been used to fuel baseload generation, i.e., those generating units that run continuously rather than following periods of intermittent peak demand.

Table 6. 2007 U.S. Coal Use and Prices (million short tons and nominal dollars)

2007 U.S. Coal Use and Prices		
Use by Sector	**million short tons**	**percent**
Electric Power	1,045.1	92.7
Coke Plants	22.7	2.0
Other Industrial Plants	56.6	5.0
Residential/Commercial Users	3.5	0.3
Total	1,128.8	100
Average Delivered Price	**$/short ton**	
Electric Utilities	$36.06	
Independent Power Producers	$33.11	
Coke Plants	$94.97	
Other Industrial Plants	$54.42	
Source: EIA. *Annual Coal Report 2007*. 2009. http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf		
Note: Differences in totals are due to rounding.		

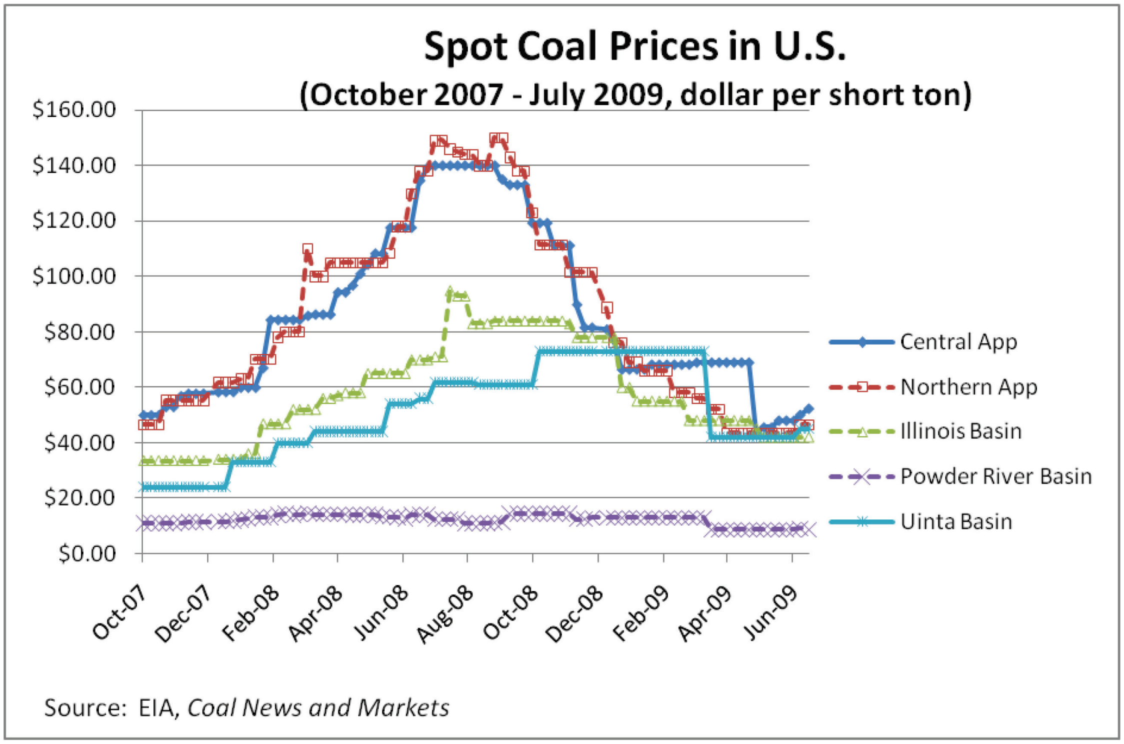
As shown in Figure 1, spot prices for various grades of coal spiked dramatically in the Spring and Summer of 2008, particularly for Northern and Central Appalachian coals, which are primarily bituminous. However, since September 2008, prices have declined precipitously. Uinta and Illinois Basin coals have steadily increased in price while Powder River Basin (Wyoming) coal has remained relatively steady.

[9] EIA. *Annual Energy Review 2008.* 2009. http://tonto.eia.doe.gov/FTPROOT/multifuel/038408.pdf

[10] This calculation assumes an average of 22 MMBtu per ton of coal. 2007 is the latest year that annual price data are available.

[11] Spot market prices provided by EIA represent prices for coal that can be delivered in the upcoming, or prompt, quarter.

Figure 1. Spot Coal Prices in the U.S. (October 2007 to January 2009, dollar per short ton)



2.3 U.S. Coal Transportation

Approximately two-thirds of all coal mined in the United States is transported by rail. Hauling coal is the largest single source of freight revenue for U.S. railroads. In 2003, the most recent year for which data is available, railroads received 20 percent of their revenues from transporting coal, and coal comprised over 40 percent of the total tons of freight hauled by rail. Over the past 10 years, the rail industry's share of coal transportation has increased, primarily to satisfy increased demand by electric generators for low-sulfur western coal from Montana and Wyoming. Domestic railroads carried 65 percent of the nation's coal, transporting a weekly average of 15 million tons of coal in 2003. Coal is also moved by barges, ships, and trucks, when these modes of transportation are more economical. A few electricity-generating facilities are located near coal mines and receive their coal directly by conveyor or coal-slurry pipeline.[12]

There is a large variation in transportation costs among the coal producing regions due to differences in shipping distance and transportation mode. Appalachian and Interior region coal is costlier at the minemouth,[13] but transportation costs are lower, involving relatively shorter hauls to consumers by rail and barge. Low-cost, low-sulfur western region coal is shipped primarily by rail over great distances, thus incurring higher transportation costs than Appalachian and Interior region coal.

Average coal rail hauls are getting longer, again reflecting the increased penetration of low-sulfur western coal carried by rail into the southern and eastern U.S. markets. Higher capacity cars and more powerful locomotives have dramatically increased railroads' coal-carrying efficiency. Railroads continually adopt

[12] Coal-slurry is crushed coal mixed with water.

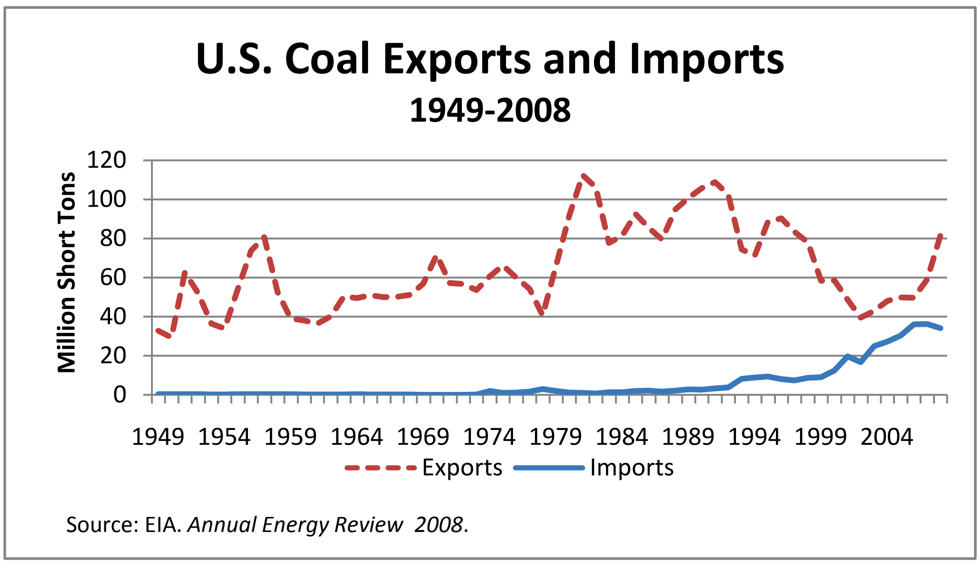
[13] Minemouth is the commodity cost of coal, or "freight on board" (FOB), excluding transportation costs.

technological innovations that offer customers greater flexibility, such as the “coaltainer,” a container designed especially for transporting coal by rail and by truck, and the use of real-time satellite monitoring and computerized traffic management systems to improve the scheduling and routing of trains.

2.4 U.S. Coal Imports and Exports

As shown in Figure 2, overall the United States is a net exporter of coal; it produces more coal than it uses, and it exports the surplus. In 2007 and 2008, net exports increased sharply due to heightened Asian demand. The United States also imports small amounts of coal when specific coal characteristics, i.e., low-sulfur, are desired and transportation rates are favorable. Imports have risen over the past twenty years, as highlighted by Figure 2. A key import driver is steam production at electric power plants; some international coal sources, such as Indonesia, offer low-sulfur, which helps generators meet air permit requirements.

Figure 2. U.S. Coal Exports and Imports, 1949-2008



3 New York State Coal Production and Use

In 2007, New York used 253 TBtu of coal, which represents 6.1 percent of the State's total primary energy use of 4,129 TBtu.[14] In that same year, coal-fired generation produced 13 percent of all electric output in the State. In 2007, the average cost of coal delivered to New York electricity generators was $58.98 per short ton, more than 63 percent higher than the national average of $36.06 per short ton.[15] This is due in large part to the long haul of low-sulfur western coal to New York and the higher relative cost of coal from the Appalachian region. New York has neither coal mining activity nor known coal reserves.

3.1 New York Coal Use

In 2007, New York used 10.8 million short tons of coal, an increase of one percent from 2006 and constituting less than one percent of the nation's total coal demand.[16] Electricity generation was 89.3 percent of this total, while the industrial sector accounted for 9.5 percent, and the residential and commercial sectors used 1.2 percent. Over the past several years, the amount of coal used for electricity generation has remained stable, while coal used by the residential, commercial, and industrial end-use sectors has declined. In 2007, New York ranked thirty-third among U.S. states in coal use.[17]

3.2 Coal Prices for New York Generators

As shown in Table 7, the delivered cost of coal to electric generating plants in New York has risen steadily over the past several years. Between 2000 and 2007, the average delivered nominal prices rose from $39.11 to $58.98 per short ton, representing a 50 percent increase.

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[14] New York State Energy Research and Development Authority (NYSERDA). *Patterns and Trends - New York State Energy Profiles 1993-2007*. 2009. http://www.nyserda.org/energy_information/patterns%20&%20trends%201993-2007.pdf

[15] EIA. *Annual Coal Report 2007*. 2009. http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf

[16] EIA. *Annual Coal Report 2007: Table 26*. 2009. http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf

[17] EIA. *Cost and Quality of Fuels for Electric Plants 2006-2007*. 2008. http://www.eia.doe.gov/cneaf/electricity/cq/cqa2007.pdf

Table 7. Average Delivered Cost of Coal to New York Electric Generation Plants

Average Delivered Cost of Coal to New York Electric Generation Plants (dollars per short ton)		
Year	**Nominal Dollars**	**Real Dollars (2007)**
2000	$39.11	$47.09
2001	$37.06	$43.39
2002	$40.10	$46.22
2003	$38.81	$43.54
2004	$41.19	$45.21
2005	$54.94	$58.33
2006	$58.48	$60.15
2007	$58.98	$58.98

Source:
EIA. *Coal Industry Annual 2000*. http://tonto.eia.doe.gov/FTPROOT/coal/05842000.pdf
EIA. *Annual Coal Report 2001*. http://tonto.eia.doe.gov/FTPROOT/coal/05842001.pdf
EIA. *Annual Coal Report 2002*. http://tonto.eia.doe.gov/FTPROOT/coal/05842002.pdf
EIA. *Annual Coal Report 2003*. http://tonto.eia.doe.gov/FTPROOT/coal/05842003.pdf
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EIA. *Annual Coal Report 2006*. http://tonto.eia.doe.gov/FTPROOT/coal/05842006.pdf
EIA. *Annual Coal Report 2007*. http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf

New York electric generators primarily purchase coal under long-term contracts, but also purchase limited amounts in the spot market. In 2007, 93 percent of coal receipts were purchased under contract at an average price of $2.22 per MMBtu, or $57.70 per short ton. Spot market purchases of coal made up seven percent of receipts, at an average price of $2.27 per MMBtu or $59.03 per short ton.[18]

3.3 Coal Supply for New York

As shown in Table 8, nearly 98 percent of domestic coal delivered to New York in 2007 originated in three states: Pennsylvania (65 percent); West Virginia (11 percent); and Wyoming (22 percent). Coal from Wyoming has grown significantly in recent years due in large part to efforts to reduce sulfur dioxide emissions in conformance with the Clean Air Act. In the prior year of 2006, low-sulfur Wyoming coal grew as high as 43 percent of New York's coal supply, up from 4.1 percent in 2003.[19]

[18] EIA. *Cost and Quality of Fuels for Electric Plants 2006 and 2007*. 2008. http://www.eia.doe.gov/cneaf/electricity/cq/cqa2007.pdf

[19] EIA. *Domestic Distribution of U.S. Coal by Destination State, Consumer, Origin and Method of Transportation for 2006.* 2007.

The dominant mode (96 percent) of coal transportation into New York is rail,[20] followed by barge and trucks. Table 8 lists the origin of domestic coal delivered to New York in 2007 by method of transportation.

Table 8. Origin and Method of Transportation of Domestic Coal Delivered to New York

Origin of Domestic Coal Delivered to New York and Method of Transportation, 2007 (thousand tons)					
State	**Railroad**	**River**	**Great Lakes**	**Truck**	**Total**
Kentucky	55	39	0	2	96
Ohio	97	0	0	2	99
Pennsylvania	5,984	14	0	354	6,352
West Virginia	1,107	0	0	0	1,107
Wyoming	2,146	0	0	0	2,146
Total	**9,388**	**53**	**0**	**359**	**9,801**
Source: EIA. *Domestic Distribution of U.S. Coal by Destination State, Consumer, Origin and Method of Transportation 2007.* 2008. http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/2007/d_07state.pdf					
Note: Differences in totals are due to rounding.					

3.4 Coal Fired Generating Units in New York

New York currently has 10 coal-fired electricity generating plants, with 19 generating units, located in nine counties. These facilities, listed in Table 9, represent 2,711 megawatts (MW) of net summer capability for the New York electricity system. The majority of the coal generating plants were initially constructed in the 1950s, with some units coming online in subsequent years. Various environmental control technologies have been added on to these plants over the past two decades to meet increasingly stringent environmental regulations. The last constructed major coal plant was the Somerset plant in Niagara County, completed in 1984. Except for the Danskammer plant located in Orange County, New York's coal plants are all located well outside of the metropolitan New York City area, with the greatest concentration in western New York.

[20] EIA. *Domestic Distribution of U.S. Coal by Destination State, Consumer, Origin and Method of Transportation 2007.* 2008. http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/2007/d_07state.pdf

Table 9. Coal-Fired Generating Units in New York, Capacity, In-Service Dates, and Environmental Control Technologies

Coal-Fired Generating Units in New York, Capacity, In-Service Dates, and Environmental Control Technologies					
Company and Plant Name	**Units**	**County**	**In-Service Date(s)**	**2009 Summer Capacity (MW)**	**Environmental Control Technology**
AES Corp. - Cayuga	2	Tompkins	9/55, 10/58	306.1	ESP, FGD, SCR
AES Corp. - Greenidge	2	Yates	4/50, 12/53	155.5	MC, ESP, CI, BH, SCR, SNCR, SDI
AES Corp. - Somerset	1	Niagara	8/84	682.8	ESP, FGD, LNB, SCR
AES Corp. - Westover	2	Broome	1/44, 12/51	121.1	ESP, OFA
Dynegy Power - Danskammer	2	Orange	10/59, 9/67	367.2	ESP
Jamestown, City of	2	Chautauqua	8/51, 8/68	42.7	ESP, LNB
NRG Power - Dunkirk	4	Chautauqua	11/50, 12/50, 9/59, 8/60	534.8	ESP, BH, SNCR, DLI*
NRG Power - Huntley	2	Erie	12/42, 12/48	375.2	ESP, BH, SNCR, DLI*
Coral Power - Fort Drum	1	Jefferson	7/89	55.6	BH, DLI
Trigen Corp. - Syracuse	1	Onondaga	8/91	69.9	BH, DLI
Total	**19**			**2,710.9**	

Environmental Control Technologies include: ESP – electro-static precipitator; SCR - selective catalytic reduction; SNCR - selective non-catalytic reduction; DLI - dry lime injection; MC – multiclone; SDI - spray dry injector; FGD - flue gas desulfurization; CI - carbon injection; BH – baghouse; LNB - low NO_x burners; OFA - overfire air. These technologies are mentioned later in the Environmental Factors section.

Source: New York Independent System Operator (NYISO). *2009 Load and Capacity Report*. 2009. http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2009_LoadCapacityData_PUBLIC_Final.pdf

*BH, SNCR, and DLI equipment has been online at Huntley, units 67 & 68, since January 2009. At Dunkirk, equipment is functioning on units 3 and 4 and will be online on units 1 and 2 by the end of 2009. Source: Department of Environmental Conservation (DEC)

New York's installed coal capacity has been in a gradual state of decline over the past decade. In the past 10 years, 2,041 MW of coal capacity has been either retired or removed from New York's generation inventory. Of this amount, 1,088 MW of summer capacity was retired: Beebee (80 MW); Russell (260 MW); Lovett (378 MW); and Huntley, units 63-66 (371 MW). In addition, 953 MW of summer capacity from the Homer City, Pennsylvania station was also discontinued from New York's inventory in 1998.[21]

As coal electric generating capacity has declined in New York, so too has the amount of actual electricity generated. As shown in Table 10, both coal electric capacity and output peaked in 1989 at 4,852 MW and 31,586 gigawatt-hours (GWh), respectively. As recently as 1998, coal supply had remained fairly constant from the prior decade with 4,794 MW of installed capacity accounting for 30,590 GWh, 21 percent of State supply. By 2008, the remaining 3,055 MW of capacity accounted for 18,790 GWh of electricity generated (13 percent of total supply), a 38.6 percent decline in coal electricity production since 1998. For the summer 2009, the NYISO reports 2,711 MW of coal capacity, which is equal to seven percent of total summer system-wide capacity;[22] the 2009 output data will be available from the NYISO in April 2010.

Table 10. New York Coal Electric Summer Capacity (MW) and Output (GWh), 1983-2008

New York Coal Electric Summer Capacity and Output					
Year	**1983**	**1989**	**1998**	**2006**	**2008**
Capacity (MW)	3,383	4,852	4,794	3,419	3,055
Output (GWh)	19,940	31,586	30,590	20,683	18,790

Sources: New York Power Pool (NYPP). *Long Range Plan: Electricity Supply & Demand 1984 – 2000.* 1984.
NYPP. *Load & Capacity Data 1990 - 2006.* 1990.
NYPP. *1999 Load & Capacity Data.* 1999.
NYISO. *2007 Load & Capacity Data.* 2007.
http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2007_GoldBook_PUBLIC.pdf
NYISO. *2009 Load & Capacity Data "Gold Book."* 2009.
http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2009_LoadCapacityData_PUBLIC_Final.pdf

[21] NYPP. *1999 Load & Capacity Data.* 1999; NYISO. *2007 Load & Capacity Data.* 2007.
http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2007_GoldBook_PUBLIC.pdf;

NYISO. *2009 Load & Capacity Data "Gold Book."* 2009.
http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2009_LoadCapacityData_PUBLIC_Final.pdf

[22] NYISO. *2009 Load & Capacity Data "Gold Book."* 2009.

4 Environmental Factors

Coal combustion produces emissions of air pollutants including sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), carbon dioxide (CO_2), and mercury (Hg). SO_2, NO_x, and PM emissions are associated with air quality impacts and acidification of water resources, or acid rain. CO_2 emissions contribute to global climate change. Mercury, which can move in multiple environmental pathways, is a neurological toxin in humans and wildlife.

New York's SO_2 emissions from coal-fired plants have been reduced significantly as a result of a succession of increasingly stringent emission control programs. The first, initiated by New York, was the State Acid Deposition and Control Act (SADCA) implemented in 1984, which limited the sulfur content of fuels burned at power plants. Title IV of the federal Clean Air Act (CAA) amendments of 1990, implemented in two phases that became effective in 1995 and 2000, reduced total SO_2 emissions from New York's electricity generation plants by 50 percent from 1980 levels. NO_x emissions, which combine with volatile organic compounds (VOCs) in the presence of sunlight to form ozone or smog, substantially declined as a result of compliance with Title I of the federal CAA amendments. In the summer ozone seasons, May through September of 1995 and 1999, staged reductions in NO_x emissions of up to 55 percent for coal-fired plants were made. Most recently, New York implemented the Acid Deposition Reduction (ADR) Program, which contains the nation's most stringent SO_2 control requirements, targeted to reduce the State's emissions from power plants to 50 percent below the levels required by the federal CAA amendments of 1990. The ADR Program also requires plants to implement year-round controls for NO_x, a substantial extension of the five-month summer ozone season controls required under current federal regulations. The first full year of fully-implemented NO_x controls was 2005, and SO_2 controls were in place by January 2008.

Mercury emissions from coal vary significantly from plant to plant. Based on Department of Environmental Conservation (DEC) estimates, emission rates for mercury range from lows around 0.001 lbs per GWh for Greenidge and Somerset to highs of around 0.08 lbs per GWh for Huntley. By 2010, 6NYCRR Part 246 requires a monthly rolling average of no more than 0.057 lbs per GWh with a reduction to 0.003 lbs per GWh by 2015.

Table 11 shows average emission rates for SO_2, NO_x, CO_2, and Hg for the seven largest existing upstate coal plants in New York compared to estimated emission rates for coal plants that burn low-sulfur coal, plants with advanced emission controls, new coal plants based on emerging technologies, and, as a point of reference, new natural gas combined-cycle plants. The average emission rates for the largest upstate coal plants in New York exceed those for "next generation" coal plants, particularly with respect to SO_2, NO_x, and Hg. However, emission rates from all coal technologies listed in Table 11 are greater than combined cycle natural gas generation.

Table 11. Emission Rates for Electric Generation Plants (pounds per MWh and GWh)

Emission Rates for Electric Generation Plants				
Plant Type	**SO_2 lbs/MWh**	**NO_X lbs/MWh**	**CO_2 lbs/MWh**	**Hg lbs/GWh**
Existing New York Coal Plant (average) [1]	6.0	2.2	2,134	0.001 – 0.08
Existing New York Dual-Fuel Oil/Gas Steam Plant (average)[2]	3.0	1.5	1,445	0.0017[3]
New Advanced Coal: CFB[4]	1.61	0.600	1,912	0.009
New Advanced Coal: IGCC[5]	0.094	0.406	1,755	0.004
New Pulverized Coal (PC) – subcritical[6]	0.74	0.613	1,886	0.010
New PC – supercritical (SC)[7]	0.70	0.579	1,773	0.010
Natural Gas Combined-Cycle[8]	0.000	0.060	797	0.000
Oxycombustion - PC/SC with CCS (96.9% carbon capture efficiency) [9]	0.038	0.816	59	0.001
Oxycombustion - PC/SC with CCS (85.5% carbon capture efficiency) [9]	0.097	0.818	168	0.000

1. Average for the seven largest (by output) New York coal-powered electric generation plants for year 2007, including Cayuga, Greenidge, Somerset, Westover, Huntley, Danskammer, and Dunkirk. Excluding output from Russell and Lovett, now retired, these seven plants accounted for 95 percent of 2007 annual output. Emission data from the United States Environmental Protection Agency (EPA) Clean Air Markets Acid Rain Program. CO_2 calculation based on using a factor of 205.2 lbs of CO_2/MMBtu of fuel. MMBtu data from EPA Clean Air Markets Acid Rain Program. Calculation of emission per unit of output based on 2007 electrical generation data from NYISO, *Load and Capacity Report,* 2007. Mercury emission data provided by DEC. Mercury emissions vary significantly within New York.
2. Average for the seven largest (by output) New York oil//gas dual-fueled steam generation plants for year 2005, including Astoria, Poletti, Barrett, East River, Northport, Port Jefferson, and Ravenswood. Emission data from eGRID.
3. Source: EPA. *Air Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units -- Final Report to Congress Volume 1*. 1998. Total mercury emission factor weighs a 0.0027 lb/GWh mercury emission factor for oil generation with the fuel mix average for the New York plants. Fuel mix average for the seven plants was 61.6 percent oil and 38.4 percent natural gas.

For footnotes 4-8, emissions are based on: DOE National Energy Technology Lab. *Cost and Performance Baseline for Fossil Energy Plants*. 2007. All scenarios include Best Available Control Technologies (BACT) including Fluidized Gas Desulfurization (FGD).

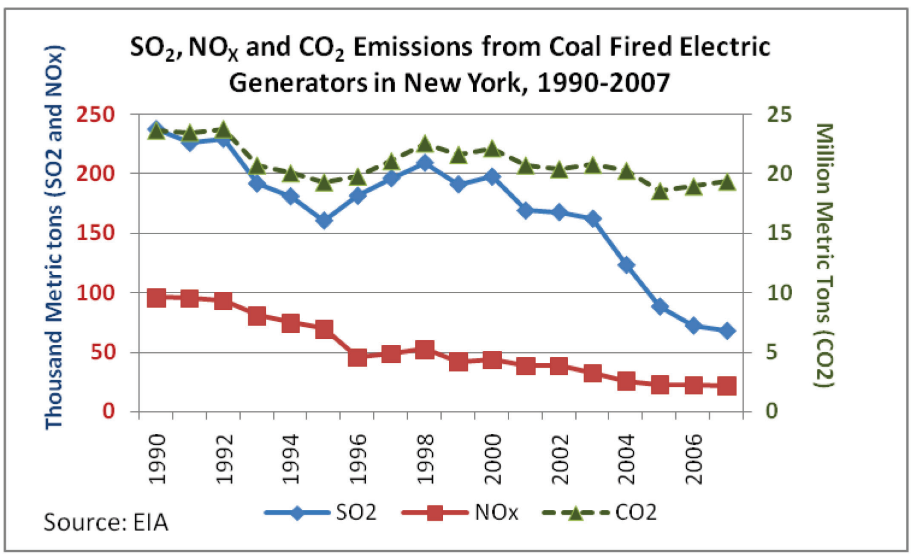
4. Circulating Fluidized Bed combustion
5. Integrated Gasification Combined Cycle, 770 MWe (electric), 80 percent capacity factor
6. Pulverized Coal, Subcritical, 583 MWe, 85 percent capacity factor
7. Pulverized Coal, Supercritical, 580 MWe, 85 percent capacity factor
8. Natural Gas Combined Cycle, 570 MWe, 85 percent capacity factor
9. DOE. National Energy Technology Lab. *Pulverized Coal Oxycombustion Power Plants, Vol 1. Bituminous Coal to Electricity Final Report* 2008. The emissions presented above (Cases 5B and 5C from Report) are based on a 550 MWe net output basis Rankine cycle plant employing pulverized bituminous coal, supercritical steam, and cryogenic air separation unit, BACT pollution control equipment including FGD and assumes that non-carbon emissions are not co-sequestered with CO_2.

A wide range of control technologies can be employed to reduce emissions of particulates, mercury, sulfur dioxide, and oxides of nitrogen. Particulates are captured with baghouses (BH), electrostatic precipitators (ESP), and multiclones (MC). Nitrogen oxides (NO_x) compliance actions may include a mix of combustion control technologies, such as low-NO_x burners (LNB) and overfire air (OFA), and end-of-pipe emission control technologies, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). Sulfur dioxide (SO_2) compliance actions may include switching to lower-sulfur coal, retirements, and installation of various scrubber technologies, such as flue gas desulfurization (FGD), dry lime injection (DLI), and spray dry injector (SDI). Burning low-sulfur coal, such as western subbituminous coal, can reduce SO_2 emissions from an uncontrolled plant by two-thirds; installing a scrubber can reduce emissions by 90 percent or more. Mercury can be reduced to a limited extent by conventional SO_2 scrubbers; more advanced controls specifically designed to reduce mercury include carbon injection (CI) and baghouse (BH) equipment.

Carbon capture and sequestration (CCS) technologies are under evaluation for their potential for removing the CO_2 emissions from coal-fired power plants. The commercially available method for capturing CO_2 from a conventional pulverized coal-fired boiler is the use of an amine-based system to absorb CO_2 from the flue gas stream, and its subsequent regeneration to produce a nearly pure product stream. An alternative method, known as oxycombustion, to capture CO_2 is to use oxygen rather than air as the oxidant in the combustion process that yields a flue gas stream comprised primarily of CO_2 and H_2O. By removing the water, a nearly pure CO_2 stream can be produced. CCS emissions associated with an oxycombustion pulverized coal plant are characterized in Table 11 above.

As shown in Figure 3, NO_x and SO_2 emissions have declined significantly in New York since 1990. Retirements, installation of environmental controls, as well as the conversion to low-sulfur coal, have helped to accomplish these reductions. Aggregate CO_2 emissions from coal generators have also declined over the time period from 1990 to 2007.

Figure 3. SO_2, NO_x, and CO_2 Emissions from Coal-Fired Electric Generators, 1990-2007 [23]



[23] This does not include coal cogeneration or combined heat and power plants in New York.

Coal combustion produces significant quantities of solid waste by-products, that can be put to beneficial use, subject to approval by DEC. Coal combustion waste products can be used as an ingredient in the manufacture of cement, asphalt, roofing shingles, gypsum, calcium chloride, lightweight aggregate, lightweight block, and low-strength backfill. DEC estimates that out of 617,000 tons of combustion by-products generated in 2007, 472,000 tons, or 76 percent, were reused.[24] There are no approved coal ash ponds in New York, such as the one that failed at a Tennessee Valley Authority facility in 2008. All facilities in New York dispose of their combustion wastes that are not beneficially used in approved landfills.

4.1 Federal Initiatives

The Energy Policy Act of 2005 (EPACT05) authorized $200 million annually from 2006 to 2014 for federal government cost-share programs to conduct demonstrations of commercial-scale advanced clean coal technologies. Further, it authorized a $3 billion commercial deployment program in the form of loans, cost sharing, and/or cooperative agreements to encourage new sources of advanced clean coal and to upgrade existing coal plants with retrofits and pollution control equipment; $1.1 billion was allocated over three years for U.S. Department of Energy (DOE) clean coal research and development program; and $90 million was allocated over three years for DOE to develop carbon-capture technologies that can be applied to the existing coal fleet. A loan guarantee program was established to provide incentives for innovative energy technologies that are improvements on currently employed technologies and that help to avoid, reduce, or sequester air pollutants. Tax credits were also specified in EPACT05 including a 20 percent credit, capped at $800 million, towards the construction of integrated coal gasification combined cycle (IGCC) and advanced combustion technologies. A similar credit, capped at $350 million, was created for certified industrial gasification projects. Finally, it authorized a seven-year amortization recovery period for the cost of certain certified air pollution control facilities used in connection with coal electric generation plants that were not in operation prior to 1976.

The Clean Coal Power Initiative (CCPI) was created to provide government co-financing for new coal technologies that can help utilities cut sulfur, nitrogen and mercury pollutants from power plants and also includes projects that reduce greenhouse emissions by boosting the efficiency by which coal plants convert coal to electricity or other energy forms. A third round CCPI solicitation was released in 2008 and focused on developing projects that utilize carbon sequestration technologies and/or beneficial reuse of carbon dioxide.

The American Recovery and Reinvestment Act of 2009 added an additional $800 million to funding for the third round and on June 9, 2009 DOE issued an amended application due date of August 24, 2009. The amendment also incorporates special provisions of the Recovery Act. [25]

The United States Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR) caps emissions of SO_2 and NO_x across 28 eastern states and the District of Columbia. This rule will achieve the largest reduction in air pollution in more than a decade, by reducing SO_2 emissions in these states by 73 percent and NO_x emissions by 61 percent from 2003 levels. The rule will create an emissions allowance trading market for power generators to make the reductions. Nevertheless, the rule has undergone several court challenges that have been alternately struck down and then reversed. On July 11,

[24] DEC, Bureau of Solid Waste, Reduction and Recycling. *Coal Ash Generation Annual Report*. 2007.

[25] DOE. *Clean Coal Technology and the Clean Coal Power Initiative*. http://fossil.energy.gov/programs/powersystems/cleancoal

2008, the U.S. District Court of Appeals for the District of Columbia Circuit struck down the rule as "fundamentally flawed" in answer to lawsuits by some utilities opposed to CAIR's SO_2 and NO_x emission allowance distributions. However, in December 2008, the Court remanded CAIR to EPA for revision, without vacature of the rule. The Court concluded: "Here, we are convinced that, notwithstanding the relative flaws of CAIR, allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR."[26]

A related action is the EPA Clean Air Mercury Rule, the first-ever federally mandated requirement that coal-fired electric utilities reduce their emissions of mercury. This rule is currently under review by EPA.

4.2 New York Initiatives

Under the Regional Greenhouse Gas Initiative (RGGI), 10 northeast states have implemented a cap-and-trade program intended to lower carbon dioxide (CO_2) emissions, the primary contributor to global climate change. This is the first mandatory cap-and-trade program for CO_2 emissions in U.S. history. In addition to New York, other states signing the regional Memorandum of Understanding for RGGI are Connecticut, Delaware, Maine, New Hampshire, New Jersey, Maryland, Massachusetts, Rhode Island, and Vermont. The cap-and-trade system uses credits or allowances to limit the total amount of emissions. CO_2 emissions from power plants in the region are capped at approximately 188 million tons annually, with this cap remaining in place until 2015. The states would then begin reducing emissions incrementally over a four-year period to achieve a 10 percent reduction by 2019.

All fossil fuel-fired generators in New York will be required to offset their CO_2 emissions through the purchase of credits that will be sold in quarterly regional auctions. Since coal generally does not operate or dispatch at the margin, as natural gas does particularly in the downstate region, the market clearing price for electricity during peak hours will generally be a function of natural gas or oil prices plus the cost to offset carbon emissions from the on-margin power plants. This added cost of production may lift the market clearing price for electricity, but not so much as to allow coal generators to completely recover their carbon offset costs since natural gas generation produces electricity at a lower emissions rate per unit of output than coal. Therefore, in-state coal generators will likely see their revenues rise, but less than the increase in operating costs including fuel and emission credits.

In June 2008, Governor Paterson announced $6 million in seed funding for an advanced CCS demonstration project in Jamestown, New York (Jamestown Project). The project has been developed by the "Oxy Coal Alliance", which is a consortium of private companies, whose members include the Jamestown Board of Public Utilities, Air Products, Dresser-Rand Group, Inc., Ecology and Environment, Inc., AES Eastern Energy, Foster Wheeler North America Corp., Shaw Power Group, Schlumberger, and Consol Energy. The Alliance has support from the Electric Power Research Institute, the New York State Museum, and the New York State Energy Research and Development Authority (NYSERDA), and is seeking a large federal grant worth potentially hundreds of millions of dollars under DOE's CCPI.

The Jamestown Project is a 50MW demonstration plant with combined heat and power (CHP) in the Jamestown municipal utility, conducted with the Oxy-Coal Alliance. The proposed Jamestown plant is a circulating fluidized bed plant that would employ an innovative technology known as "oxy-fuel." Prior to combustion, the incoming air into this plant would pass through a separation unit that would strip out atmospheric nitrogen, leaving a nearly pure oxygen stream. This would mix with recirculated flue gas

[26] U.S. Court of Appeals for the District of Columbia Circuit. No. 05-1244. December 23, 2008.

and be used to combust coal in a boiler. The resulting waste stream would then be treated to remove ash, SO_2 and CO_2. Because nitrogen is removed prior to combustion, there are no NO_x emissions. The remaining mercury would be removed prior to the purification of the CO_2. Waste from the CO_2 purification process would be neutralized and disposed of in the appropriate manner. The Jamestown Project would also be a test bed for CCS. Because this technology would be modular, it could potentially be scaled upward as high as 600MW at other locations. The build date is projected for 2011 with an operation date of 2013.

5 Emerging Coal Generation Technologies

Pulverized coal system (PC) is the conventional coal burning technology, used in more than 1,000 coal-fired power plants in the United States, in which finely ground coal is combusted to make steam that turns turbines and generates electricity.[27] The raw coal is fed into the pulverizer along with air heated to approximately 650˚F from the boiler.[28] As the coal is pulverized, the hot air dries it and blows the usable fine coal powder out to be used as fuel. The powdered coal is then blown directly to a burner in the boiler. The burner mixes the powdered coal in the air suspension with additional pre-heated combustion air and forces it out of a nozzle similar in action to fuel being atomized by an automotive fuel injector. Under normal operating conditions, there is enough heat in the combustion zone to ignite all the incoming fuel.

As environmental emission regulations have been tightened, many coal plants have employed a range of operational modifications and capital equipment investments. In addition to fuel switching, i.e., low-sulfur coal, technologies are available and emerging to reduce emissions from coal burning at three different stages: pre-combustion, combustion, and post-combustion. Pre-combustion cleaning involves the removal of impurities from coal with physical, chemical or biological processes. Advanced combustion processes include improvements in existing coal combustion processes and new processes that remove pollutants from coal as it is burned. Post-combustion cleaning involves the removal of pollutants from the downstream flue gas after combustion and before exiting the stack. Many of the post-combustion pollution control technologies have been widely commercialized and have evolved into proven, mature technologies.

Most advanced coal technologies are the products of research conducted over the last 25 years. In recent years, technological advancements have led to substantial reductions in the cost of controlling SO_2 and NO_x emissions. Some of the most successful advancements are low-NO_x burners, Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), and scrubbers. Advanced pollution controls installed on existing power plants or engineered into new facilities can provide effective and low cost ways to reduce sulfur dioxide and nitrogen emissions.

Advanced power generation technologies are complete electric power generating systems that offer superior efficiency and environmental performance over conventional coal-burning systems. These new processes, such as circulating fluidized bed (CFB) combustion, can improve both efficiency and emission control. Another category of advanced coal technologies involves the conversion of coal into another form of fuel, e.g., gas or liquid. In most of these cases, the new fuel form provides both energy and environmental benefits by reducing the pollutants emitted from combusting the new fuel as compared to coal. Integrated gasification combined cycle (IGCC) is an example of this type of technology.

Development and implementation of advanced coal technologies can be a significant contributor to achieving the State’s energy, economic, and environmental goals. Advanced coal combustion

[27] Coal is pulverized into a fine powder to improve efficiency and ease combustion.

[28] The feeding rate of coal is controlled by computers; it varies according to the boiler demand and the amount of air available for drying and transporting the pulverized coal fuel.

technologies can provide opportunities for repowering or upgrading existing coal-fired electricity generating facilities, maximizing use of the in-place infrastructure.

5.1 Circulating Fluidized Bed (CFB)

CFB combustion evolved from efforts to control pollutant emissions without external emission controls, such as scrubbers. The CFB technology suspends solid fuels on upward-blowing jets of air during the combustion process, resulting in a turbulent mixing of gas and solids. The tumbling action, much like a bubbling fluid, provides more effective chemical reactions and heat transfer. The technology allows burning at temperatures well below the threshold where NO_x form. In addition, the mixing action of CFB brings the flue gases into contact with a sulfur-absorbing chemical, such as limestone or dolomite, capturing more than 95 percent of the sulfur pollutants inside the boiler. The popularity of fluidized bed combustion is due not only to its capability of meeting SO_2 and NO_x emission standards without the need for expensive add-on controls but also technology's fuel flexibility. Almost any combustible material, from coal to municipal waste, can be used for fuel. Most boiler manufacturers currently offer this technology as a standard package.

5.2 Integrated Gasification Combined Cycle

Another emerging combustion technology, integrated gasification combined cycle (IGCC), converts coal to a gaseous form similar to natural gas before being burned. This advanced technology converts coal into a combustible synthetic gas by reaction with oxygen and heat/steam. Emissions from these plants are very low compared to other coal technologies because the gas is cleaned prior to combustion, burned in a gas turbine, and the resulting exhaust gases are used to produce steam that then drives a steam turbine. Typically 60 to 70 percent of the power comes from the gas turbine with IGCC. The result is an IGCC configuration that provides ultra-low pollution levels and, in addition, carbon-capture technologies can more readily be built on to the back end of IGCC plants than traditional pulverized coal combustion technologies.

On the front end of IGCC is a gasification technology. Worldwide, there are 117 operating plants that include 385 gasifiers. Of this, coal supplies 49 percent of the gasified fuel. Oil makes up 37 percent and other fuels including pet coke, biomass, waste, and natural gas make up the remainder. Products from the syn-gas produced from gasification include chemicals, liquid fuels, and electric power.

Only a handful of gasification plants have been constructed with combined cycle power generators. Some examples include:

- 250 MW unit, Polk Power Station, Tampa Electric, completed in 1996
- 253 MW plant, Nuon Power, Netherlands, completed in 1993
- 262 MW Wabash River Plant, Indiana, completed in 1995
- 330 MW plant, Puertollano, Spain, completed in 1997

In recent years, several IGCC plants have been proposed, including AEP's 630 MW plant, Southern Energy's 285 MW plant, and Duke Energy Indiana's 630 MW plant.

5.3 Super Critical Steam

The use of supercritical (SC) and ultra-supercritical (USC) steam, heated to a higher temperature than conventional boilers, has the potential to achieve greater generation efficiency, resulting in more output per unit of fuel as well as fewer pollutants. Efficiencies of 40 percent and higher have been demonstrated. SC and USC plants require the use of more durable metals and alloys in order to withstand the higher operating temperatures. Although several SC and USC coal plants have been constructed and operated in the United States, some have experienced operating difficulties due to the high tolerances required. In more recently constructed plants in Japan and elsewhere, anecdotal reports indicate that SC and USC plants have operated more reliably with fewer outages than earlier designs.[29]

5.4 Oxycombustion (Oxy-Coal)[30]

Oxycombustion, or oxy-coal, proposed to be used by the Jamestown Project discussed earlier, involves the combustion of coal in a mixture of oxygen and recirculated flue gas. The main benefits of oxycombustion technology with CCS are:

- Reduction of carbon dioxide emissions up to nearly 96.9 percent removal
- Reduction of SO_2
- Potential for enhancement of mercury removal in the baghouse and advanced SO_2 controls

Because it uses conventional equipment already proven in the power generation industry, the oxycombustion technology can readily be applied to new coal-fired power plants. Plant control during startup, shutdown, and load following is very similar to a conventional PC plant. Finally, the key process principles have been proven in the past including air separation and flue gas recycle (FGR).

However, several challenges to oxycombustion have also been identified:

- Air infiltration into the boiler dilutes the resulting flue gases. This could potentially be minimized by improved boiler materials, sealants, control technologies, and membranes.
- Combustion of fuels in a purified oxygen stream would occur at temperatures too high for existing boiler or turbine materials. This issue is being addressed by diluting the oxygen via the FGR, which results in an increase of the auxiliary power load and decreases efficiency. Further developments aim at increasing the efficiency of the FGR and improved boiler materials.
- The current capital and operating costs of specialized components are high.
- Plant efficiency is reduced by the use of the auxiliary load of FGR and air separation equipment. In models employed the DOE National Energy Technology Laboratory, net plant heat rates (HHV) for modeled PC oxycombustion plants with carbon capture ranged from 10,353 (33.0 percent net efficiency) to 11,655 (29.3 percent net efficiency) Btu/kWh. This resulted in net plant efficiencies for oxycombustion ranging from 29.3 to 33.0 percent. In comparison, net plant heat

[29] International Energy Agency. *Fossil Fuel-Fired Power Generation: Case Studies of Recently Constructed Coal and Gas-Fired Power Plants.* 2007. http://www.iea.org/textbase/nppdf/free/2007/fossil_fuel_fired.pdf

[30] DOE. National Energy Technology Lab. *Pulverized Coal Oxycombustion Power Plants, Volume 1: Bituminous Coal to Electricity Final Report.* 2008. http://www.netl.doe.gov/energy-analyses/pubs/PC%20Oxyfuel%20Combustion%20Revised%20Report%202008.pdf

rates in the base case analyses for commercially available air-fired SC and advanced next-generation USC plants were 8,662 (39.4 percent net efficiency) and 7,654 (44.6 percent net efficiency) Btu/kWh, respectively.[31] As a result of these efficiency losses, oxycombustion PC plants with CCS burn more coal and emit higher net emissions of NO_x per MWh than conventional PC plants without CCS.

[31] DOE. National Energy Technology Lab. *Pulverized Coal Oxycombustion Power Plants, Volume 1: Bituminous Coal to Electricity Final Report.* 2008. http://www.netl.doe.gov/energy-analyses/pubs/PC%20Oxyfuel%20Combustion%20Revised%20Report%202008.pdf

6 New York Coal Forecast Summary

As discussed in the Electricity Assessment: Modeling, the modeling analysis developed two reference cases to be used as points of reference for estimating the impacts of potential policy directions and/or system changes. The two reference cases differ only in the electricity demand forecasts, both developed by the New York Independent System Operator (NYISO), used as model inputs. The *Starting Point* reference case is based on the NYISO's 2009 Reliability Needs Assessment (RNA), which included achievement of approximately 27 percent of the '15 by 15' policy goal associated with the Energy Efficiency Portfolio Standard (EEPS) by 2015. From 2009 to 2018, electricity demand is assumed to increase at an average rate of 0.8 percent per year, or a total increase of 7.3 percent over this period. In comparison, the *SEP Policy* reference case is based on an electricity demand forecast that assumes full implementation of the '15 by 15' policy goal, which requires that electricity demand be reduced by 2015 to a level that is 15 percent lower than the forecasted level without the policy goal. From 2009 to 2018, electricity demand is assumed to decrease by a total of 1.8 percent.

Table 12 and Table 13 provide the coal demand forecasts under the *Starting Point* and *SEP Policy* reference cases.[32] Under both reference cases, coal demand is projected to decline over the planning period from 2009 to 2018. Overall coal demand is projected to decline by 4.8 percent to 5.4 percent. Industrial demand is also projected to decline by 6.8 TBtu, or 13.9 percent from 2009 to 2018. Coal demand from electricity generation is projected to decline by 5.6 TBtu under the *SEP Policy* reference case and 7.2 TBtu under the *Starting Point* reference case. The two reference cases project an overall decline in coal demand in New York ranging from 12.3 TBtu to 13.8 TBtu for the *Starting Point* and *SEP Policy* reference cases, respectively.

Table 12. Coal Demand by Sector, 2009-2018, Starting Point Reference Case

Coal Demand by Sector (TBtu)						Electric Sector Price $/MMBtu (Constant 2009 dollars)
Year	Residential	Commercial	Industrial	Electricity	Total	
2009	0.28	2.61	48.07	205.82	256.78	$2.85
2012	0.28	2.61	45.13	200.97	248.99	$2.67
2015	0.28	2.61	42.14	198.46	243.50	$2.62
2018	0.28	2.61	41.38	198.67	242.94	$2.56

[32] See the Electricity Assessment: Modeling for additional modeling information.

Table 13. Coal Demand by Sector, 2009-2018, SEP Policy Reference Case

Coal Demand by Sector (TBtu)						Electric Sector Price $/MMBtu (Constant 2009 dollars)
Year	**Residential**	**Commercial**	**Industrial**	**Electricity**	**Total**	
2009	0.28	2.61	48.07	205.78	256.74	$2.85
2012	0.28	2.61	45.13	200.25	248.27	$2.66
2015	0.28	2.61	42.14	198.49	243.52	$2.60
2018	0.28	2.61	41.38	200.15	244.43	$2.56