Coal Market Module

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The NEMS Coal Market Module (CMM) provides projections of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, Coal Market Module of the National Energy Modeling System 2014, DOE/EIA-M060(2014) (Washington, DC, 2014).

Key assumptions

Coal production

The coal production submodule of the CMM generates a different set of supply curves for the CMM for each year of the projection. Combinations of 14 supply regions, nine coal types (unique groupings of thermal grade and sulfur content), and two mine types (underground and surface), result in 41 separate supply curves. Supply curves are constructed using an econometric formulation that relates the minemouth prices of coal for the supply regions and coal types to a set of independent variables. The independent variables include: capacity utilization of mines, mining capacity, labor productivity, the user cost of capital of mining equipment, the cost of factor inputs (labor and fuel), and other mine supply costs.

The key assumptions underlying the coal production modeling are:

- As capacity utilization increases, higher minemouth prices for a given supply curve are projected. The opportunity to add capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80% range. Likewise, if capacity utilization falls, mining capacity may be retired. The amount of capacity that can be added or retired in a given year depends on the level of capacity utilization, the supply region, and the mining process (underground or surface). The volume of capacity expansion permitted in a projection year is based upon historical patterns of capacity additions.
- Between 1980 and 2000, U.S. coal mining productivity increased at an average rate of 6.6% per year, from 1.93 to 6.99 short tons per miner per hour. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining [1]. Since 2000, however, growth in overall U.S. coal mining productivity has been negative, declining at a rate of 2.4% per year to 5.19 short tons per miner-hour in 2012. By region, productivity in all but one (Alaska/Washington) of the coal producing basins represented in the CMM has declined some during the past 12 years. In the Central Appalachian coal basin, which has been mined extensively, productivity declined by 52% between 2000 and 2012, corresponding to an average decline of 5.9% per year. While productivity declines have been more moderate at the highly productive mines in Wyoming's Powder River Basin, coal mining productivity in this region still fell by 32% between 2000 and 2012 corresponding to an average rate of decline of 3.1% per year. Of the coal producing regions, the Eastern Interior has shown the best overall performance with coal mining productivity declining by only 9% between 2000 and 2012, or 0.8% per year. The Eastern Interior region, which has a substantial amount of thick, underground-minable coal reserves, is currently experiencing a resurgence in coal mining activity with several coal companies either opening or in the process of opening new, highly-productive longwall mines.
- Over the projection period, labor productivity is expected to decline in most coal supply regions, reflecting the trend of the previous decade. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.
- In the CMM, different rates of productivity improvement are assumed for each of the 41 coal supply curves used to represent U.S. coal supply. These estimates are based on recent historical data and expectations regarding the penetration and impact of new coal mining technologies. Data on labor productivity are provided on a quarterly and annual basis by individual coal mines and preparation plants on the U.S. Department of Labor, Mine Safety and Health Administration's Form 7000-2, "Quarterly Mine Employment and Coal Production Report," and the U.S. Energy Information Administration's Form EIA-7A, "Coal Production and Preparation Report". In the Reference case, overall U.S. coal mining labor productivity declines at rate of 1.2% per year between 2012 and 2040. Reference case projections of coal mining productivity by region are provided in Table 12.1.

Table 12.1. Coal mining productivity by region
short tons per miner hour

Supply Region	2012	2020	2025	2030	2035	2040	Average Annual Growth 12-40
Northern Appalachia	3.08	2.60	2.46	2.31	2.22	2.13	-1.3%
Central Appalachia	2.01	1.34	1.12	0.93	0.85	0.77	-3.4%
Southern Appalachia	1.68	1.33	1.22	1.12	1.05	0.99	-1.9%
Eastern Interior	4.29	4.39	4.38	4.40	4.39	4.39	0.1%
Western Interior	2.20	1.68	1.50	1.34	1.25	1.15	-2.3%
Gulf Lignite	6.93	6.14	5.84	5.55	5.36	5.18	-1.0%
Dakota Lignite	11.56	10.24	9.74	9.26	8.94	8.64	-1.0%
Western Montana	14.50	11.52	11.45	11.02	10.36	9.98	-1.3%
Wyoming, Northern Powder River Basin	29.17	24.01	22.15	20.43	19.33	18.29	-1.7%
Wyoming, Southern Powder River Basin	32.30	26.59	24.53	22.63	21.41	20.26	-1.7%
Western Wyoming	6.73	6.03	5.68	5.05	4.48	4.29	-1.6%
Rocky Mountain	5.50	4.09	3.62	3.20	2.97	2.74	-2.5%
Arizona/New Mexico	7.93	7.72	7.57	6.87	6.69	6.56	-0.7%
Alaska/Washington	5.98	6.35	6.51	6.67	6.77	6.88	0.5%
U.S. Average	5.19	4.64	4.35	4.02	3.81	3.68	-1.2%

Source: U.S. Energy Information Administration, *AEO2014* National Energy Modeling System run REF2014.D102413A.

- In the AEO2014 Reference case, the wage rate for U.S. coal miners increases by 0.9% per year and mine equipment costs are assumed to remain constant in 2012 dollars (i.e., increase at the general rate of inflation) over the projection period.

Coal distribution

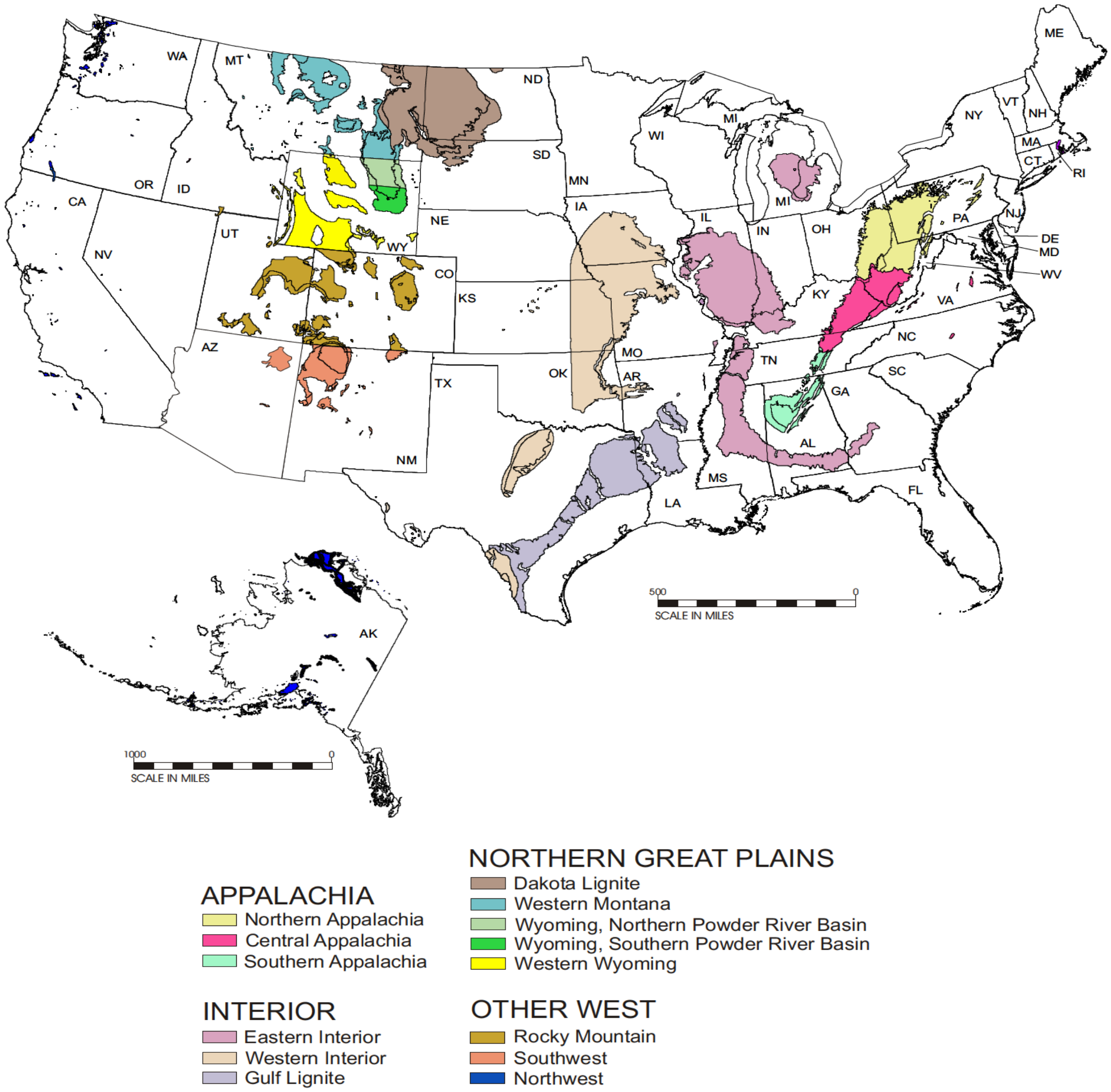
The coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector using a linear programming algorithm. Production and distribution are computed for 14 supply (Figure 11) and 16 demand regions (Figure 12) for 49 demand subsectors.

The projected levels of coal-to-liquids, industrial steam, coking, and commercial/institutional coal demand are provided by the liquid fuel market, industrial, and commercial demand modules, respectively; electricity coal demands are projected by the Electricity Market Module (EMM) coal imports and coal exports are projected by the CMM based on non-U.S. supply availability, endogenously determined U.S. import demand, and exogenously determined world coal import demands (non-U.S.).

The key assumptions underlying the coal distribution modeling are:

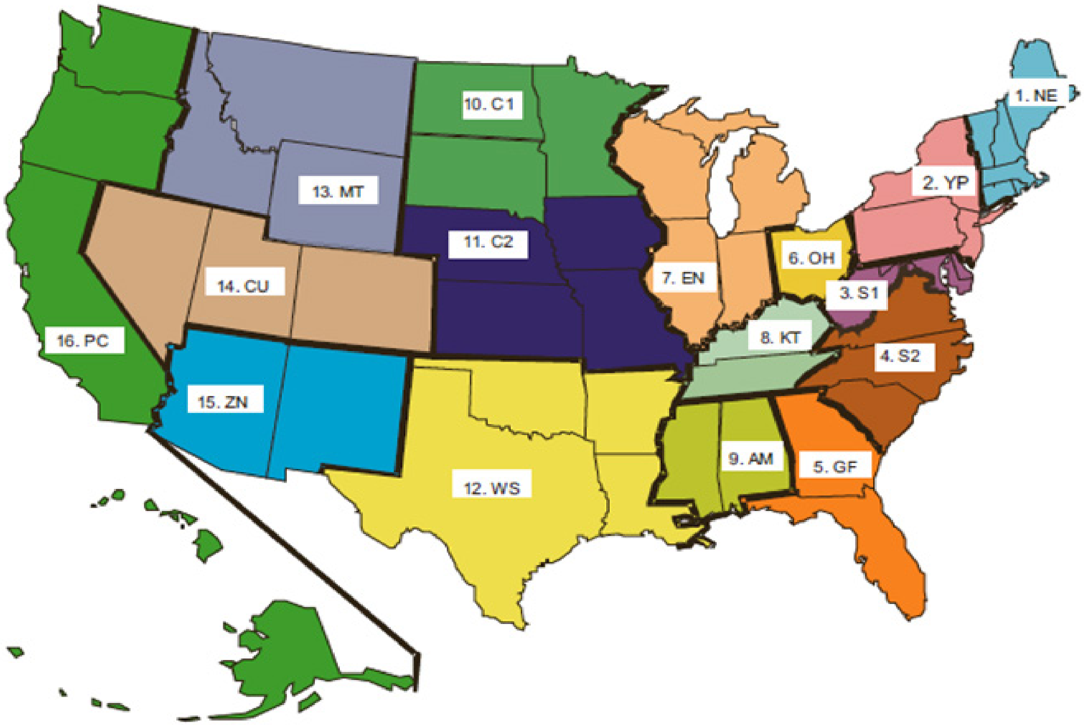
- Base-year (2012) transportation costs are estimates of average transportation costs for each origin-destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average minemouth price for a supply curve. Delivered price data are from Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users", Form EIA-5, Quarterly Coal Consumption and Quality Report, Coke Plants", Form EIA-923, "Power Plant Operations Report", and the U.S. Bureau of the Census, "Monthly Report EM-545". Minemouth price data are from Form EIA-7A, "Coal Production and Preparation Report".
- For the electricity sector only, a two-tier transportation rate structure is used for those regions which, in response to rising demands or changes in demands, may expand their market share beyond historical levels. The first-tier rate is representative of the historical average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier is also used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use. This cost is estimated at $0.10 per million Btu (2000 dollars) [2].

Figure 11. Coal Supply Regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure 12. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA, FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis.

- Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (east and west) transportation indices. The indices, calculated econometrically, are measures of the change in average transportation rates for coal shipments on a tonnage basis, which occurs between successive years for coal shipments. An east index is used for coal originating from coal supply regions located east of the Mississippi River while a west index is used for coal originating from coal supply regions located west of the Mississippi River. The east index is a function of railroad productivity, the user cost of capital for railroad equipment, and national average diesel fuel price. The user cost of capital for railroad equipment is calculated from the producer price index (PPI) for railroad equipment, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10%), less any capital gain associated with the worth of the equipment. In calculating the user cost of capital, three percentage points are added to the cost of borrowing in order to account for the possibility that a national level program to regulate greenhouse gas emissions may be implemented in the future. The west index is a function of railroad productivity, investment, and the western share of national coal consumption. The indices are universally applied to all domestic coal transportation movements within the CMM. In the AEO2014 Reference case, both eastern and western coal transportation rates are projected to remain near their 2012 levels in 2012 dollars.

- For the projection period, the explanatory variables are assumed to have varying impacts on the calculation of the indices. For the west, investment is the analogous variable to the user cost of capital of railroad equipment. The investment value and the PPI for rail equipment, which is used to derive the user cost of capital, increase with an increase in national ton-miles (total tons of coal shipped multiplied by the average distance). Increases in investment (west) or the user cost of capital for railroad equipment (east) cause projected transportation rates to increase. For both the east and the west, any related financial savings due to productivity improvements are assumed to be retained by the railroads and are not passed on to shippers in the form of lower transportation rates. For that reason, transportation productivity is held flat for the projection period for both regions. For the projection period, diesel fuel is removed from the equation for the east in order to avoid double-counting the influence of diesel fuel costs with the impact of the fuel surcharge program. The transportation rate indices for seven AEO2014 cases are shown in Table 12.2.

Table 12.2. Transportation rate multipliers
constant dollar index, 2012=1.000

Scenario	Region:	2012	2020	2025	2030	2035	2040
Reference Case	East	1.0000	1.0224	1.0121	1.0086	1.0074	1.0083
	West	1.0000	1.0051	1.0140	1.0117	1.0036	0.9964
Low Oil Price	East	1.0000	1.0182	1.0091	1.0045	1.0003	1.0053
	West	1.0000	1.0125	1.0250	1.0303	1.0177	1.0148
High Oil Price	East	1.0000	1.0360	1.0175	1.0122	1.0137	1.0156
	West	1.0000	0.9943	1.0038	1.0002	0.9944	1.0025
Low Economic Growth	East	1.0000	1.0294	1.0195	1.0186	1.0214	1.0028
	West	1.0000	1.0008	1.0043	1.0019	0.9952	0.9857
High Economic Growth	East	1.0000	1.0177	1.0076	1.0036	1.0027	1.0037
	West	1.0000	1.0141	1.0229	1.0223	1.0152	1.0053
Low Coal Cost	East	1.0000	0.9600	0.9000	0.8500	0.8000	0.7600
	West	1.0000	0.9400	0.9000	0.8500	0.8000	0.7500
High Coal Cost	East	1.0000	1.0900	1.1200	1.1700	1.2100	1.2600
	West	1.0000	1.0700	1.1300	1.1700	1.2100	1.2500

Source: Projections: U.S. Energy Information Administration, National Energy Modeling System runs REF2014.D102413A, LOWPRICE.D120613A, HIGHPRICE.D120613A, LOWMACRO.D112913A, HIGHMACRO.D112913A, LCCST14.D120413A, and HCCST14.D120413A. Based on methodology described in Coal Market Module of the National Energy Modeling System 2014, DOE/EIA-M060(2014) (Washington, DC, 2014).

- Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs have been passed on to shippers. While the programs vary in their design, the Surface Transportation Board (STB), the regulatory body with limited authority to oversee rate disputes, recommended that the railroads agree to develop some consistencies among their disparate programs and likewise recommended closely linking the charges to actual fuel use. The STB cited the use of a mileage-based program as one means to more closely estimate actual fuel expenses.
- For AEO2014, representation of a fuel surcharge program is included in the coal transportation costs. For the west, the methodology is based on BNSF Railway Company's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $1.25 per gallon. For every $0.06 per gallon increase above $1.25, a $0.01 per carload mile is charged. For the east, the methodology is based on CSX Transportation's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $2.00 per gallon. For every $0.04 per gallon increase above $2.00, a $0.01 per carload mile is charged. The number of tons per carload and the number of miles vary with each supply and demand region combination and are a pre-determined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate. For every projection year, it is assumed that 100% of all coal shipments are subject to the surcharge program.

- Coal contracts in the CMM represent a minimum quantity of a specific electricity coal demand that must be met by a unique coal supply source prior to consideration of any alternative sources of supply. Base-year (2012) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by generators on the Form EIA-923, "Power Plant Operations Report". Coal contracts are specified by CMM supply region, coal type, demand region, and whether or not a unit has flue gas desulfurization equipment. Coal contract quantities are reduced over time on the basis of contract duration data from information reported on the Form EIA-923, "Power Plant Operations Report", historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.
- Coal-to-liquids (CTL) facilities are assumed to be economic when low-sulfur distillate prices reach high enough levels. These plants are assumed to be co-production facilities with generation capacity of 832 megawatts (MW) (295 MW for the grid and 537 MW to support the conversion process) and the capability of producing 48,000 barrels of liquid fuels per day. The technology assumed is similar to an integrated gasification combined cycle, first converting the coal feedstock to gas, and then subsequently converting the syngas to liquid hydrocarbons using the Fisher-Tropsch process. Of the total amount of coal consumed at each plant, 40% of the energy input is retained in the product with the remaining energy used for conversion and for the production of power sold to the grid. For AEO2014, coal-biomass-to-liquids (CBTL) are not modeled. CTL facilities produce paraffinic naptha used in plastics production and blendable naptha used in motor gasoline (together about 28% of the total by volume) and distillate fuel oil (about 72%).

Coal imports and exports

Coal imports and exports are modeled as part of the CMM's linear program that provides annual projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The CMM projects steam and metallurgical coal trade flows from 17 coal-exporting regions of the world to 20 import regions for two coal types (steam and metallurgical). It includes five U.S. export regions and four U.S. import regions. The linear program determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting U.S. import demand and a pre-specified set of regional coal import demands. It does this subject to constraints on export capacity and trade flows.

The key assumptions underlying coal export modeling are:

- Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruptions, even though this may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.
- Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

The data inputs for coal trade modeling are:

- World steam and metallurgical coal import demands for the AEO2014 cases (Tables 12.3 and 12.4). U.S. coal exports are determined, in part, by these estimates of world coal import demand.
- Step-function coal export supply curves for all non-U.S. supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.
- Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account typical vessel sizes and route distances in thousands of nautical miles between supply and demand regions.

Coal quality

Each year the values of base year coal production; heat, sulfur, and mercury content; and carbon dioxide emission factors for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the Form EIA-923, a survey of the origin, cost and quality of fossil fuels delivered to generating facilities, the Form EIA-3, which records the origin, cost, and quality of coal delivered to U.S. manufacturers, transformation and processing plants, and commercial and institutional users, and the Form EIA-5, which records the origin, cost and quality of coal delivered to domestic coke plants. Estimates of coal quality for the export sector are based on coal quality data collected on EIA surveys for domestic shipments. Mercury content data for coal by supply region and coal type, in units of pounds of mercury per trillion Btu, shown in Table 12.5, were derived from shipment-level data reported by electricity generators to the U.S. Environmental Protection Agency in its 1999 Information Collection Request. Carbon dioxide emission factors for each coal type, based on data published by the U.S. Environmental Protection Agency, are shown in Table 12.5 in units of pounds of carbon dioxide emitted per million Btu [3].

Table 12.3. World steam coal import demand by import region[1]

million metric tons of coal equivalent

	2012	2020	2025	2030	2035	2040
The Americas	30.8	29.3	28.7	29.4	32.2	32.9
United States[2]	6.4	0.8	0.4	0.0	0.8	0.0
Canada	3.5	2.0	1.2	0.7	0.7	0.7
Mexico	6.0	6.6	6.5	7.1	7.5	7.5
South America	14.9	19.9	20.6	21.6	23.2	24.7
Europe	165.9	188.5	185.8	181.7	176.7	172.6
Scandinavia	8.2	6.6	5.9	5.0	4.6	4.1
U.K./Ireland	36.0	29.2	26.4	24.6	22.8	20.1
Germany/Austria/Poland	39.3	38.8	37.8	36.8	35.8	34.8
Other NW Europe	15.4	21.6	20.5	19.5	18.5	17.5
Iberia	17.5	17.3	16.9	16.9	15.7	14.0
Italy	14.3	22.8	21.9	20.1	18.2	16.4
Med/E Europe	35.2	52.2	56.4	58.8	61.1	65.7
Asia	561.0	626.6	684.5	739.1	795.9	849.0
Japan	94.2	94.3	93.5	92.2	90.6	88.0
East Asia	123.9	129.0	134.4	136.5	144.5	149.9
China/Hong Kong	189.0	212.8	236.3	258.1	272.2	286.2
ASEAN	44.1	60.0	79.3	94.9	113.0	131.2
Indian Sub	109.8	130.5	141.0	157.4	175.6	193.7
TOTAL	757.7	844.4	899.0	950.2	1,004.8	1,054.5

[1]Import Regions: United States: East Coast, Gulf Coast, Northern Interior, Non-Contiguous; Canada: Eastern, Interior; South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other NW Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Med/E Europe: Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia,
Turkey; East Asia: North Korea, South Korea, Taiwan; ASEAN: Malaysia, Philippines, Thailand, Vietnam; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.

[2]Excludes imports to Puerto Rico and the U.S. Virgin Islands.

Notes: One "metric ton of coal equivalent" equals 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Table 12.4. World metallurgical coal import demand by import region[1]
million metric tons of coal equivalent

	2012	2020	2025	2030	2035	2040
The Americas	21.6	31.0	34.0	37.0	41.0	47.1
United States[2]	1.0	1.0	1.0	1.0	1.0	1.0
Canada	4.5	3.9	3.9	3.7	3.6	3.5
Mexico	1.0	1.5	1.5	1.5	1.5	3.1
South America	15.1	24.6	27.7	30.8	34.9	39.5
Europe	57.1	62.1	60.9	59.9	59.8	59.8
Scandinavia	2.9	2.7	2.7	2.7	2.7	2.7
U.K./Ireland	5.6	6.0	6.0	6.0	6.0	6.0
Germany/Austria/Poland	10.4	13.2	12.2	11.2	11.2	11.2
Other NW Europe	13.1	14.7	14.5	14.4	14.2	14.1
Iberia	2.2	3.9	3.8	3.8	3.6	3.5
Italy	7.1	7.4	7.3	7.2	7.3	7.3
Med/E Europe	15.8	14.2	14.4	14.6	14.8	15.0
Asia	193.9	240.3	256.7	266.3	274.0	280.0
Japan	70.5	79.0	77.2	74.8	71.9	67.1
East Asia	36.0	41.2	43.3	45.5	47.1	48.8
China/Hong Kong	52.0	60.9	63.0	65.0	67.2	69.5
ASEAN[3]	0.0	0.0	0.0	0.0	0.0	0.0
Indian Sub	35.4	59.2	73.2	81.0	87.8	94.6
TOTAL	272.6	333.4	351.6	363.2	374.8	386.9

[1] Import Regions: United States: East Coast, Gulf Coast, Northern Interior, Non-Contiguous; Canada: Eastern, Interior; South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other NW Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Med/E Europe: Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; East Asia: North Korea, South Korea, Taiwan; ASEAN: Malaysia, Philippines, Thailand, Vietnam; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2] Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[3] Malaysia, Philippines, Thailand, and Vietnam are not expected to import significant amounts of metallurgical coal in the projection.
Notes: One "metric ton of coal equivalent" equals 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Legislation and regulations

The AEO2014 is based on current laws and regulations in effect before September 30, 2013. The Mercury Air Toxics Standard MATS), finalized in December 2011, is included in the AEO2014 Reference case as is the Clean Air Interstate Rule (CAIR). MATS sets emissions limits for mercury, other heavy metals, and acid gases from coal and oil power plants that are 25 MW or greater. Since generators are expected to request one-year extensions for compliance, MATS is assumed to be fully in place by 2016 rather than 2015 as stated in the regulation.

CAIR is a cap-and-trade program that regulates sulfur dioxide and nitrous oxide (NO_x) emissions from fossil-fueled power plants with a nameplate capacity greater than 25 MW in 27 states and the District of Columbia. Initial implementation of CAIR for NO_X occurred in 2009 and for SO_2 in 2010, with both caps subject to further tightening in 2015. The AEO2014 includes trading and banking of allowances consistent with CAIR's provisions. States covered by CAIR can trade allowances amongst themselves or with non-CAIR states participating in the Clean Air Act Amendment Title IV program. Non-CAIR state allowances are considered less valuable than CAIR state allowances and are traded at a discounted rate.

Table 12.5. Production, heat content, sulfur, mercury and carbon dioxide emission factors by coal type and region

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2012 Production (million short tons)	Heat Content (million Btu per short ton)	Sulfur Content (pounds per million Btu)	Mercury Content (pounds per trillion Btu)	CO_2 (pounds per million Btu)
Northern Appalachia	PA, OH, MD, WV (North)	Metallurgical	Underground	22.4	26.30	0.88	N/A	204.7
		Mid-Sulfur Bituminous	All	31.5	25.19	1.39	11.17	204.7
		High-Sulfur Bituminous	All	71.8	24.67	2.76	11.67	204.7
		Waste Coal (Gob and Culm)	Surface	11.0	11.60	3.65	63.90	204.7
Central Appalachia	KY (East), WV (South), VA, TN (North)	Metallurgical	Underground	54.9	26.30	0.62	N/A	206.4
		Low-Sulfur Bituminous	All	10.2	24.72	0.54	5.61	206.4
		Mid-Sulfur Bituminous	All	82.8	24.66	0.95	7.58	206.4
Southern Appalachia	AL, TN (South)	Metallurgical	Underground	12.2	26.30	0.46	N/A	204.7
		Low-Sulfur Bituminous	All	0.2	26.20	0.50	3.87	204.7
		Mid-Sulfur Bituminous	All	7.0	24.43	1.37	10.15	204.7
East Interior	IL, IN, KY(West), MS	Mid-Sulfur Bituminous	All	7.5	22.51	1.21	5.60	203.1
		High-Sulfur Bituminous	All	120.0	22.75	2.66	6.35	203.1
		Mid-Sulfur Lignite	Surface	3.0	10.36	0.96	14.11	216.5
West Interior	IA, MO, KS, AR, OK, TX (Bit)	High-Sulfur Bituminous	Surface	1.6	21.25	1.44	21.55	202.8
Gulf Lignite	TX (Lig), LA	Mid-Sulfur Lignite	Surface	36.8	13.46	1.26	14.11	212.6
		High-Sulfur Lignite	Surface	11.4	11.99	2.65	15.28	212.6
Dakota Lignite	ND, MT (Lig)	Mid-Sulfur Lignite	Surface	27.8	13.21	1.29	8.38	219.3
Western Montana	MT (Bit & Sub)	Low-Sulfur Bituminous	Underground	5.7	19.81	0.50	5.06	215.5
		Low-Sulfur Subbituminous	Surface	14.7	18.10	0.38	5.06	215.5
		Mid-Sulfur Subbituminous	Surface	16.0	17.25	0.77	5.47	215.5
Wyoming, Northern PRB	WY (Northern Powder River Basin	Low-Sulfur Subbituminous	Surface	150.9	6.84	0.38	7.08	214.3
		Mid-Sulfur Subbituminous	Surface	2.4	16.22	0.68	7.55	214.3
Wyoming, Southern PRB	WY (Southern Powder River Basin)	Low-Sulfur Subbituminous	Surface	235.0	17.63	0.28	5.22	214.3

Table 12.5. Production, heat content, sulfur, mercury and carbon dioxide emission factors by coal type and region (cont)

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2012 Production (million short tons	Heat Content (million Btu per Short ton)	Sulfur Content (pounds per million Btu)	Mercury Content (pounds per trillion Btu)	CO_2 (pounds per million Btu)
Western Wyoming	WY (Other basins, excluding Powder River Basin)	Low-Sulfur Subbituminous	Underground	4.6	18.87	0.63	2.19	214.3
		Low-Sulfur Subbituminous	Surface	3.5	19.02	0.49	4.06	214.3
		Mid-Sulfur Subbituminous	Surface	4.9	19.54	0.79	4.35	214.3
Rocky Mountain	CO, UT	Metallurgical	Underground	0.1	26.30	0.43	N/A	209.6
		Low-Sulfur Bituminous	Underground	40.0	22.74	0.51	3.82	209.6
		Low-Sulfur Subbituminous	Surface	5.5	19.93	0.51	2.04	212.8
Southwest	AZ, NM	Low-Sulfur Bituminous	Surface	7.6	24.54	0.56	4.66	207.1
		Mid-Sulfur Subbituminous	Surface	17.4	17.98	0.91	7.18	209.2
		Mid-Sulfur Bituminous	Underground	5.0	19.07	0.79	7.18	207.1
Northwest	WA, AK	Low-Sulfur Subbituminous	Surface	2.1	16.02	0.29	6.99	216.1

N/A = not available.
Source: U.S. Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-7A, "Coal Production and Preparation Report", and Form EIA-923, "Power Plant Operations Report". U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM-545." U.S. Environmental Protection Agency, Emission Standards Division, Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort (Research Triangle Park, NC, 1999). U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008, ANNEX 2 Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2010), Table A-37, http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html.

The Energy Improvement and Extension Act of 2008 (EIEA) and Title IV, under Energy and Water Development, of the American Recovery and Revitalization Act of 2009 (ARRA), together, are assumed to result in the development of about 1 gigawatt of coal-fired generating capacity with carbon capture and sequestration by the end of 2018.

EIEA was passed in October 2008 as part of the Emergency Economic Stabilization Act of 2008. Subtitle B provides investment tax credits for various projects sequestering CO_2. Subtitle B of EIEA, which extends the payment of current coal excise taxes for the Black Lung Disability Trust Fund program of $1.10 per ton on underground-mined coal and $0.55 per ton on surface-mined coal from 2013 to 2018, is also represented in the AEO2014. Prior to the enactment of EIEA, contribution rates for the Black Lung Disability Trust Fund were to be reduced in 2014 to $0.50 per ton on underground-mined coal and to $0.25 per ton on surface-mined coal. Lignite production is not subject to the Black Lung Disability Trust Fund program's coal excise taxes.

Title IV under ARRA provides $3.4 billion for additional research and development on fossil energy technologies. This includes $800 million to fund projects under the Clean Coal Power Initiative (CCPI) program, focusing on projects that capture and sequester greenhouse gases or use captured carbon dioxide for enhanced oil recovery (EOR). The Hydrogen Energy California (HECA) project in Kern County, California and the Texas Clean Energy Project (TCEP) in Penwell, Texas include efforts to use captured carbon dioxide for EOR.

Title XVII of the Energy Policy Act of 2005 (EPACT2005) authorized loan guarantees for projects that avoid, reduce, or sequester greenhouse gasses. EPACT05 also provided a 20% investment tax credit for Integrated Coal-Gasification Combined Cycle (IGCC) capacity and a 15% investment tax credit for other advanced coal technologies. EIEA allocated an additional $1.25 billion in investment tax credits for IGCC and other advanced coal-based generation technologies. For the AEO2014, all of the EPACT 2005 and EIEA investment tax credits are assumed to have been fully allocated and, therefore, not available for new, unplanned capacity builds in the NEMS Electricity Market Module.

Beginning in 2008, electricity generating units of 25 megawatts or greater were required to hold an allowance for each ton of CO_2 emitted in nine Northeastern States as part of the Regional Greenhouse Gas Initiative (RGGI). The States currently participating in RGGI include Connecticut, Maine, Maryland, Massachusetts, Rhode Island, Vermont, New York, New Hampshire, and Delaware. RGGI is modeled in AEO2014 as an emissions reduction program for the Central Atlantic region. In the AEO2014, the impact on coal use is generally small, as the CO_2 allowance price remains relatively low in the projections.

The AEO2014 includes a representation of California Assembly Bill 32 (AB32), the California Global Warming Solutions Act of 2006, which authorized the California Air Resources Board (CARB) to set California's overall GHG emissions reduction goal to its 1990 level by 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California, including a cap-and-trade program. The cap-and-trade program features an enforceable cap on GHG emissions that will decline over time. In the AEO2014, an allowance price, representing the incremental cost of complying with AB32 cap-and-trade, is modeled in the NEMS Electricity Market Module via a region-specific emissions constraint. This allowance price increases the effective delivered price of coal, reducing its ability to compete with other generating sources such as natural gas which emits less CO_2 per unit of electricity produced.

In accordance with California Senate Bill 1368 (SB 1368), which established a greenhouse gas emission performance standard for electricity generation, the AEO2014 prohibits builds of new coal-fired generating capacity without carbon capture and storage (CCS) for satisfying electricity demand in California. SB 1368 limits the generating emissions rate for all power plants that California utilities build, invest in, or sign a long-term contract with to be no more than 1,100 pounds of CO_2 per megawatthour, which is the approximate emissions rate for a new natural gas combined-cycle power plant [4].

Coal alternative cases

Coal Cost cases

In the Reference case, coal mine labor productivity is assumed to decline on average by 1.2% per year from 2012 to 2040. Miner wage rates increase by about 0.9% per year, and mine equipment costs remain constant in 2012 dollars. Eastern and western coal transportation rates are projected to remain near their 2012 levels in 2012 dollars.

In two alternative coal cost cases, productivity, average miner wages, equipment cost, and transportation rate assumptions were modified for 2014 through 2040 in order to examine the impacts on U.S. coal supply, demand, distribution, and prices. The key modeling assumptions for the alternative Coal Cost cases and Reference case are shown in Table 12.6.

In the Low Coal Cost case, coal mine labor productivity is assumed to increase at an average rate of 1.0% per year from 2012 to 2040. Coal mining wages, mine equipment costs, and other mine supply costs all are assumed to be about 24% lower (in 2012 dollars) in 2040 in the Low Coal Cost case than in the Reference case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be approximately 25% lower by 2040. In the international coal market, the price change for non-U.S. export supplies (e.g., coal exported to the international market from ports in Australia) is assumed to be roughly 10% less than the price change projected for U.S. coal exports.

In the High Coal Cost case, coal mine labor productivity is assumed to decline at an average rate of 4.0% per year from 2012 to 2040. Coal miner wages, mine equipment costs, and other mine supply costs all are assumed to be about 31% higher in 2040 in real terms in the High Coal Cost case than in the Reference case. Compared to the Reference case, coal transportation rates are assumed to be approximately 25% higher by 2040. In the international coal market, the price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

No Greenhouse Gas Concern case

In the Reference case, to reflect the market reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital for investments in new coal-fired power and coal-to-liquids plants without carbon capture and sequestration technology is assumed. These assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs for new existing plants. This adjustment was first implemented for AEO2009. Beginning with AEO2012, a 3-percentage-point increase in the cost of capital for investments in retrofits at existing coal plants is also applied for emission control equipment (excluding CCS). The No GHG concern case excludes the 3-percentage point increase in the cost of capital.

Table 12.6. Key modeling assumptions for AEO2014 reference and coal cost cases
constant dollar index, 2012=1.000, unless otherwise noted

	2012	2020			2040			Growth Rate, 2012-2040		
		Low Cost	Reference	High Cost	Low Cost	Reference	High Cost	Low Cost	Reference	High Cost
Cost Indices										
Transportation Rte Multipliers										
Eastern Railroads	1.000	0.960	1.022	1.090	0.760	1.008	1.260	-1.0%	0.0%	0.8%
Western Railroad	1.000	0.940	1.005	1.070	0.750	0.996	1.250	-1.0%	0.0%	0.8%
Mine Equipment Costs										
Underground	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
Surface	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
Other Mine Supply Costs										
East of the Mississippi: All Mines	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
West of the Mississippi: Underground	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
West of the Mississippi: Surface	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
Coal Mining Labor Productivity (short tons per miner per hour)	1.000	5.52	4.64	3.85	6.89	3.68	1.68	1.0%	-1.2%	-4.0%
Average Coal Miner Wage (2012 dollars per year)	80,450	87,295	93,666	100,431	79,835	104,525	136,440	0.0%	0.9%	1.9%

Sources: 2012 data based on: U.S. Energy Information Administration (EIA), Annual Coal Report 2012, DOE/EIA-0584(2012) (Washington, DC, December 2013); and U.S. Department of Labor, Bureau of Labor Statistics, Quarterly Census of Employment and Wages: Coal Mining, Series ID : ENUUS0005052121; Projections: EIA, AEO2014 National Energy Modeling System runs LCCST14.D120413A, REF2014.D102413A, and HCCST14.D120413A.

Notes and sources

[1] Flynn, Edward J., "Impact of Technological Change and Productivity on The Coal Market," U.S. Energy Information Administration (Washington, DC, October 2000), http://www.eia.gov/oiaf/analysispaper/pdf/coal.pdf; and U.S. Energy Information Administration, The U.S. Coal Industry, 1970-1990: Two Decades of Change, DOE/EIA-0559 (Washington, DC, November 1992).

[2] The estimated cost of switching to subbituminous coal, $0.10 per million Btu (2000 dollars), was derived by Energy Ventures Analysis, Inc. and was recommended for use in the CMM as part of an Independent Expert Review of the Annual Energy Outlook 2002's Powder River Basin production and transportation rates. Barbaro, Ralph and Schwartz,Seth, Review of the Annual Energy Outlook 2002 Reference Case Forecast for PRB Coal, prepared for the Energy Information Administration (Arlington, VA: Energy Ventures Analysis, Inc., August 2002).

[3] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008, Annex 2 Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2010), Table A-37, http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html.

[4] California Energy Commission, SB 1368 Emission Performance Standards, http://www.energy.ca.gov/emission_standards/index.html.