Coal Market Module

The National Energy Modeling System (NEMS) Coal Market Module (CMM) provides projections of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM consists of three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM may be found in the U.S. Energy Information Administration (EIA) publication, *Coal Market Module of the National Energy Modeling System 2018*, DOE/EIA-M060 (2018) (Washington, DC).

Key assumptions

Coal production

The CMM generates different supply curves for each year of the projection period. 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 different supply curves. Supply curves are constructed using an econometric formulation that relates the minemouth prices of coal for each supply curve to a set of independent variables. The independent variables include capacity utilization of mines, mining capacity, labor productivity, the capital cost of mining equipment, the cost of factor inputs (labor and fuel), and other mine supply costs.

Key assumptions underlying the coal production modeling

- As capacity utilization increases, higher minemouth prices for a given supply curve are projected. The opportunity to add production capacity is allowed within the modeling framework if capacity utilization rises to a predetermined 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 supply region, the capacity utilization level, and the mining process (underground or surface). The volume of capacity expansion permitted in a projection year is based on historical patterns of capacity additions.
- The annual wage for U.S. coal miners averaged $87,363 in 2018 [1]. The *Annual Energy Outlook 2020* (AEO2020) assumes miner wages remain flat in real terms (i.e., increase at the general rate of inflation) at the 2017 wage level. Mine equipment costs are also assumed to remain constant at the 2017 level during the projection period. The equipment index is built from the U.S. Bureau of Labor Statistics series for *Mining machinery and equipment* for underground mining and *Construction machinery* for surface mining [2].
- In the CMM, different rates of labor productivity improvement or decline are assumed for each of the 41 coal supply curves used to represent U.S. coal supply. AEO2020 Reference case projections for regional coal mining productivity are provided in Table 1. Overall U.S. coal mining labor productivity declines at a rate of 2.0% per year between 2018 and 2050 in the Reference case. Higher stripping ratios at surface mines and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology in most coal supply regions. Individual coal mines and preparation plants provide historical data on labor productivity on a quarterly and annual basis on the U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, *Quarterly Mine*

Employment and Coal Production Report, and EIA's Form EIA-7A, *Annual Survey of Coal Production and Preparation*.

- Between 1980 and 2000, U.S. coal mining labor productivity increased at an average rate of 6.7% per year, from 1.93 to 7.02 short tons per miner-hour. The major factors underlying these gains were inter-fuel price competition, structural change in the industry, and technological improvements in coal mining [3]. Between 2000 and 2018, overall U.S. coal mining productivity year-over-year change has been negative in all CMM supply regions (except Eastern Interior) and has declined nationally at a rate of 0.8% per year to 6.05 short tons per miner-hour in 2018.
- Mine closures can sometimes result in small gains in regional productivity because the least productive mines are often those that suspend operation. On the other hand, highly productive mining operations can appear less productive when existing mine capacity is not fully utilized, as has been the case in recent years. In 2018, 4 out of 14 coal supply regions showed productivity increases from 2017 levels, while the other 10 showed declining productivity. Similarly, the 2018 national average coal mining labor productivity rate of 6.05 short tons per miner-hour reflected a 17% increase from the 2012 productivity rate of 5.19 tons per miner-hour, which was the lowest observed rate in more than 20 years.
- Productivity in some areas of the coal fields in the eastern United States is projected to decline as operations move from mature coal fields to marginal reserve areas. In the Central Appalachian coal basin, which has been mined extensively, productivity declined by more than 50% between 2000 and 2018, corresponding to an average decline of 4.2% per year. 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 2018, Central Appalachian productivity declined to 1.91 short tons per miner-hour. Furthermore, the Central Appalachian region is projected to have the fastest regional decline in productivity at 2.8% per year from 2018 to 2050.
- Although declines have been more moderate at the highly productive mines in Wyoming's Powder River Basin (PRB), coal mining productivity in this region still fell by 36% between 2000 and 2018, corresponding to an average rate of decline of 2.4% per year. For AEO2017 onward, productivity figures for the PRB production areas were modified based on an assessment of recent private sector analyses [4]. In AEO2020, productivity from 2018 to 2050 in northern and southern PRB is projected to decline at an average rate of 1.0% and 0.7% per year, respectively.
- The Eastern Interior has shown the most productivity growth; coal mining productivity grows by 17% between 2000 and 2017, or 0.9% 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, and several coal companies are operating highly productive longwall mines. Productivity is expected to increase modestly at a rate of 0.7% per year from 2018 to 2050.

Table 1. Coal mining productivity by region

short tons per miner-hour

Supply region	2018	2020	2025	2030	2040	2050	Average annual growth 2018–2050
Northern Appalachia	4.01	3.38	3.03	2.67	2.14	1.75	-2.6%
Central Appalachia	1.91	1.72	1.48	1.24	0.98	0.78	-2.8%
Southern Appalachia	2.16	2.10	1.92	1.75	1.54	1.37	-1.4%
Eastern Interior	5.23	5.31	5.54	5.73	6.13	6.51	0.7%
Western Interior	3.39	3.31	3.12	2.93	2.77	2.63	-0.8%
Gulf Lignite	5.97	5.85	5.56	5.29	4.92	4.58	-0.8%
Dakota Lignite	12.29	12.05	11.46	10.90	10.13	9.44	-0.8%
Western Montana	15.05	14.84	14.25	13.69	12.87	12.10	-0.7%
Wyoming, Northern Powder River Basin	30.48	29.48	28.07	27.86	23.24	22.28	-1.0%
Wyoming, Southern Powder River Basin	30.04	28.98	26.73	25.59	24.79	24.21	-0.7%
Western Wyoming	6.31	6.16	5.86	5.57	5.23	4.92	-0.8%
Rocky Mountain	5.26	4.81	4.24	3.74	3.15	2.68	-2.1%
Arizona/New Mexico	6.03	5.46	3.86	3.26	3.55	3.27	-1.9%
Alaska/Washington	5.00	5.05	5.15	5.25	5.37	5.48	0.3%
U.S. average	6.05	6.06	4.92	4.60	3.66	3.15	-2.0%

Source: U.S. Energy Information Administration, AEO2020 National Energy Modeling System run REF2020.D112119A

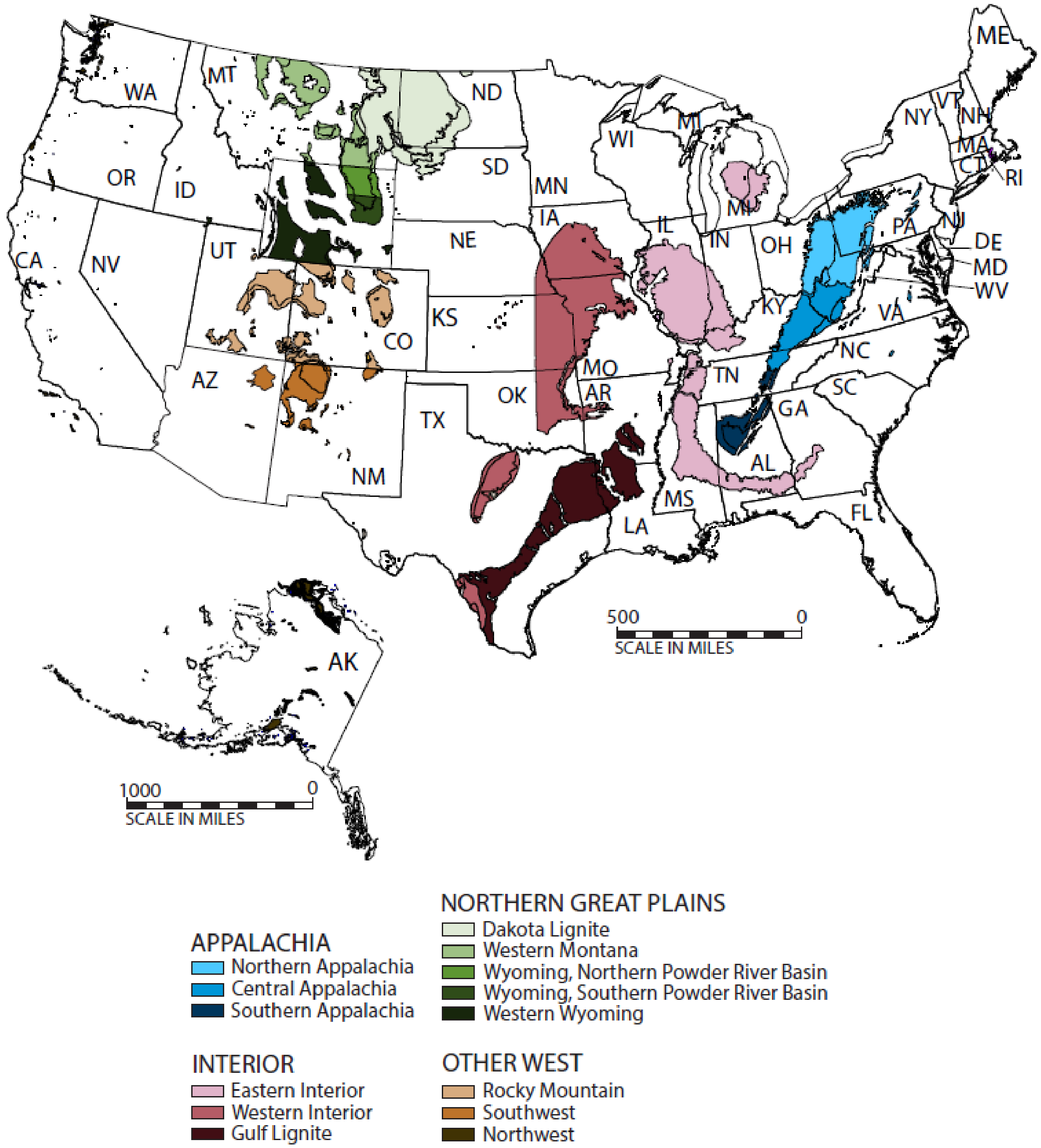
Coal distribution

The domestic coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) solution for coal transportation by supply region for a given set of coal demands in each demand sector by using a linear programming algorithm. Production and distribution are computed for 14 supply regions (Figure 1) and 16 demand regions (Figure 2) for 49 demand subsectors.

The liquid fuel market module provides projected levels of coal-to-liquids (CTL), the industrial module provides projected levels of industrial steam and coking, and the commercial demand module provides projected levels of commercial/institutional coal demand. The Electricity Market Module (EMM) projects electricity coal demands. Coal imports and coal exports are projected by the international coal distribution submodule of the CMM based on non-U.S. supply availability, endogenously determined U.S. import demand, and exogenously determined world (non-U.S.) coal import demands.

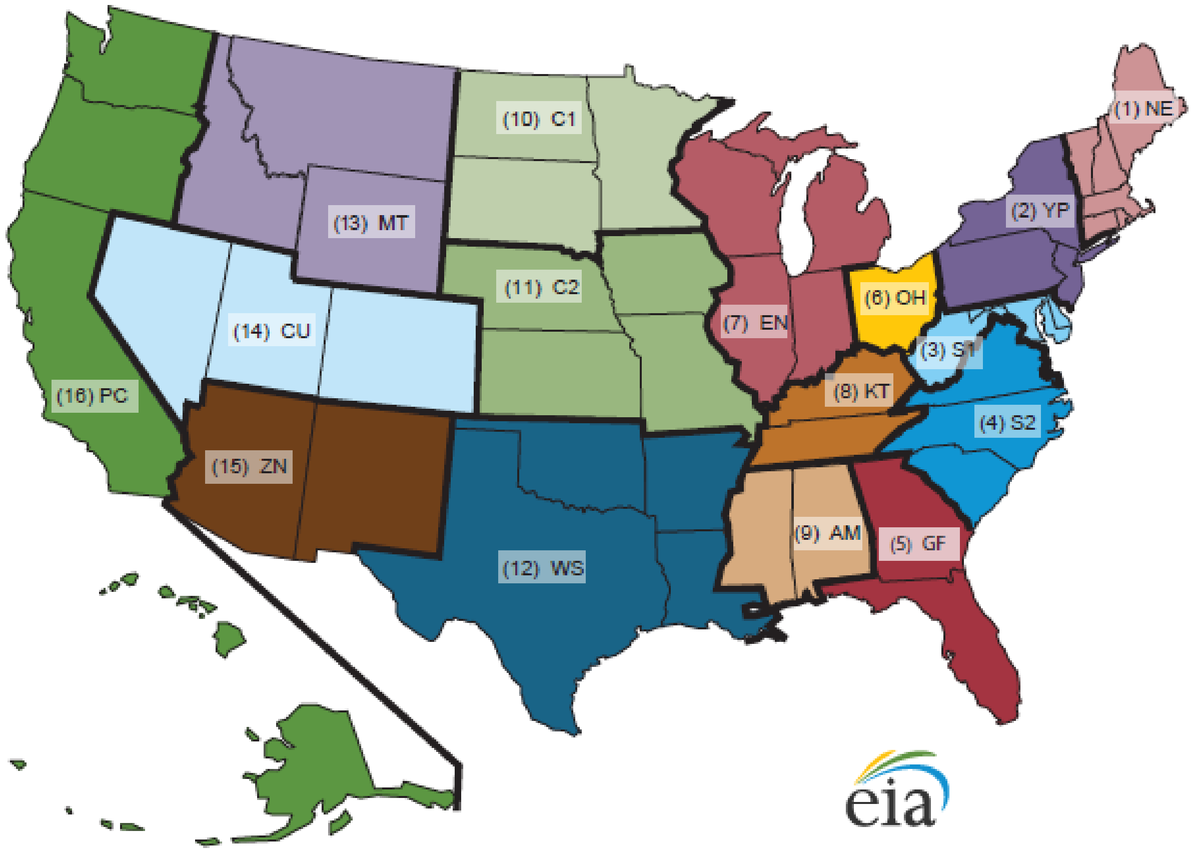
Transportation rates between coal supply and demand regions are determined by applying annual, projected regional transportation price indices to a two-tier rate structure. The first tier represents the historical average transportation rate that is estimated for a base year using recent EIA survey data. The second tier captures costs associated with changing patterns of coal demand for electricity generation. Regional fuel surcharges are then added to the indexed transportation rates to reflect the impact of higher diesel fuel costs.

Figure 1. Coal supply regions



Source: U.S. Energy Information Administration

Figure 2. Coal demand regions



Region	Code	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	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

Key assumptions underlying the coal distribution modeling

- Domestic transportation rates for coal are modeled as the average transportation costs for each supply origin-to-demand 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 Survey of Industrial, Commercial and Institutional Coal Users*, 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, *Annual Survey of Coal Production and Preparation*. The base year coal transport rates were updated for AEO2020 and are now based on 2018 data.
- For the electricity sector, a two-tier transportation rate structure is used for those regions which, in response to changing patterns of coal demand, may expand their market shares beyond historical levels. The first-tier rate represents the historical average transportation rate. The second-tier transportation rate captures the higher cost of expanded shipping distances in large demand regions. The second tier also captures costs associated with using subbituminous coal at units that were not originally designed for that use. This cost is estimated at $0.10 per million British thermal units (Btu) (2000$) [5].
- 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, measure the change in average transportation rates for coal shipments on a tonnage basis, which occurs each year for coal shipments. An east index is used for coal originating from coal supply regions located east of the Mississippi River, and a west index is used for coal originating from coal supply regions located west of the Mississippi River. The indices are universally applied to all domestic coal transportation movements within the CMM. In the AEO2020 Reference case, both eastern and western coal transportation rates are projected to decline from their 2018 levels. The transportation rate indices for seven AEO2020 cases are shown in Table 2, where the index value equals 1.0 for 2018.
- The east index in Table 2 is negatively correlated with improvements in railroad productivity, and it is positively correlated with the user cost of capital for railroad equipment and the national average diesel fuel price. The *user cost of capital* for railroad equipment is calculated from the producer price index (PPI) for railroad equipment. This cost also accounts for the *opportunity cost* of money used to purchase equipment and the depreciation for using the equipment (assumed at 10%), less any capital gain for the worth of the equipment. In calculating the user cost of capital, three percentage points are added to the cost of borrowing to account for the possibility that a national-level program to regulate greenhouse gas emissions may be implemented in the future. An increase in national ton-miles (total tons of coal shipped multiplied by the average distance) increases PPI and, consequently, the user cost of capital. Diesel fuel is removed from the equation for the east in the projection period to avoid double-counting the influence of diesel fuel costs with the impact of the fuel surcharge program.
- The west index is negatively correlated with improvements in railroad productivity and positively correlated with increases in investment and with the western share of national coal

consumption. The investment component provides a similar function as the user cost of capital of railroad equipment does in the east index and similarly increases with an increase in national ton-miles (total tons of coal shipped multiplied by the average distance).

- For both the East and the West, any related financial savings as a result of 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 this reason, transportation productivity is held flat during the projection period for both regions.

Table 2. Transportation rate multipliers

constant dollar index, 2018=1.0000

Case	Region	2018	2020	2025	2030	2040	2050
Reference	East	1.0000	0.9941	1.0141	1.0033	0.9824	0.9781
	West	1.0000	0.9859	0.9592	0.9586	0.9438	0.9446
Low Oil Price	East	1.0000	0.9917	1.0132	1.0081	0.9876	0.9761
	West	1.0000	0.9859	0.9650	0.9681	0.9567	0.9502
High Oil Price	East	1.0000	0.9993	1.0078	1.0041	0.9782	0.9693
	West	1.0000	0.9857	0.9473	0.9420	0.9362	0.9365
Low Economic Growth	East	1.0000	0.9949	1.0100	1.0112	0.9807	0.9654
	West	1.0000	0.9858	0.9499	0.9493	0.9392	0.9377
High Economic Growth	East	1.0000	0.9950	1.0169	0.9991	0.9834	0.9694
	West	1.0000	0.9858	0.9617	0.9595	0.9537	0.9591
High Oil & Gas Supply	East	1.0000	0.9948	1.0045	1.0057	0.9935	0.9858
	West	1.0000	0.9859	0.9470	0.9427	0.9356	0.9332
Low Oil & Gas Supply	East	1.0000	0.9952	1.0123	0.9936	0.9843	0.9741
	West	1.0000	0.9859	0.9725	0.9624	0.9563	0.9562

Source: Projections: U.S. Energy Information Administration, National Energy Modeling System runs REF2020.D111119A, LOWPRICE. D112619A, HIGHPRICE. D112619A, LOWMACRO. D1112619A, HIGHMACRO. D112619A, HIGHOILGASSUPPLY. D112619A, and LOWOILGASSUPPLY. D112619A. Based on methodology described in the Coal Market Module of the National Energy Modeling System 2018, DOE/EIA-M060 (2018) (Washington, DC)

- Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs are passed on to shippers. Although 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 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 AEO2020, a fuel surcharge program is represented 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 (gal). For every $0.06/gal increase that is higher than $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/gal. For every \$0.04/gal increase higher than \$2.00, a \$0.01/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 predetermined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate. For every projection year, 100% of all coal shipments are assumed to be 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 before considering any alternative sources of supply. Base-year (2018) coal contracts between coal producers and electricity generators are estimated based on 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 based on contract duration data from information reported on the Form EIA-923, historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.
- CTL facilities are assumed to be economical 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 are capable of producing 48,000 barrels per day of liquid fuels. The technology assumed is similar to an integrated gasification combined cycle: first the coal feedstock is converted into gas and then the syngas is converted into liquid hydrocarbons using the Fischer-Tropsch process. Of the total amount of coal consumed at each plant, 40% of the energy input is retained in the product and the remaining energy is used for conversion and production of power sold to the grid. For AEO2020, coal-biomass-to-liquids are not modeled. CTL facilities produce distillate fuel oil (about 72% of their output) and paraffinic naphtha used in plastics production and blendable naphtha used in motor gasoline (together about 28% of the total by volume).

Coal imports and exports

Coal imports and exports are modeled as part of the CMM's linear program that provides an annual projection 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), including 5 U.S.-export regions and 4 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 predetermined set of regional coal import demands, subject to constraints on export capacity and trade flows.

Key assumptions underlying coal export modeling

- Coal buyers (importing regions) tend to spread their purchases among several suppliers to reduce the impact of potential supply disruptions, even though this choice may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead try 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 only modestly affect world coking coal flows.
- U.S. coal exports for 2019 to 2020 are benchmarked to match export levels projected in the *Short-Term Energy Outlook* (STEO). Exports through 2050 are consistent with international coal trade assumed in EIA's *International Energy Outlook 2019* (IEO2019).

Data inputs for coal trade modeling

- World import demand for steam coal (Table 3) and metallurgical coal (Table 4) for the AEO2020 cases are input from previous analysis or projections. U.S. coal exports are determined, in part, by these estimates of world coal import demand. The assumed levels of international trade demand for AEO2020 are based on the long-term projections made in IEO2019.
- Step-function coal export supply curves for all non-U.S. supply regions are reviewed and updated when preparing the IEO projections. The curves provide estimates of export prices per metric ton, including minemouth and inland freight costs, as well as the capacities for each of the supply steps.
- Ocean transportation rates (in dollars per metric ton) are calculated for feasible coal shipment paths (routes) between international supply regions and international demand regions. An algorithm derives the rates based on input parameters for
    - Transport route distance in nautical miles between each international supply and demand region pair
    - Typical ship capacity (in lading tons) and vessel class (Panamax vs. Cape size) for dry bulk transport on each route
    - Annual daily hire rate by vessel class
    - Sailing speed, days in port, port costs, fuel consumption in port, and fuel consumption at sea by vessel class
    - Annual regional fuel prices used in dry bulk transport: bunker fuel/IFO380 (intermediate fuel oil with maximum viscosity of 380 centistokes, composed of about 90% residual oil and 10% distillate oil) and MGO (marine gasoil, a 100% distillate based fuel) on U.S. Gulf Coast fuel prices and price differentials to each supply region.

Table 3. World steam coal import demand by import region[1]

million metric tons of coal equivalent

	2018	2020	2025	2030	2035	2040	2050
The Americas	**39.4**	**43.7**	**43.1**	**46.0**	**47.9**	**49.8**	**54.0**
United States[2]	4.4	3.7	0.3	0.1	0.1	0.1	0.1
Canada	2.7	2.5	2.0	2.0	1.9	1.9	1.8
Mexico	9.6	9.9	10.3	10.6	10.8	11.0	11.4
South America	22.7	27.6	30.4	33.4	35.1	36.9	40.6
Europe	**130.5**	**121.4**	**117.6**	**115.9**	**114.5**	**113.2**	**114.8**
Scandinavia	4.5	3.2	2.8	2.7	2.5	2.4	2.4
United Kingdom/Ireland	5.9	4.2	2.8	2.7	2.5	2.4	2.4
Germany/Austria/Poland	19.9	19.0	16.9	16.0	15.2	14.5	14.2
Other northwestern Europe	21.4	17.6	15.7	14.9	14.1	13.4	13.2
Iberia	16.8	12.0	10.7	10.2	9.7	9.2	9.0
Italy	9.2	8.8	7.9	7.5	7.1	6.8	6.6
Mediterranean/eastern Europe	52.8	56.5	60.8	62.0	63.3	64.6	67.2
Asia	**595.1**	**579.0**	**621.4**	**670.8**	**731.9**	**794.7**	**1,064.3**
Japan	98.5	97.7	89.3	88.8	88.2	83.7	87.1
East Asia	139.2	102.7	104.8	109.7	117.5	118.1	139.0
China/Hong Kong	112.1	107.7	102.4	97.2	92.4	91.5	89.6
ASEAN[3]	91.2	96.2	115.4	123.5	132.2	145.4	192.3
Indian subcontinent	154.1	174.6	209.6	251.5	301.8	356.1	556.4
TOTAL	**765.0**	**744.0**	**782.0**	**832.7**	**894.3**	**957.7**	**1,233.1**

[1]Import regions: United States: East Coast, Gulf Coast, Northern Interior, Noncontiguous; Canada: Eastern, Interior; South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other northwestern Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Mediterranean and eastern 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 subcontinent: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[3]ASEAN=Association of Southeast Asian Nations. 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 British thermal units. Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, National Energy Modeling System run Ref2020.D112119A

Table 4. World metallurgical coal import demand by import region[1]

million metric tons of coal equivalent

	2018	2020	2025	2030	2035	2040	2050
The Americas	**22.4**	**25.7**	**28.0**	**29.5**	**31.1**	**32.9**	**36.7**
United States[2]	0.6	0.7	1.1	1.0	1.0	1.0	0.9
Canada	4.4	3.9	3.5	3.5	3.5	3.5	3.5
Mexico	0.7	1.2	1.6	1.6	1.6	1.6	1.6
South America	16.7	19.8	21.9	23.4	25.1	26.8	30.7
Europe	**57.5**	**58.0**	**55.8**	**55.6**	**55.3**	**55.1**	**54.7**
Scandinavia	3.2	2.9	2.8	2.8	2.8	2.8	2.8
United Kingdom/Ireland	3.0	3.4	3.0	3.0	3.0	3.0	3.0
Germany/Austria/Poland	6.5	7.1	6.3	6.3	6.3	6.3	6.3
Other northwestern Europe	20.1	19.1	17.5	17.1	16.8	16.5	15.8
Iberia	2.0	2.0	1.7	1.6	1.6	1.6	1.5
Italy	3.2	3.3	3.1	3.0	2.9	2.9	2.8
Mediterranean/eastern Europe	19.6	20.2	21.5	21.7	21.9	22.1	22.6
Asia	**224.6**	**240.8**	**261.9**	**271.9**	**289.2**	**310.7**	**378.4**
Japan	66.3	69.0	66.2	63.6	61.0	58.6	54.0
East Asia	45.1	47.1	49.1	50.1	51.1	52.1	54.2
China/Hong Kong	48.6	50.3	48.3	46.4	44.5	42.8	39.4
ASEAN[3]	9.2	9.1	11.0	11.5	12.1	12.7	14.0
Indian subcontinent	55.5	65.2	87.3	100.4	120.5	144.5	216.8
TOTAL	**304.5**	**324.5**	**345.6**	**357.0**	**375.6**	**398.6**	**469.9**

[1]Import regions: United States: East Coast, Gulf Coast, Northern Interior, Noncontiguous; Canada: Eastern, Interior; South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other northwestern Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Mediterranean and eastern 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 subcontinent: Bangladesh, India, Iran, Pakistan, Sri Lanka.

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

[3] ASEAN=Association of Southeast Asian Nations. 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 British thermal units. Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, National Energy Modeling System run Ref2020.D112119A

Coal quality

Each AEO cycle, the base-year coal production for each defined coal source is calibrated to survey data. In addition, the average values for heat content (million Btu per ton), sulfur content (pounds per million Btu), mercury content (pounds per trillion Btu), and carbon dioxide (CO2) emissions when burned (pounds per million Btu) are calculated to reflect the coal quality of each modeled coal source. Surveys used for this purpose are Form EIA-923, which collects the quantity, origin point, cost, and quality of fossil fuels delivered to generating facilities, and Form EIA-3, which collects the quantity, origin point, cost, and quality of coal delivered to U.S. commercial and institutional users and domestic coke plants. Coal quality for the export sector is based on data collected on Form EIA-7A for domestic production and is matched to export shipments collected by the U.S. Bureau of the Census on its *Monthly Report EM-545*. Mercury content data for coal by supply region and coal type, in units of pounds of mercury per trillion Btu, were derived from shipment-level data reported by electricity generators to the U.S.

Environmental Protection Agency (EPA) in its 1999 *Information Collection Request*. CO2 emission factors for each coal type, based on data published by EPA, are shown in Table 5 in pounds of CO2 emitted per million Btu [6].

Table 5. Production, heat content, sulfur, mercury, and carbon dioxide (CO2) emission factors by coal type and region

Coal supply region	States	Coal rank and sulfur level	Mine type	2018 production (million short tons)	2018 heat content (million British thermal units per short ton)	2018 sulfur content (pounds per million British thermal units)	Mercury content (pounds per trillion British thermal units)	CO2 (pounds per million British thermal units)
Northern Appalachia	Pennsylvania, Ohio, Maryland, and West Virginia (North)	Metallurgical	Underground	17.8	28.71	0.76	N/A	204.7
		Mid-sulfur bituminous	All	16.6	24.45	1.65	12.68	204.7
		High-sulfur bituminous	All	69.7	25.35	2.61	12.19	204.7
		Waste coal (gob and culm)	All	10.2	13.40	3.89	53.85	204.7
Central Appalachia	Kentucky (East), West Virginia (South), Virginia, and Tennessee (North)	Metallurgical	Underground	45.9	28.69	0.42	N/A	206.4
		Low-sulfur bituminous	All	14.7	25.73	0.51	5.02	206.4
		Mid-sulfur bituminous	All	17.9	24.53	0.92	8.58	206.4
Southern Appalachia	Alabama and Tennessee (South)	Metallurgical	Underground	15.6	28.69	0.51	N/A	204.7
		Low-sulfur bituminous	All	0.7	25.55	0.59	3.87	204.7
		Mid-sulfur bituminous	All	1.9	23.47	1.38	9.65	204.7
East Interior	Illinois, Indiana, Kentucky (West), and Mississippi	Mid-sulfur bituminous	All	27.9	22.39	1.93	7.35	203.1
		High-sulfur bituminous	All	78.5	23.08	2.54	7.51	203.1
		Mid-sulfur lignite	Surface	3.0	10.64	0.93	25.30	216.5
West Interior	Iowa, Missouri, Kansas, Arkansas, Oklahoma, and Texas	High-sulfur bituminous	Surface	0.8	23.49	1.05	10.45	202.8
Gulf Lignite	Texas and Louisiana	Mid-sulfur lignite	Surface	22.7	13.28	1.05	11.56	212.6
		High-sulfur lignite	Surface	6.3	11.79	3.72	15.28	212.6
Dakota Lignite	North Dakota and Montana	Mid-sulfur lignite	Surface	30.4	13.88	1.20	7.76	219.3
Western Montana	Montana	Low-sulfur bituminous	Underground	0.2	20.63	0.44	3.86	215.5

Table 5. Production, heat content, sulfur, mercury, and carbon dioxide (CO2) emission factors by coal type and region (cont.)

Coal supply region	States	Coal rank and sulfur level	Mine type	2018 production (million short tons)	2018 heat content (million British thermal units per short ton)	2018 sulfur content (pounds per million British thermal units)	Mercury content (pounds per trillion British thermal units)	CO2 (pounds per million British thermal units)
Western Montana (cont)	Montana	Low-sulfur subbituminous	Surface	17.2	18.32	0.37	7.52	215.5
		Mid-sulfur subbituminous	Surface	10.8	17.01	0.78	6.00	215.5
Wyoming, Northern PRB	Wyoming (Northern Powder River Basin)	Low-sulfur subbituminous	Surface	99.9	16.83	0.37	8.17	214.3
		Mid-sulfur subbituminous	Surface	2.2	16.29	0.64	11.87	214.3
Wyoming, Southern PRB	Wyoming (Southern Powder River Basin)	Low-sulfur subbituminous	Surface	186.8	17.64	0.26	7.37	214.3
Wyoming	Wyoming (non-Powder River Basin)	Low-sulfur bituminous	Underground	2.3	18.42	0.64	2.19	214.3
		Low-sulfur bituminous	Surface	4.0	19.47	0.56	1.90	214.3
		Mid-sulfur subbituminous	Surface	4.5	19.16	0.76	4.35	214.3
Rocky Mountain	Colorado and Utah	Metallurgical	Surface	0.1	28.69	0.43	N/A	209.6
		Low-sulfur bituminous	Underground	22.9	22.55	0.40	5.35	209.6
		Low-sulfur subbituminous	Surface	3.8	20.31	0.58	2.04	212.8
Southwest	Arizona and New Mexico	Low-sulfur bituminous	Surface	6.6	21.49	0.55	6.00	207.1
		Mid-sulfur subbituminous	Surface	9.1	18.32	1.08	13.98	209.2
		Mid-sulfur bituminous	Underground	3.0	19.73	0.68	7.18	207.1
Northwest	Washington and Alaska	Low-sulfur subbituminous	Surface	0.6	15.25	0.19	5.69	216.1

N/A = not available

[1] No production of this coal type in this region after 2013. Displayed values are from 2013.

Sources: U.S. Energy Information Administration, Form EIA-3, *Quarterly Survey of Industrial, Commercial & Institutional Coal Users*; Form EIA-7A, *Annual Survey of Coal Production and Preparation*; and Form EIA-923, *Power Plant Operations Report*. U.S. Department of Commerce, U.S. Census Bureau, *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: 1990-2009 ANNEX 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2011), Table A-37

Legislation and regulations

AEO2020 is based on current laws and regulations in effect as of September 30, 2019. The CMM models compliance with emissions limits established by the Clean Air Act Amendments of 1990 (CAAA90). The two provisions with the greatest relevance to coal are the Mercury and Air Toxics Standards (MATS) and the Cross-State Air Pollution Rule (CSAPR).

MATS, which was finalized in December 2011, sets emissions limits for mercury, other heavy metals, and acid gases from coal- and oil-fired power plants that are 25 MW or larger. MATS compliance is assumed to be fully in place based on the 2016 deadline for compliance after allowing for one-year extensions from the 2015 base compliance year specified in the regulation. Retrofit decisions in the EMM are the primary means of compliance for MATS, but the CMM also includes transportation cost adders for removing mercury using activated carbon injection.

CSAPR [7] replaced the previous Clean Air Interstate Rule (CAIR) [8] cap-and-trade program at the start of 2015. CSAPR requires fossil fuel-fired electric generating units in 27 states to restrict emissions of sulfur dioxide (SO_2) and nitrogen oxide, which are precursors to the formation of fine particulate matter ($PM_{2.5}$) and ozone. The CMM sets regional limits (constraints) throughout the projection for SO_2 based on annual allowance set by EPA under CSAPR. The sulfur content for U.S. coal produced in 2015 is displayed in Table 5 along with heat content, mercury content, and average CO_2 emissions.

The Energy Improvement and Extension Act of 2008 passed in October 2008 as part of the Emergency Economic Stabilization Act of 2008~~—~~which extended 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 through 2018~~—~~is also represented in AEO2020. The coal excise tax rates are scheduled to decline to $0.50 per ton for underground mines and to $0.25 per ton for surface mines on January 1, 2019. Lignite production and coal intended for export from the United States are not subject to the Black Lung Disability Trust Fund program's coal excise taxes [9].

Several polices and regulations modeled in the EMM have implications for coal-fired generating capacity additions, retirements, and generation, including

- EPA New Source Performance Standards under CAAA90 Section 111(b)
    - The proposed revision to the original 2015 rule announced by EPA in December 2018 amended the finding that partial carbon capture and storage (CCS) was the "best system of emission reduction" (BSER) for greenhouse gas emissions from new coal generating units, replacing it instead with the most efficient demonstrated steam cycle (i.e., supercritical conditions for large steam units) as BSER.
    - By withdrawing its previous ruling, EPA has affirmed its intention that new coal plants without CCS can be built if economical, using supercritical (including ultra-supercritical) technology.
    - EIA accommodated these changes to the original 2015 rule by including an option to install supercritical coal generating units without CCS for new generation.

- EPA issued the Affordable Clean Energy (ACE) [10] rule on June 19, 2019, to replace the Clean Power Plan (CPP):
    - The ACE rule revises EPA's BSER finding for greenhouse gas emissions from existing power plants to include only heat-rate efficiency improvements and gives states a list of *candidate technologies* that can be used to establish performance standards for use in state plans, rather than setting specific technology-based standards,
    - EIA modeled the ACE rule in the Electricity Markets Module (EMM) by offering existing coal generating units the choice to either upgrade to a heat rate improvement (HRI) option identified in EIA's CPP study or retire by 2025; this approach relies on the 2015 EIA study of HRI potential and costs for existing coal units
- Regional Greenhouse Gas Initiative (RGGI)
- Renewable portfolio standard (RPS) programs
- State-level Zero-Emission Credit (ZEC) programs in Illinois, New Jersey, New York, and Ohio
- State of California Greenhouse Gas (GHG) emission reduction policies [11], [12], [13], [14]

A discussion of the assumptions used to model the effects of these policies and regulations is provided in the EMM Assumptions document.

Notes and sources

[1] Quarterly Census of Employment and Wages - Bureau of Labor Statistics, Series: "Private, NAICS 2121 Coal mining, All States and U.S." Supply region and US average weighted by production and labor hours from EIA-7A "Annual Survey of Coal Production and Preparation." https://www.eia.gov/Survey/#eia-7a

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[6] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, Annex 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2011), Table A-37, https://www.epa.gov/sites/production/files/2015-12/documents/us-ghg-inventory-2011-complete_report.pdf

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[9] U.S. Department of Interior, Office of Natural Resources Revenue, "How it Works: Coal Excise Tax" (Washington, D.C.: Accessed February 2, 2019). https://revenuedata.doi.gov/how-it-works/coal-excise-tax/

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[11] AB-398 California Global Warming Solutions Act of 2006: market based compliance mechanisms. (State of California) https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398

[12] SB-32 California Global Warming Solutions Act of 2006: emissions limit. (State of California, September 08, 2016). https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB32

[13] California Energy Commission, SB 1368 Emission Performance Standards, (State of California) https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/emission-performance-standards-sb-1368.

[14] SB-100 California 100 Percent Clean Energy Act of 2018: California Renewables Portfolio Standard Program: emissions of greenhouse gases. (State of California September 10, 2018). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100