



Assumptions to the Annual Energy Outlook 2025: Coal Market Module

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Table of Contents

Coal Market Module 1

 Key assumptions 1

 Coal distribution 3

 Coal transportation 6

 Coal imports and exports 9

 Coal quality..... 9

Legislation and regulations 11

 Cross-State Air Pollution Rule 11

 Mercury and Air Toxics Standards 11

Notes and Sources 11

Table of Figures

Figure 1. Coal supply regions 2

Figure 2. Coal demand regions 5

Table of Tables

Table 1. Coal mining productivity by supply curve 3

Table 2. Coal transportation rate multipliers..... 7

Table 3. Rail cost adjustment factor (RCAF) shares and escalator basis..... 8

Table 4. Production, heat content, sulfur, mercury, and CO₂ emission factors by coal region, rank, and mine type 10

Coal Market Module

The National Energy Modeling System's (NEMS) Coal Market Module (CMM) projects U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM consists of three functional areas: coal production, coal distribution, and coal exports. You can find a detailed description of the CMM in our publication, [Coal Market Module of the National Energy Modeling System: Model Documentation 2022, DOE/EIA-M060 \(2022\)](#) (Washington, DC).

Key assumptions

Coal production

Domestic coal supply is represented by supply curves, where the price of coal affects the quantity of coal supplied annually. The supply curves are positive and upward sloping, indicating a direct correlation between price and quantity supplied. As the price increases, coal production also increases. As a non-homogenous commodity, coal produced at two different mines will have different chemical properties, so consumers may want different types of coal based on their different energy needs. For modeling purposes, the CMM generates 14 annual supply curves (Figure 1) grouped by:

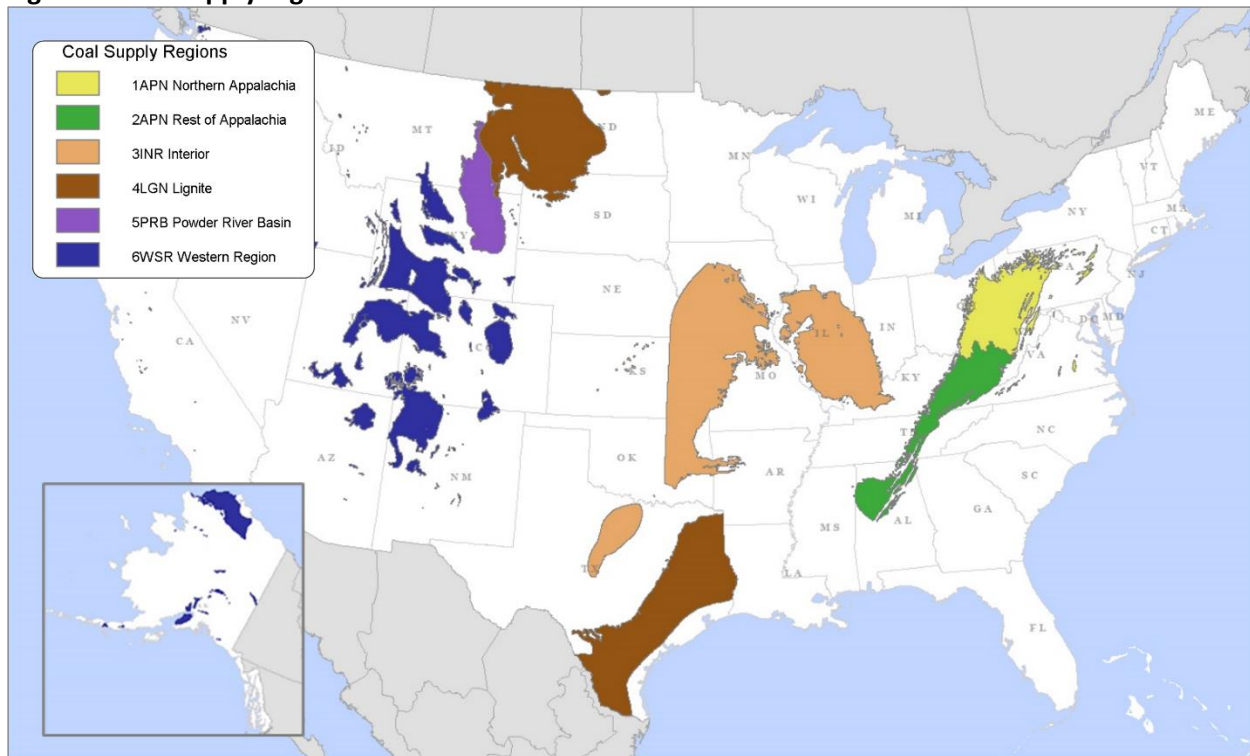
- 6 geographic regions
- 5 coal classification types (representing coal type, thermal grade, and end use)
- Two mining techniques (underground or surface)

EIA derived the coal supply curves by econometric formulation of annual coal production that relates the price level of coal supply to independent variables driving production cost. Changes to cost may shift the curves up or down, but changes to productive capacity may shift the curves out or back. Other factors help determine the shape and elasticity of the curves, such as:

- Historical average capacity utilization for each curve
- Projected available mining capacity for each curve
- Labor productivity for each curve
- Capital cost of mining equipment (nationally)
- Cost of variable factor inputs such as miner wages, electricity, and petroleum fuels (regionally and by mining technique)
- Other mining costs

Historical production capacity utilization in the base year was about 80% for metallurgical coal regions and 68% for steam coal regions. The modeling mechanism allows additional production capacity to be increased by 3% if capacity utilization rises above 88%. Likewise, if capacity utilization of a supply curve falls below 50%, mining capacity in that region will be reduced. This capability represents coal mines opening, closing, expanding, or reducing operations. The amount of capacity the module can add or retire in a given year depends on the supply curve, but for most curves, utilization rates below 50% in a year will reduce capacity by 5% in the following year.

Regional coal mine wages used to construct labor cost are exogenous inputs based on state-level data compiled by the U.S. Department of Labor. The annual wage for U.S. coal miners averaged \$101,950 in 2022.¹ Our *Annual Energy Outlook 2025* (AEO2025) assumes miner wages remain flat in real terms (that is, increase at the general rate of inflation) starting at the 2022 wage level.

Figure 1. Coal supply regions

Data source: U.S. Energy Information Administration

Note: regions are aggregations of USGS coal basin geological definitions.

Other mining costs are represented in the curves by producer price indexes for things like construction equipment, mining machinery, iron and steel products, and explosives. Like wages and productivity, other mining costs are used as dependent variables in the regression that forms the supply curves. We build two separate indexes, one for underground mines and another for surface mines.² The current assumption is that these other mining costs remain constant at 2022 levels.

Each of the 14 coal supply curves have different rates of labor productivity (Table 1). In 2023, model estimated labor productivity averaged 5.7 tons per miner-hour in the United States. EIA compiles data from individual coal mines and preparation plants for historical years. Labor productivity base year values use the quarterly and annual data from the U.S. Department of Labor's Mine Safety and Health Administration (Form 7000-2, *Quarterly Mine Employment and Coal Production Report*) and our Form EIA-7A, *Annual Survey of Coal Production and Preparation*. The module has the capability to change productivity over time, but in AEO2025 the productivity is set constant at the base year values.

Historically, coal mining labor productivity has improved in some regions, while declining in other regions. Driven by the decline in coal use in electricity generation, coal production capacity has been reduced as the mining sector has become smaller from mines closing. Given these trends, EIA does not assume mine productivity improvement in any of the 14 coal regions.

Table 1. Coal mining productivity by supply curve

No.	Supply region	Sulfur grades	Mine type	Coal type	Sulfur grades	2023 Production (million tons)	Productivity (tons per miner hour)	Mine labor hours (million)
1	Northern Appalachia	All	Surface	Bituminous	All	7.5	2.0	3.7
2	Northern Appalachia	All	Underground	Bituminous	All	75.4	4.7	16.1
3	Northern Appalachia	All	Surface	Waste Coal	All	8.1	2.8	2.9
4	Northern Appalachia	All	Underground	Premium	All	18.5	4.7	4.0
5	Rest of Appalachia	All	Surface	Bituminous	All	10.1	2.1	4.7
6	Rest of Appalachia	All	Underground	Bituminous	All	2.9	1.7	1.7
7	Rest of Appalachia	All	Underground	Premium	All	47.9	1.7	28.1
8	Interior	All	Underground	Bituminous	All	49.2	5.6	8.8
9	Interior	All	Surface	Bituminous	All	15.4	4.9	3.2
10	All Lignite	All	Surface	Lignite	All	29.8	9.9	3.0
11	Powder River Basin	All	Surface	Subbituminous	All	215.2	28.0	7.7
12	Western Region	All	Underground	Bituminous	All	8.0	5.1	1.6
13	Western Region	All	Surface	Subbituminous	All	11.6	6.2	1.9
14	Western Region	All	Surface	Bituminous	All	4.3	7.8	0.5
United States total		All	All	All	All	503.9	5.7	87.8

Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2025*, National Energy Modeling System, run ref2025.d032025a

Coal distribution

The CMM's Domestic Coal Distribution Submodule determines the least-cost solution for coal delivered to each demand sector using a linear programming algorithm. Delivered cost include the cost of producing coal (mine price) plus the cost of transporting coal between 14 supply regions and 16 demand regions with 49 demand subsectors (Figure 1 and Figure 2).

The Industrial Demand Module projects demand for industrial steam coal and coking coal; the Commercial Demand Module projects commercial and institutional coal demand. The current version of the NEMS refining model (the Liquid Fuels Market Module) has disabled the ability to create synthetic crude oil or distilled petroleum from coal (commonly called coal-to-liquids, or CTL); therefore, starting with AEO2025, CTL processes are no longer a demand sector for the CMM.

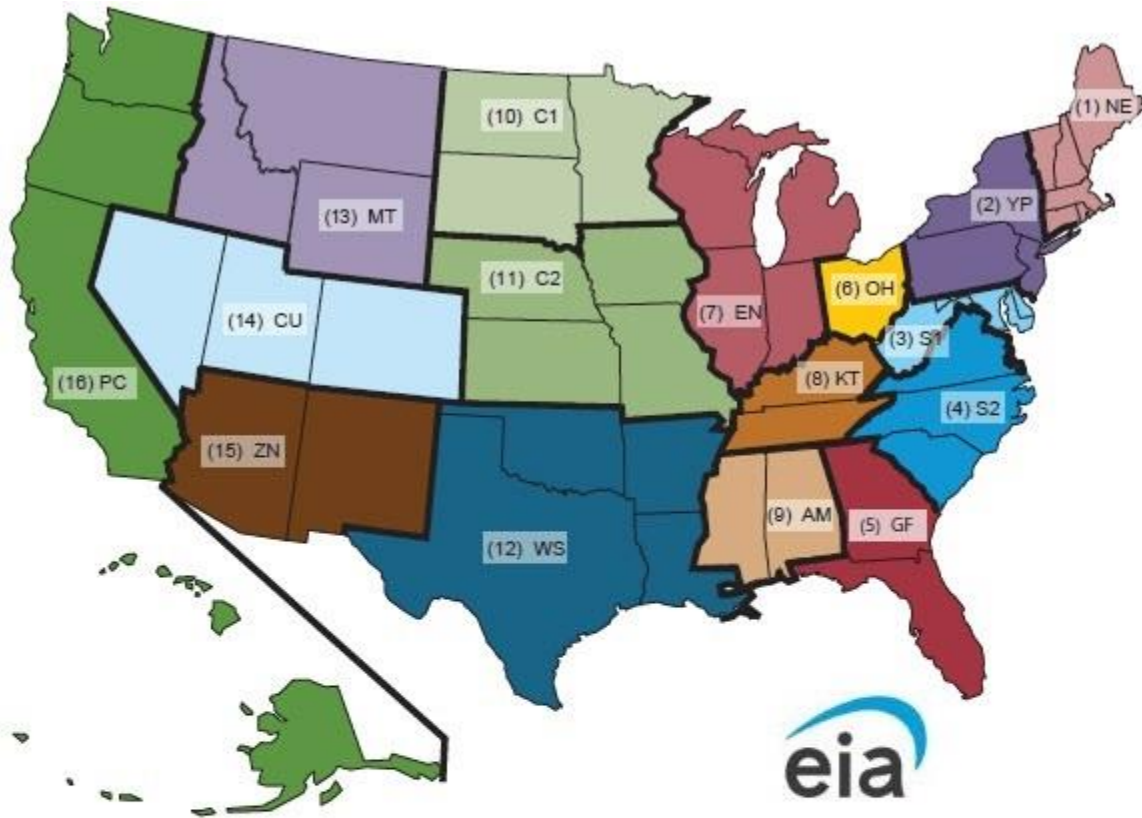
The AEO2025 Reference case assumes rulemaking impacting coal plants from the U.S. Environmental Protection Agency's (EPA) recently finalized Section 111 of the Clean Air Act that regulates CO₂ emissions from existing coal, oil, and natural gas-fired steam generating units and new natural gas-fired combustion turbines. Under the ruling, existing steam generation using coal must retire, convert to burning natural gas, or install carbon capture and storage technology by 2032. The EPA 111 rule drives a significant decline in coal demand in the projection after 2032.

The United States is an exporter of metallurgical and steam coal. We project coal exports and imports in the International Coal Distribution Submodule of the CMM based on:

- Export levels for U.S. coal based on metallurgical and steam coal trade from prior modeling using EIA's World Energy Projection System (WEPS)
- Price and availability of coal supply outside the United States
- Endogenously determined U.S. demand for coal imports
- Exogenously determined world (non-U.S.) coal import demands

We determine transportation rates between coal supply and demand regions by applying an annual projected national transportation price index to a two-tier rate structure. The first tier represents the historical average transportation rate estimated for a base year using our recent survey data. The second tier captures costs associated with changing patterns of coal demand for electricity generation. We updated our approach to coal transportation rate escalation several years ago based on our assessment of the current methodology and independent contractor recommendations.³

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

Data source: U.S. Energy Information Administration

Coal transportation

We calculate base-year domestic coal transportation rates as the average transportation costs for each supply origin-to-demand destination pair (or path), but we don't differentiate by transportation mode (rail, truck, barge, and conveyor). We compute these rates (by demand sector and for exported coal) as the difference between the average delivered price for a coal demand region and either the reported commodity price or the average minemouth price at each available coal supply curve. We define these rates by region, coal rank, and mine type. We derive delivered prices from these sources:

- Survey Form EIA-3, *Quarterly Survey of Industrial, Commercial & Institutional Coal Users*
- Survey Form EIA-923, *Power Plant Operations Report*
- The U.S. Census Bureau, *Monthly Report EM-545*

We derive minemouth prices from survey Form EIA-7A, *Annual Survey of Coal Production and Preparation*. We updated the base-year coal transportation rates in the CMM for AEO2025 based on data from 2020 to 2022 for paths that have been active in recent years. As a result of the transportation rate update, some paths we used historically are now inactive because regional coal demand has disappeared, coal mines have shuttered, or coal trade along the path has become uneconomical.

For the electricity sector, we applied a two-tier transportation rate structure to those regions that, 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.

The CMM adjusts the base-year coal transportation rates, both first and second tier, over time by applying an annual projected index for the national coal transportation rate. The index measures the change in average transportation rates for coal shipments on a tonnage basis by applying a [rail cost adjustment factor](#) (RCAF) approach as used by the American Association of Railroads in quarterly filings to the Surface Transportation Board (STB). The STB's All-Inclusive Index (STB_A-II) is used in the module to adjust railroad productivity. Table 2 shows the coal transportation rate escalation cumulative multipliers in selected years for each of the AEO2025 side cases.

Table 2. Coal transportation rate multipliers

constant dollar index, 2023=1.0000

Case	2023	2024	2025	2030	2035	2040	2045	2050
Reference	1.0000	1.0174	1.0796	1.0672	1.0250	1.0382	1.0439	1.0604
Low Oil Price	1.0000	1.0174	1.0559	1.0319	0.9856	0.9929	0.9896	1.0077
High Oil Price	1.0000	1.0174	1.1566	1.1091	1.0498	1.0757	1.0995	1.1259
Low Economic Growth	1.0000	1.0436	1.1203	1.0826	1.0343	1.0264	1.0291	1.0325
High Economic Growth	1.0000	1.0070	1.0596	1.0485	1.0101	1.0281	1.0383	1.0570
Low Oil & Gas Supply	1.0000	1.0174	1.1254	1.1186	1.0793	1.0569	1.0398	1.0650
High Oil & Gas Supply	1.0000	1.0174	1.0908	1.0438	0.9895	1.0144	1.0373	1.0556
Low Zero-Carbon Technology Cost	1.0000	1.0174	1.0795	1.0674	1.0246	1.0461	1.0594	1.0799
High Zero-Carbon Technology Cost	1.0000	1.0174	1.0796	1.0671	1.0248	1.0347	1.0413	1.0527
Alternative Electricity	1.0000	1.0174	1.0795	1.0672	1.0412	1.0356	1.0441	1.0644
Alternative Transportation	1.0000	1.0174	1.0795	1.0693	1.0308	1.0382	1.0437	1.0590

Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2025*, National Energy Modeling System runs ref2025.d032025a, lowprice.d032125a, highprice.d0302525a, lm.d032425b, hm.d032025a, lowogs.d032625c, highogs.d032425b, lowztc.d032425a, highztc.d032125b, noaa111.d032525c, alttrnp.d032125a

The CMM applies relevant price or interest rate indexes available within the NEMS modeling framework to each RCAF cost share included in the STB_A-II for 2020. The CMM normalizes the NEMS indexes used in the RCAF approach to the year corresponding to the latest shares in the STB_A-II. Under this approach, the CMM applies the 2021 shares to the rate of change from 2020 to 2021 of the corresponding indexes from NEMS to create the weighted-average escalation factor for 2021. The CMM then adjusts the RCAF share weights to reflect their contribution to the escalation factor in 2021 and uses these weights to create the escalation factor for 2022, and so on for each projection year. Table 3 shows the individual cost components, the STB_A-II shares as of 2022, and which NEMS indexes are used to project each cost component. The CMM will then adjust these escalation factors to account for railroad productivity improvements being shared with coal shippers.

Table 3. Rail cost adjustment factor (RCAF) shares and escalator basis

RCAF variable	2022 share	AAR short-term escalator basis	NEMS macroeconomic indexes and prices
Labor	29.4%	Sector analysis of subcomponents for rail sector	Employment cost index. Private wages and salaries adjusted to remove inflation and convert base year (2021=1.00)
Fuel	20.4%	Ultra-low sulfur diesel fuel referenced, but otherwise based on a survey of rail purchasers and petroleum experts	Transportation sector diesel fuel price in 1987 dollars per million British thermal units indexed to base year (2021=1.00)
Materials and supplies	4.7%	References change in prices for metal products and miscellaneous products	Index for railroad materials and supplies based on producer price index of metals and metal products (2021=1.00)
Equipment rentals	4.4%	Producer price index for industrial commodities excluding the cost of fuel, power, and related products (PPI-LF)	Index for equipment rentals based on producer price index of industrial commodities excluding energy (2021=1.00)
Depreciation	15.2%	Producer price index for railroad equipment (PPI-RE)	Index for depreciation based on railroad equipment from the producer price index of transportation equipment (2021=1.00)
Interest	2.1%	Interest rates for 10- and 30-year U.S. Treasury Bonds are referenced, but the latest historical value based on annual reports from railroads is carried forward	Index for borrowed debt by the railroads based on real AA utility bond rates (2021=1.00)
Other	23.8%	Producer price index for industrial commodities excluding the cost of fuel, power, and related products (PPI-LF)	Index for other costs based on producer price index of industrial commodities excluding energy (2021=1.00)

Data source: Association of American Railroads (AAR), [Rail Cost Indexes](#), RCAF Quarterly Filings & Decisions, [STB RCAF 2023Q4 Decision 09-08-2023](#), Docket No. EP 290 (Sub-No. 5) (2023-4); U.S. Energy Information Administration, National Energy Modeling System (NEMS)

We assume that railroad productivity will improve by 1.4% per year, but the shipping rates the railroads charge to their customers will not always reflect these improvements. We base this assumption on the independent contractor analysis described in our assessment of coal transportation rate methodology. If total U.S. annual coal production on a three-year moving average basis is declining, we assume railroad companies share a portion of the rail productivity improvements with their customers to help maintain coal's competitiveness. If coal production decreases by more than 5.0% from one year to the next, we assume rail companies share half of their productivity improvement, or 0.7%, with rail shippers, which is applied to the computed escalation factor using the RCAF methodology. For example, if we project the RCAF to increase by 1.0% from one model year to the next, but coal production is set to decline by more than 5.0%, coal transportation rates would increase by only 0.3% overall. The extent to which shippers share in rail productivity improvements when coal production declines by less than 5.0% decreases to zero exponentially from 5.0% as the decline in coal production approaches zero. We do not assume that railroads share rail productivity improvements if coal production is either flat or increasing from one year to the next.

Coal contracts in the CMM represent the minimum demand for a specific electricity coal that must be met by a unique coal supply source before the CMM considers any alternative supply sources. We estimate base-year (2022) coal contracts between coal producers and electricity generators based on receipts data reported by generators on the Form EIA-923, *Power Plant Operations Report*. We categorize coal contracts by supply region, coal type, demand region, and whether a unit has flue gas desulfurization equipment. We reduce coal contract quantities over time, based on:

- Contract duration data from information reported on Form EIA-923
- Historical patterns of coal use
- Information obtained from various coal and electric power industry publications and reports

Coal imports and exports

Before AEO2022, we modeled coal imports and exports as part of the CMM's linear program that projects annual 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 coal-importing regions for two coal types (steam and metallurgical), including 5 U.S. export regions and 4 U.S. import regions. After we adopted a new module called the [International Coal Market Module \(ICMM\)](#) in IEO2021, international coal production, coal trade, and coal prices for coal produced throughout the world are now exclusively solved for in the ICMM based on international coal demands from our WEPS modules. The CMM matrix of 17 exporting and 14 importing regions for international coal transport (while still active) is now constrained so that U.S. exports of coal in the AEO2025 Reference case (and all side cases) will match coal exports in prior WEPS modeling in million short tons after 2025 and will match exports in the [Short-Term Energy Outlook](#) release within a tolerance of 2% before 2026. Because the CMM no longer determines our view on international coal trade, the inputs for imported coal demand by import region, the supply cost for exported coal by export region, and the ocean transportation costs of moving coal are no longer updated in this module. In addition, we no longer report the output tables for world coal flows by steam coal, metallurgical coal, and total coal flows by importing region and exporting countries as part of the AEO. These projections are available as part of IEO publications.

Coal quality

For each AEO cycle, we calibrate the base-year coal production to survey Form EIA-7A, *Annual Survey of Coal Production and Preparation*. In addition, to reflect the coal quality of each modeled coal source, we calculate the average values for:

- Heat content (million British thermal units [MMBtu] per ton)
- Sulfur content (pounds per MMBtu)
- Mercury content (pounds per trillion British thermal units)
- CO₂ emissions, when the coal is burned (pounds per MMBtu)

We use 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) to calculate these average values. Coal quality for the export sector is based on data collected on Form EIA-7A for domestic production and matches export shipments collected by the U.S. Census Bureau's *Monthly Report EM-545*. Mercury content data for coal by supply region and coal type, in units of pounds of mercury per trillion British thermal units, are derived from shipment-level data reported by electricity generators to EPA in its 1999 *Information Collection Request*. CO₂ emission factors for each coal type, based on data published by EPA, are shown in Table 4 in pounds of CO₂ emitted per million British thermal units.⁴

Table 4. Production, heat content, sulfur, mercury, and CO₂ emission factors by coal region, rank, and mine type

Coal supply No	region	States	Coal rank	Mine type	2022 production (million short tons)	2022 heat content (million British thermal units per short ton)	2022 sulfur content (pounds per million British thermal units)	Mercury content (pounds per trillion British thermal units)	CO ₂ (pounds per million British thermal units)
1	Northern Appalachia	Pennsylvania, Ohio, Maryland, and West Virginia (North)	Bituminous	Surface	6.3	22.1	2.4	32.7	206.5
2	Northern Appalachia	Pennsylvania, Ohio, Maryland, and West Virginia (North)	Bituminous	Deep	69.2	25.6	2.2	13.2	206.5
3	Northern Appalachia	Pennsylvania, Ohio, Maryland, and West Virginia (North)	Waste coal (gob and culm)	Surface	8.9	10.8	5.2	53.4	206.5
4	Northern Appalachia	Pennsylvania, Ohio, Maryland, and West Virginia (North)	Premium	Deep	15.2	28.7	0.6	N/A	206.5
5	Rest of Appalachia	Kentucky (East), West Virginia (South), Virginia, Alabama, and Tennessee	Bituminous	Surface	16.5	24.8	0.8	7.0	204.6
6	Rest of Appalachia	Kentucky (East), West Virginia (South), Virginia, Alabama, and Tennessee	Bituminous	Deep	6.6	24.5	0.6	6.7	204.6
7	Rest of Appalachia	Kentucky (East), West Virginia (South), Virginia, Alabama, and Tennessee	Premium	Deep	47.6	28.7	0.4	N/A	204.6
8	Interior	Illinois, Indiana, Kentucky (West), and Mississippi	Bituminous	Deep	66.4	23.2	2.4	7.8	203.8
9	Interior	Illinois, Indiana, Kentucky (West), and Mississippi	Bituminous	Surface	11.2	22.3	2.6	9.3	203.8
10	Lignite	Texas, North Dakota, Montana, Mississippi, and Louisiana	Lignite	Surface	47.5	13.6	1.3	10.9	215.0
11	Powder River Basin (PRB)	Wyoming and Montana	Subbituminous	Surface	237.7	17.4	0.3	7.4	214.3
12	Western Region	Wyoming (non-PRB), Colorado, Utah, New Mexico, Arizona, and Alaska	Bituminous	Deep	27.7	22.6	0.4	3.9	214.5
13	Western Region	Wyoming (non-PRB), Colorado, Utah, New Mexico, Arizona, and Alaska	Subbituminous	Surface	10.7	18.6	0.6	6.2	213.9
14	Western Region	Wyoming (non-PRB), Colorado, Utah, New Mexico, Arizona, and Alaska	Bituminous	Surface	4.1	19.1	0.4	27.5	214.5

Data source: 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

Note: N/A=not available

Legislation and regulations

We base AEO2025, to the extent possible within the NEMS model framework, on current laws and regulations in effect as of December 1, 2024. The Electricity Market Module (EMM) implements nearly all of the legislation and regulations that apply to coal-fired electric generating units; however, we use the CMM to model certain aspects of the emissions limits in the Clean Air Act Amendments of 1990 (CAAA90) in certain instances. The following are two examples.

Cross-State Air Pollution Rule

The CMM accounts for the Cross-State Air Pollution Rule (CSAPR),⁵ finalized in 2015. On March 15, 2021, EPA finalized an update to the CSAPR, which required power plants in 12 states to revise their emissions budget for nitrogen oxides from 2022 to 2024. More detail on CSAPR is available in the EMM assumptions document.

The CMM sets regional limits (constraints) throughout the projection period for sulfur dioxide based on an annual allowance set by EPA under CSAPR. The sulfur content for U.S. coal produced in 2022 is displayed in Table 4 along with heat content, mercury content, and average CO₂ emissions.

Mercury and Air Toxics Standards

The CMM considers the Mercury and Air Toxics Standards (MATS), finalized in December 2011.

Even though retrofit decisions in the EMM are the primary means of compliance for MATS, a detailed description of how MATS was implemented in NEMS can be found in the EMM Assumptions document. The CMM also includes transportation cost adders for removing mercury using activated carbon injection.

A full discussion of the legislation and regulations affecting the use of coal in power generation and industrial applications such as making coal coke appears in the *Summary of Legislation and Regulations* document located on our [Assumptions website](#).

Notes and Sources

¹ U.S. Department of Labor, Bureau of Labor Statistics, Quarterly Census of Employment and Wages, NAICS 2121. Coal mining for all states and U.S. supply region as well as U.S. average weighted by production and labor hours from Form EIA-7A, [Annual Survey of Coal Production and Preparation](#).

² U.S. Department of Labor, Bureau of Labor Statistics, Series: Producer Price Index by Industry: Mining Machinery and Equipment Manufacturing (PCU333131333131) and Producer Price Index by Industry: Construction Machinery Manufacturing (PCU333120333120).

³ U.S. Energy Information Administration, [Improving the Method for Coal Transportation Rate Escalation in the NEMS Coal Market Module](#) (Washington, DC, August 2020).

⁴ 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, Table A-37 (Washington, DC, April 2011).

⁵ U.S. Environmental Protection Agency, [“Overview of the Cross-State Air Pollution Rule”](#) (Washington, DC, September 7, 2016).