Assumptions to the Annual Energy Outlook 2023: Coal Market Module

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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 quanity 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 41 annual supply curves grouped by:

- 14 geographic regions (Figure 1)
- 10 coal classification types (representing groups based on end use, thermal grade, and average sulfur content)
- Two mining techniques (underground or surface)

We derive 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

The modeling mechanism allows additional production capacity to be added if capacity utilization rises to a predetermined level, typically about 80%. Likewise, if capacity utilization of a supply curve falls, mining capacity can be reduced. This 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 3% in the following year.

Regional coal mine wages 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 $91,927 in 2021.[1] Our *Annual Energy Outlook 2023* (AEO2023) assumes miner wages remain flat in real terms (that is, increase at the general rate of inflation) starting at the 2021 wage level.

We assume producer price indexes representing mine equipment costs remain constant in 2021 dollars over the projection period. We build two equipment indexes for supply curves from multiple U.S. Bureau of Labor Statistics data series. We use a producer price index (PPI) for Mining Machinery and Equipment Manufacturing for underground mining curves and a PPI for Construction Machinery Manufacturing for surface mining supply curves.[2]

Each of the 41 coal supply curves have different regional rates of labor productivity (Table 1). In 2021, labor productivity increased in most regions, and the U.S. average was 6.81 tons per miner-hour compared with 5.78 tons per miner-hour in 2020. Overall, U.S. coal mining labor productivity declines by 2.2% per year between 2021 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 related to 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 to both the U.S. Department of Labor, Mine Safety and Health Administration (Form 7000-2, *Quarterly Mine Employment and Coal Production Report)* and to us (Form EIA-7A, *Annual Survey of Coal Production and Preparation*).

Table 1. Coal mining productivity by region

short tons per miner-hour

Supply region	2020	2021	2022	2030	2040	2050	Average annual growth 2021–2050 (percentage)
Northern Appalachia	3.72	4.37	4.28	4.11	3.91	3.56	-0.7%
Central Appalachia	1.89	1.98	1.91	1.41	1.12	0.90	-2.7%
Southern Appalachia	1.96	2.16	2.12	1.87	1.64	1.46	-1.4%
Eastern Interior	5.38	6.05	6.06	6.09	6.12	6.14	0.1%
Western Interior	3.02	3.93	3.88	3.53	3.33	3.17	-0.7%
Gulf Lignite	7.36	7.78	7.71	7.11	6.61	6.16	-0.8%
Dakota Lignite	11.18	11.94	11.82	10.91	10.14	9.45	-0.8%
Western Montana	12.58	16.53	16.40	15.38	12.40	12.17	-1.1%
Wyoming, Northern Powder River Basin	26.81	31.30	31.11	29.65	27.92	26.29	-0.6%
Wyoming, Southern Powder River Basin	26.29	29.65	29.53	28.60	27.47	26.39	-0.4%
Western Wyoming	5.88	6.27	6.38	4.64	4.35	4.10	-1.5%
Rocky Mountain	4.79	4.76	4.72	3.55	2.99	2.55	-2.1%
Arizona and New Mexico	5.59	5.05	4.49	6.34	2.76	2.52	-2.4%
Alaska and Washington	5.11	5.33	5.35	5.53	5.65	5.76	0.3%
U.S. average	5.78	6.81	6.69	4.87	4.17	3.60	-2.2%

Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2023*, National Energy Modeling System run ref2023.d020623a

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, such as in 2020 during the COVID-19 pandemic. The national average labor productivity rate for coal mining was 6.81 short tons per miner-hour in 2021, which was a 31% increase from the 2012 productivity rate of 5.19 tons per miner-hour, the lowest observed rate in more than 20 years.

We project productivity in some coal fields in the eastern United States 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 2020, an average decline of 3.9% per year. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that producers in Appalachia can achieve from economies of scale. In 2021, Central Appalachian productivity was 1.98 short tons per miner-hour. We project the Central Appalachian region will have the greatest regional decline in productivity per year (2.7%) from 2021 to 2050.

Although declines have been more moderate at the highly productive mines in Wyoming's Southern Powder River Basin (PRB), coal mining productivity in this region still fell by 44% between 2000 and 2020, a 2.8% averge decline per year. For AEO2017 onward, we modified productivity figures for the PRB production areas based on recent private-sector analyses.[3] AEO2023 projects productivity from 2021 to 2050 in Southern PRB to decline at an average 0.4% per year.

The Eastern Interior region has shown the most productivity growth; coal mining productivity grew by 14% between 2000 and 2020, or 0.7% per year. The Eastern Interior region, which has substantial thick, underground minable coal reserves, renewed its coal mining activity in recent years. Several coal companies are operating highly productive longwall mines in this region. We expect productivity growth in the Eastern Interior to average 0.1% per year from 2021 to 2050.

Coal distribution

The CMM's Domestic Coal Distribution Submodule 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. We calculate production and distribution for 14 supply regions and 16 demand regions for 49 demand subsectors (Figure 1 and Figure 2).

The Liquid Fuels Market Module (LFMM) projects coal-to-liquids (CTL) volumes, the Industrial Module projects industrial steam and coking activity, and the Commercial Demand Module projects commercial and institutional coal demand. The Electricity Market Module (EMM) projects coal demand from the electric power sector. We project coal imports and coal exports in the International Coal Distribution Submodule of the CMM based on:

- Availability of coal supply outside the U.S.
- Endogenously determined U.S. import demand
- 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.[4]

Figure 1. Coal supply regions

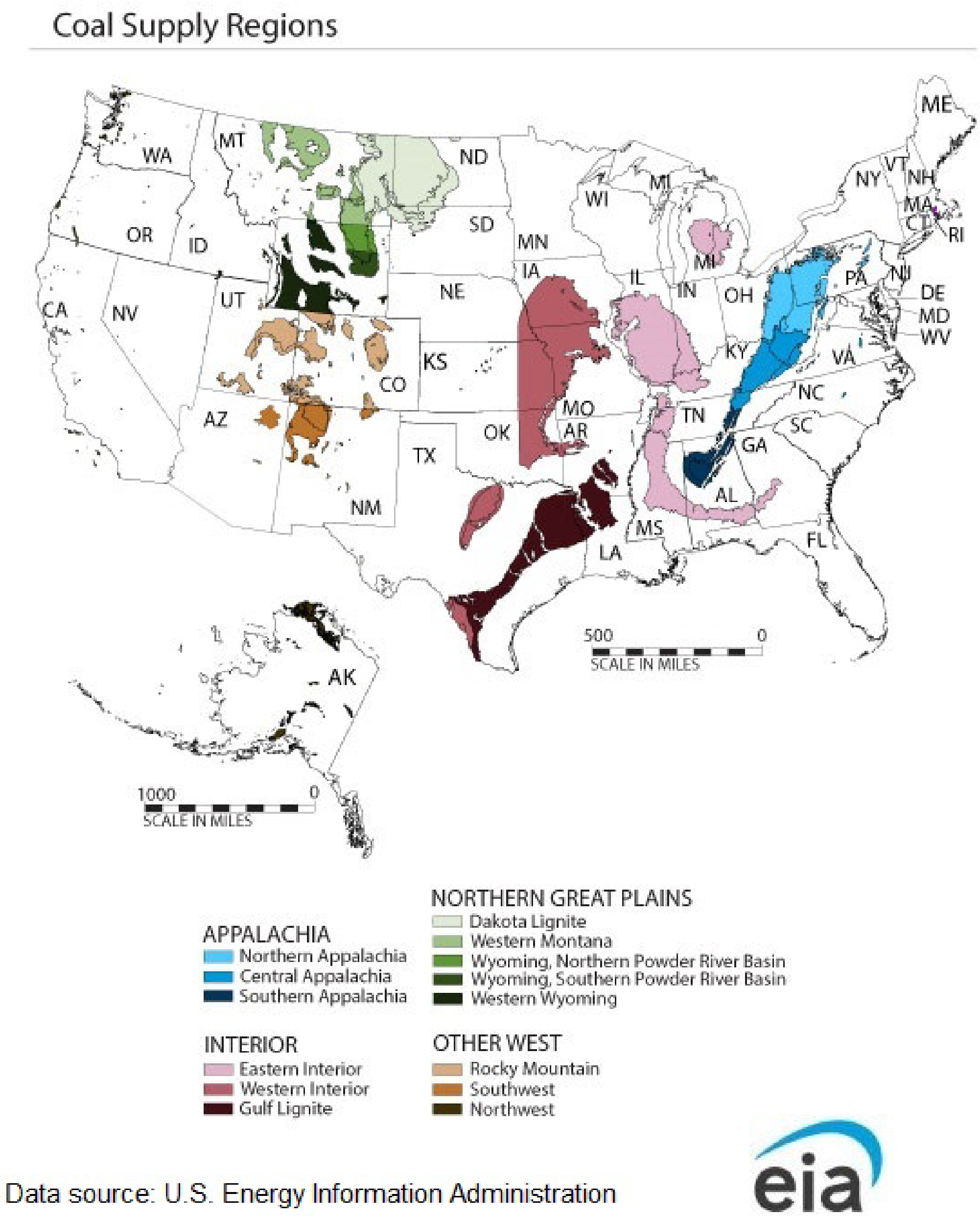
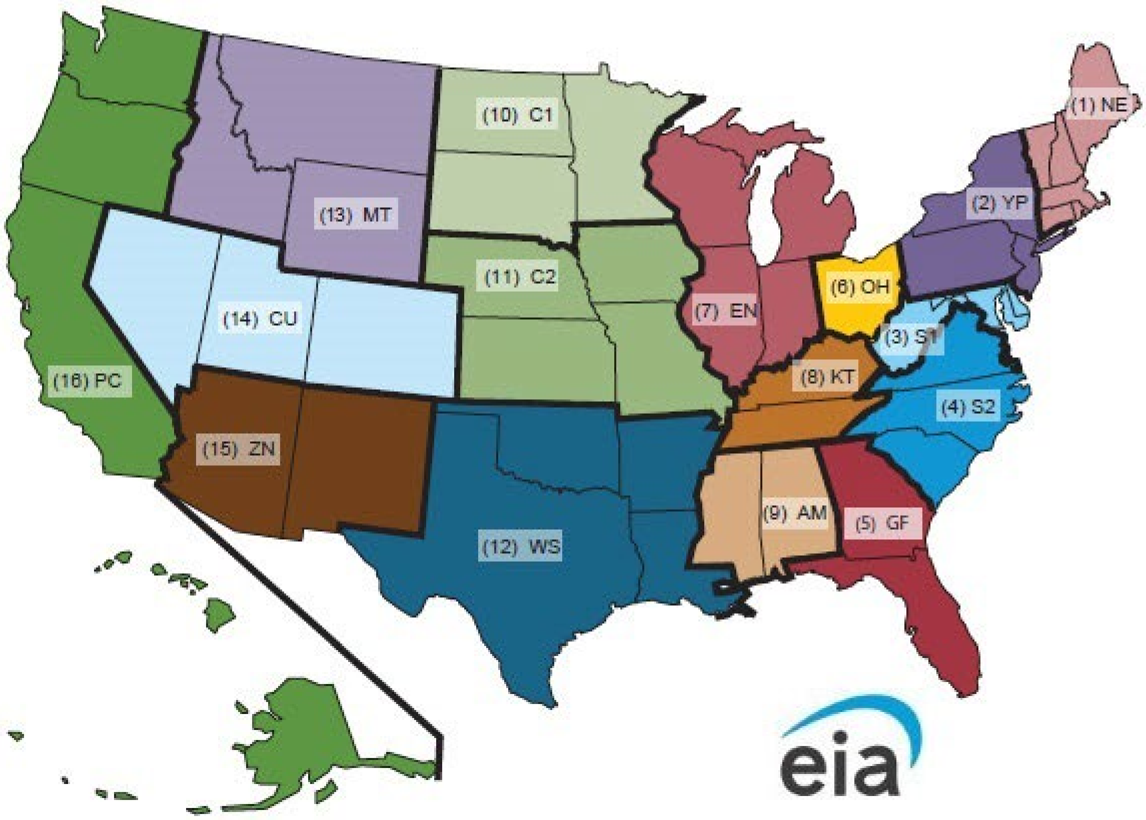


Figure 2. Coal demand regions



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

We calculate base-year domestic coal transportation rates as the average transportation costs for each supply origin-to-demand destination pair, but we don't differentiate by transportation mode (rail, truck, barge, and conveyor). We compute these rates (by sector and for export) as the difference between the average delivered price for a coal demand region and either the reported commodity price or the average minemouth price for each available coal supply curve (Figure 2). We define these rates by region, coal rank, and mine type. We derive delivered prices from three 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 AEO2023 based on data from 2018 to 2020 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. We estimated this cost at $0.10 per million British thermal units (MMBtu) (2000$).[5]

Table 2. Coal transportation rate multipliers

constant dollar index, 2020=1.0000

Case	2021	2022	2025	2030	2035	2040	2045	2050
Reference	1.0000	1.0449	1.0377	1.0262	1.0132	1.0225	1.0245	1.0217
Low Oil Price	1.0000	1.0449	0.9786	0.9992	0.9859	0.9968	1.0072	1.0271
High Oil Price	1.0000	1.0449	1.1079	1.1182	1.1246	1.1508	1.1687	1.1761
Low Economic Growth	1.0000	1.0818	1.0554	1.0407	1.0170	1.0162	1.0125	1.0099
High Economic Growth	1.0000	1.0456	1.0815	1.0602	1.0585	1.0644	1.0702	1.0722
Low Oil & Gas Supply	1.0000	1.0449	1.0804	1.0944	1.0862	1.1081	1.1372	1.1766
High Oil & Gas Supply	1.0000	1.0449	1.0393	1.0320	1.0178	1.0211	1.0136	1.0005
Low Zero-Carbon Technology	1.0000	1.0449	1.0377	1.0245	1.0033	1.0038	0.9948	0.9829
High Zero-Carbon Technology	1.0000	1.0449	1.0376	1.0280	1.0169	1.0260	1.0252	1.0318

Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2023*, National Energy Modeling System runs ref2023.d020623a, lowprice.d020623a, highprice.d020623a, lowmacro.d020623a, highmacro.d020623a, lowogs.d020623a, highogs.d020623a, lowZTC.d020623a, highZTC.d020623a

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, following the cost breakouts in the Surface Transportation Board's (STB) All-Inclusive Index (STB_A-II). The index makes an additional adjustment for railroad productivity improvements. Table 2 shows the coal transportation rate escalation cumulative multipliers in selected years for each of the AEO2023 side cases.

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 2019. 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 2019 shares to the rate of change from 2019 to 2020 of the corresponding indexes from NEMS to create the weighted-average escalation factor for 2020. The CMM then adjusts the RCAF share weights to reflect their contribution to the escalation factor in 2020 and uses these weights to create the escalation factor for 2021, and so on for each projection year. Table 3 shows the individual cost components, the STB_A-II shares as of 2021, 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	2021 share	AAR short-term escalator basis	NEMS macroeconomic indexes and prices
Labor	31.4%	Sector analysis of subcomponents for rail sector	Employment cost index. Private wages and salaries adjusted to remove inflation and convert base year (2019=1.00)
Fuel	14.2%	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 (2019=1.00)
Materials and supplies	4.5%	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 (2019=1.00)
Equipment rentals	4.9%	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 (2019=1.00)
Depreciation	17.5%	Producer price index for railroad equipment (PPI-RE)	Index for depreciation based on railroad equipment from the producer price index of transportation equipment (2019=1.00)
Interest	2.4%	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 (2019=1.00)
Other	25.1%	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 (1982=1.00)

Data source: Association of American Railroads (AAR), Rail Cost Indexes, RCAF Quarterly Filings & Decisions, STB RCAF 2023Q1 Decision 12-20-2022, Docket No. EP 290 (Sub-No. 5) (2023-1); 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 its 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 its 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 (2021) 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 CMM 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

We assume CTL facilities are economical when low-sulfur distillate prices reach high enough levels. We assume these plants are co-production facilities with a generation capacity of 832 megawatts (MW) (295 MW for the grid and 537 MW to support the conversion process) and can produce 48,000 barrels per day of liquid fuels. The assumed technology is similar to an integrated gasification combined cycle: first, the coal feedstock is converted into synthesis gas (syngas), and then the syngas is converted into liquid hydrocarbons using the Fischer-Tropsch process. Of the total amount of coal consumed at each plant, the liquid product retains 40% of the energy input, and the remaining energy is used for the conversion process and producing power sold to the grid. AEO2023 does not model coal-biomass-to-liquids. CTL facilities produce distillate fuel oil (about 72% of their output) as well as the paraffinic naphtha used in plastics production and the blendable naphtha used in motor gasoline (together about 28% of the total by volume).

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 model, 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 World Energy Projection System 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 AEO2023 Reference case (and all side cases) will match the IEO2021 Reference case coal exports in million short tons within a tolerance of 2%. Because this module 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 will 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 will only be 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 (MMBtu per ton)
- Sulfur content (pounds per MMBtu)
- Mercury content (pounds per trillion British thermal units [TBtu])

- Carbon dioxide (CO_2) 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 find 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 the U.S. Environmental Protection Agency (EPA) in the EPA's 1999 *Information Collection Request*. CO_2 emission factors for each coal type, based on data published by EPA, are shown in Table 4 in pounds of CO_2 emitted per million British thermal units.[6]

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

Coal supply region	States	Coal rank and sulfur level	Mine type	2021 production (million short tons)	2021 heat content (million British thermal units per short ton)	2021 sulfur content (pounds per million British thermal units)	Mercury content (pounds per trillion British thermal units)	CO_2 (pounds per million British thermal units)
Northern Appalachia	Pennsylvania, Ohio, Maryland, and West Virginia (North)	Metallurgical	Underground	14.3	28.74	0.56	N/A	204.7
		Mid-sulfur bituminous	All	17.3	24.75	1.14	14.27	204.7
		High-sulfur bituminous	All	57.5	25.28	2.54	13.33	204.7
		Waste coal (gob and culm)	All	7.9	12.53	5.19	27.62	204.7
Central Appalachia	Kentucky (East), West Virginia (South), Virginia, and Tennessee (North)	Metallurgical	Underground	36.9	28.71	0.37	N/A	206.4
		Low-sulfur bituminous	All	8.7	25.83	0.45	5.74	206.4
		Mid-sulfur bituminous	All	9.8	23.94	1.05	8.01	206.4
Southern Appalachia	Alabama and Tennessee (South)	Metallurgical	Underground	10.8	28.70	0.45	N/A	204.7
		Low-sulfur bituminous	All	0.5	26.46	0.77	3.87	204.7
		Mid-sulfur bituminous	All	0.9	24.12	1.29	0.10	204.7
East Interior	Illinois, Indiana, Kentucky (West), and Mississippi	Mid-sulfur bituminous	All	8.0	22.43	1.92	5.01	203.1
		High-sulfur bituminous	All	65.7	22.92	2.48	7.53	203.1
		Mid-sulfur lignite	Surface	3.0	10.41	1.00	25.30	216.5
West Interior	Iowa, Missouri, Kansas, Arkansas, Oklahoma, and Texas	High-sulfur bituminous	Surface	0.1	21.28	2.37	17.42	202.8
Gulf Lignite	Texas and Louisiana	Mid-sulfur lignite	Surface	15.1	13.52	1.32	5.34	212.6
		High-sulfur lignite	Surface	3.7	11.09	3.44	15.28	212.6
Dakota Lignite	North Dakota and Montana	Mid-sulfur lignite	Surface	26.9	13.81	1.23	7.99	219.3
Western Montana	Montana	Low-sulfur bituminous	Underground	7.5	18.15	0.42	3.55	215.5
		Low-sulfur subbituminous	Surface	14.1	18.44	0.36	8.00	215.5
		Mid-sulfur subbituminous	Surface	7.0	17.07	0.64	4.00	215.5
Wyoming, Northern Powder River Basin	Wyoming	Low-sulfur subbituminous	Surface	82.5	16.93	0.35	8.33	214.3
		Mid-sulfur subbituminous	Surface	7.4	16.43	0.71	6.86	214.3

Coal supply region	States	Coal rank and sulfur level	Mine type	2021 production (million short tons)	2021 heat content (million British thermal units per short ton)	2021 sulfur content (pounds per million British thermal units)	Mercury content (pounds per trillion British thermal units)	CO_2 (pounds per million British thermal units)
Wyoming, Southern Powder River Basin	Wyoming	Low-sulfur subbituminous	Surface	137.2	17.73	0.26	6.96	214.3
Wyoming (non-Powder River Basin)	Wyoming	Low-sulfur bituminous	Underground	2.8	19.27	0.63	2.19	214.3
		Low-sulfur bituminous	Surface	4.2	19.51	0.47	1.34	214.3
		Mid-sulfur subbituminous	Surface	1.2	19.22	0.63	4.35	214.3
Rocky Mountain	Colorado and Utah	Metallurgical	Surface	0.0	28.69	0.43	N/A	209.6
		Low-sulfur bituminous	Underground	18.4	22.60	0.44	3.45	209.6
		Low-sulfur subbituminous	Surface	4.3	20.25	0.45	2.04	212.8
Southwest	Arizona and New Mexico	Low-sulfur bituminous	Surface	0.0	21.40	0.48	6.00	207.1
		Mid-sulfur subbituminous	Surface	7.8	18.47	0.96	13.14	209.2
		Mid-sulfur bituminous	Underground	3.0	19.16	0.74	7.18	207.1
Northwest	Washington and Alaska	Low-sulfur subbituminous	Surface	0.8	14.80	0.18	4.86	216.1

Note: N/A=not available

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 CO_2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2011), Table A-37

Legislation and regulations

We base AEO2023 on current laws and regulations in effect as of September 30, 2022. The 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 Clean Air Act Amendments of 1990's (CAAA90) emissions limits in certain instances, including the following:

- The CMM considers the Mercury and Air Toxics Standards (MATS), finalized in December 2011.
- 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.
- The CMM accounts for the Cross-State Air Pollution Rule (CSAPR),[7] finalized in 2015 and updated in 2021, which required 12 states to update their emissions budget for nitrogen oxides.
- The CMM sets regional limits (constraints) throughout the projection period for sulfur dioxide (SO_2) based on annual allowance set by EPA under CSAPR. The sulfur content for U.S. coal produced in 2020 is displayed in Table 4 along with heat content, mercury content, and average CO_2 emissions.

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 *Legislation and Regulations* document. We assume that any coal-fired electricty generating plants that would be built comply with applicable current regulations. We also include a 3-percentage-point adder to the cost-of-capital for coal and natural gas-fired combined-cycle plants to represent observed market behavior of a reluctance to finance or invest in technologies that are at significant risk of being subject to future controls on carbon emissions.

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[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] *Powder River Basin Coal Resource and Cost Study*. Report No. 3155.001. John T. Boyd Company, (Denver, CO, September 2011).

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

[5] Ralph Barbaro and Seth Schwartz, *Review of the Annual Energy Outlook 2002 Reference Case Forecast for PRB Coal*, prepared for the U.S. Energy Information Administration (Arlington, VA: Energy Ventures Analysis, Inc., August 2002).

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