9 Coal

The next three chapters cover the representation and underlying assumptions for fuels in EPA Base Case v.4.10. The current chapter focuses on coal, chapter 10 on natural gas, and chapter 11 on other fuels (fuel oil, biomass, nuclear fuel, and waste fuels) represented in the base case.

This chapter presents four main topics. The first is a description of how the coal market is represented in EPA Base Case v.4.10. This includes a discussion of coal supply and demand regions, coal quality characteristics, and the assignment of coals to power plants.

The next topic is the coal supply curves which were developed for EPA Base Case v.4.10 and the painstaking bottom-up, mine-based approach used to develop curves that would depict the coal choices and associated prices that power plants will face over the modeling time horizon. Included are discussions of the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 84 coal supply curves that are implemented in EPA Base Case v.4.10. Illustrative examples are included of the step-by-step approach employed in developing a supply curves.

The third topic is coal transportation. It includes a description of the transport network, the methodology used to assign costs to the links in the network, and a discussion of the geographic, infrastructure, and regulatory considerations that come into play in developing specific rail, barge and truck transport rates. The last topic covered in this chapter is coal exports, imports, and non-electric sector demand.

The assumptions for the coal supply curves and coal transportation were finalized in September 2008, and were developed through a collaborative process with EPA supported by the following team of coal experts (with key areas of responsibility noted in parenthesis): PA Consulting Group (coal transportation and team coordination), Wood Mackenzie (coal supply curve development), Hellerworx (coal transportation and third party review), and ICF Consulting (representation in IPM). The coal supply curves and transportation matrix implemented in EPA Base Case v.4.10 are included in appendices at the end of this chapter.

9.1 Coal Market Representation in EPA Base Case v.4.10

Coal supply, coal demand, coal quality, and the assignment of specific types of coals to individual coal fired generating units are the four key components of the endogenous coal market modeling framework in EPA Base Case v.4.10. The modeling representation attempts to realistically reflect the actual options available to each existing coal fired power plant while aggregating data sufficiently to keep the model size and solution time within acceptable bounds.

Each coal power plant modeled is assigned to one of 151 coal demand regions. The demand regions are defined to reflect the coal transportation options (rail, barge, truck, conveyer belt) that are available to the plants that they serve. These demand regions are interconnected by a transportation network to at least one of the 31 geographically dispersed coal supply regions. The model's supply-demand region links reflect actual on-the-ground transportation configurations. Every coal supply region can produce and each coal demand region can demand at least one grade of coal. Based on historical and engineering data (as described in Section 9.1.5 below), each coal fired unit is also assigned several coal grades which it may use if that coal type is available within its demand region.

In EPA Base Case v.4.10 the endogenous demand for coal is generated by coal fired power plants interacting with a set of exogenous supply curves (see Appendix 9-4 for coal supply curve data) for each coal grade in each supply region. The curves show the supply of coal (by coal supply region and coal grade) that is available to meet demand at a given price. The supply of and demand for each grade of coal is linked to and affected by the supply of and demand for every other coal grade across supply and demand regions. The transportation network or matrix (see Appendix 9-3 for coal transportation matrix data) also factors into the final determination of

delivered coal prices, given coal demand and supply. IPM derives the equilibrium coal consumption and prices that result when all electric system operating, emission, and other requirements are met and total electric system costs over the modeling time horizon are minimized.

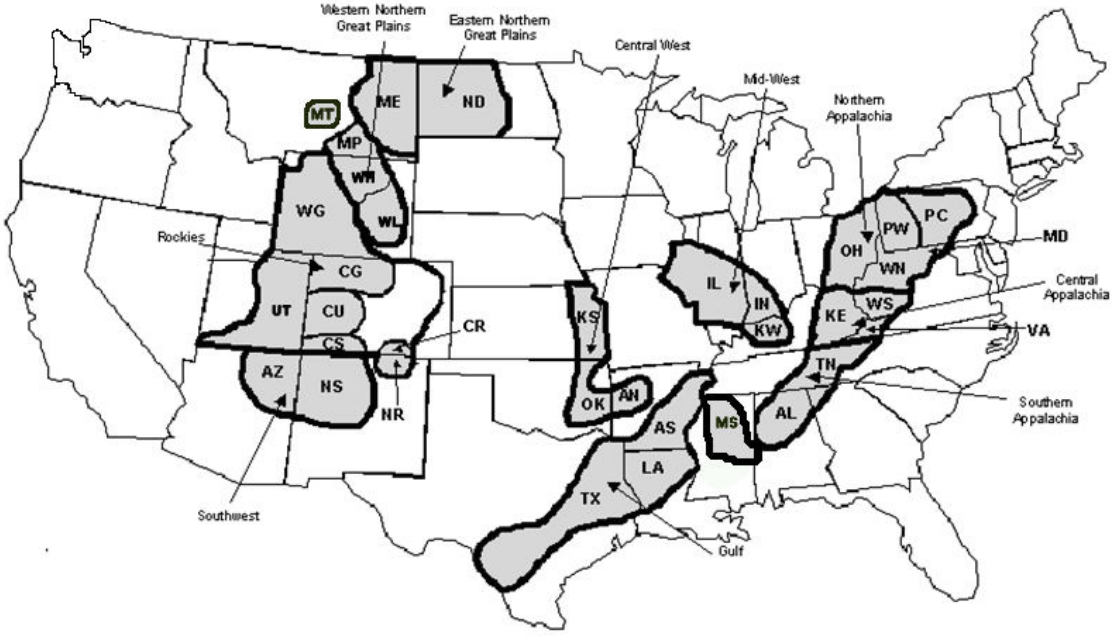
9.1.1 Coal Supply Regions

There are 31 coal supply regions in EPA Base Case v.4.10, each representing geographic aggregations of coal-mining areas that supply one or more coal grades. Coal supply regions may differ from one another in the types and quality of coal they can supply. Table 9-1 lists the coal supply regions included in EPA Base Case v.4.10. Figure 9-1 provides a map showing the location of both the coal supply regions listed in Table 9-1 and the broader supply basins commonly used when referring to U.S. coal reserves.

Table 9-1 Coal Supply Regions in EPA Base Case

Region	State	Supply Region
Central Appalachia	Kentucky, East	KE
Central Appalachia	Tennessee	TN
Central Appalachia	Virginia	VA
Central Appalachia	West Virginia, South	WS
Dakota Lignite	Montana, East	ME
Dakota Lignite	North Dakota	ND
East Interior	Illinois	IL
East Interior	Indiana	IN
East Interior	Kentucky, West	KW
East Interior	Mississippi	MS
Gulf Lignite	Louisiana	LA
Gulf Lignite	Texas	TX
Northern Appalachia	Maryland	MD
Northern Appalachia	Ohio	OH
Northern Appalachia	Pennsylvania, Central	PC
Northern Appalachia	Pennsylvania, West	PW
Northern Appalachia	West Virginia, North	WN
Rocky Mountains	Colorado, Green River	CG
Rocky Mountains	Colorado, Raton	CR
Rocky Mountains	Colorado, Uinta	CU
Rocky Mountains	Utah	UT
Southern Appalachia	Alabama	AL
Southwest	Arizona	AZ
Southwest	New Mexico, San Juan	NS
West Interior	Kansas	KS
West Interior	Oklahoma	OK
Western Montana	Montana, Bull Mountains	MT
Western Montana	Montana, Powder River	MP
Western Wyoming	Wyoming, Green River	WG
Wyoming Northern PRB	Wyoming, Powder River Basin	WH
Wyoming Southern PRB	Wyoming, Powder River Basin	WL

Figure 9-1 Map of the Coal Supply Regions in EPA Base Case v.4.10



9.1.2 Coal Demand Regions

Coal demand regions are designed to reflect coal transportation options available to power plants. Existing coal plants with similar transportation infrastructures (i.e., rail, barge, or truck/conveyor belt), proximity to mine (i.e., mine mouth or not mine mouth), transportation competitiveness levels (i.e., non-competitive, low-cost competitive, or high-cost competitive), and within the same geographic area are grouped into a coal demand region. Table 9-2 below lists the 135 coal demand regions used in EPA Base Case v.4.10 by code and descriptive name.

When IPM is run, it determines the amount and type of new generation capacity to add within each of IPM's 32 model regions. These model regions reflect the administrative, operational, and transmission geographic structure of the electricity grid. Since the coal demand regions do not typically coincide or overlap with the IPM model regions, new coal plants that IPM "builds" in specific model regions must be assigned to a particular coal demand region. The IPM-region-to-coal-demand-region assignments for new coal generating capacity are indicated in column 3 of Table 9-2. Also shown in the last column of Table 9-2 are instances where only one existing power plant is contained in a coal demand region. Forty-seven of the coal demand regions contain only one power plant.

Table 9-2 Coal Demand Regions in EPA Base Case

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
ALR1	Alabama High-Cost Competitive_Not Mine Mouth_Rail	--	
ALR2	Alabama Low-Cost Competitive_Not Mine Mouth_Barge	--	Greene County Plant
ALR3	Alabama Low-Cost Competitive_Not Mine Mouth_Rail	--	E C Gaston Plant
AMM1	New Mexico High-Cost Competitive_Mine Mouth_Rail	--	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
AMM2	Arizona, New Mexico High-Cost Competitive_Not Mine Mouth_Rail	--	Navajo Plant
AMM4	New Mexico Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	San Juan Plant
AMM5	New Mexico Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Raton Plant
AMN1	Arizona High-Cost Competitive_Not Mine Mouth_Rail	--	Apache Station
AMN2	Arizona Low-Cost Competitive_Not Mine Mouth_Rail	--	H Wilson Sundt Generating Station
AMN3	Arizona Non-Competitive_Not Mine Mouth_Rail	AZNM	
CAI1	Virginia High-Cost Competitive_Not Mine Mouth_Rail	--	
CAI2	Kentucky Low-Cost Competitive_Not Mine Mouth_Rail	--	
CAI3	Kentucky Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Tyrone Plant
CAR1	North and South Carolina High-Cost Competitive_Not Mine Mouth_Rail	--	
CAR2	North and South Carolina Low-Cost Competitive_Not Mine Mouth_Rail	--	
CAR3	North and South Carolina Non-Competitive_Not Mine Mouth_Rail	VACA	
CC1	Colorado High-Cost Competitive_Not Mine Mouth_Rail	--	
CC2	Colorado Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
CC3	Colorado Non-Competitive_Not Mine Mouth_Rail	RMPA	
CU1	Utah High-Cost Competitive_Not Mine Mouth_Rail	--	KUCC Plant
CU2	Utah Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	Huntington Plant
CU4	Utah Non-Competitive_Not Mine Mouth_Rail	--	
DAL1	North Dakota High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	Milton R Young Plant
DAL2	Montana, North Dakota Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	
DAL4	North Dakota Non-Competitive_Not Mine Mouth_Rail	--	
EIM1	Iowa, Missouri High-Cost Competitive_Not Mine Mouth_Rail	--	Prairie Creek Plant
EIM2	Iowa Low-Cost Competitive_Not Mine	--	Fair Station Plant

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
	Mouth_Barge		
EIM3	Iowa, Missouri Low-Cost Competitive_Not Mine Mouth_Rail	--	
EIM4	Iowa Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Pella Plant
EIM5	Iowa, Missouri Non-Competitive_Not Mine Mouth_Rail	--	
FL1	Florida High-Cost Competitive_Not Mine Mouth_Rail	FRCC	
FL2	Florida Low-Cost Competitive_Not Mine Mouth_Barge	--	
FL3	Florida Low-Cost Competitive_Not Mine Mouth_Rail	--	
GAR1	Georgia, Mississippi Low-Cost Competitive_Not Mine Mouth_Rail	--	
GAR2	Georgia Non-Competitive_Not Mine Mouth_Rail	SOU	
GFB1	Alabama Low Cost Competitive_Not Mine Mouth_Rail	--	Barry Plant
GFB3	Mississippi Low-Cost Competitive_Not Mine Mouth_Barge	--	Jack Watson Plant
GFB4	Mississippi Non-Competitive_Not Mine Mouth_Rail	--	Victor J Daniel Jr Plant
GFR1	Mississippi, Texas High-Cost Competitive_Not Mine Mouth_Rail	ERCT	
GFR2	Arkansas, Louisiana, Texas Low-Cost Competitive_Not Mine Mouth_Rail	--	
GFR3	Arkansas, Louisiana, Texas Non-Competitive_Not Mine Mouth_Rail	ENTG	
GWAY	Illinois, Mine Mouth	GWAY	
IBB1	Kentucky High-Cost Competitive_Not Mine Mouth_Rail	--	Cane Run Plant
IBB2	Kentucky Low Cost Competitive_Not Mine Mouth_Rail	--	Mill Creek Plant
IBB3	Indiana, Kentucky Low-Cost Competitive_Not Mine Mouth_Barge	--	
IBB4	Illinois, Indiana, Kentucky Low-Cost Competitive_Not Mine Mouth_Rail	--	
III1	Illinois, Indiana High-Cost Competitive_Not Mine Mouth_Rail	--	
III2	Kentucky High-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Green River Plant
III3	Illinois, Indiana, Kentucky Low-Cost Competitive_Not Mine Mouth_Barge	--	
III4	Illinois, Indiana Low-Cost Competitive_Not Mine Mouth_Rail	COMD & RFCO	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
III5	Illinois, Indiana, Kentucky Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
III6	Indiana Non-Competitive_Mine Mouth_Truck/Conveyor Belt	--	Rank E Ratts Plant
III7	Illinois, Indiana, Kentucky Non-Competitive_Not Mine Mouth_Rail	TVAK	
IMB1	Illinois, Iowa, Missouri High-Cost Competitive_Not Mine Mouth_Rail	MRO	
IMB2	Iowa, Missouri Low-Cost Competitive_Not Mine Mouth_Rail	--	
IMB3	Missouri Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
IMB4	Iowa Non-Competitive_Not Mine Mouth_Rail	--	
MA-1	Maryland Low-Cost Competitive_Not Mine Mouth_Rail	--	
MA-2	Maryland Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
MA-3	Maryland Non-Competitive_Not Mine Mouth_Rail	MACS	
MAB1	Maryland Low-Cost Competitive_Not Mine Mouth_Rail	--	
MIB1	Michigan High-Cost Competitive_Not Mine Mouth_Rail	--	
MIB2	Michigan, Wisconsin Low-Cost Competitive_Not Mine Mouth_Barge	--	
MIB3	Michigan, Wisconsin Low-Cost Competitive_Not Mine Mouth_Rail	MECS	
MIB4	Michigan Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Endicott Station
MNR1	Minnesota, South Dakota High-Cost Competitive_Not Mine Mouth_Rail	--	
MNR2	Minnesota Low-Cost Competitive_Not Mine Mouth_Barge	--	Silver Bay Power Plant
MNR3	Minnesota Low-Cost Competitive_Not Mine Mouth_Rail	--	
MNR5	Minnesota, South Dakota Non-Competitive_Not Mine Mouth_Rail	--	
MWR1	Iowa, Kansas, Missouri, Nebraska, Oklahoma High-Cost Competitive_Not Mine Mouth_Rail	SPPN	
MWR2	Kansas, Missouri High-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
MWR3	Kansas, Missouri, Nebraska, Oklahoma Low-Cost Competitive_Not Mine Mouth_Rail	SPPS	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
MWR5	Kansas, Missouri Non-Competitive_Not Mine Mouth_Rail	--	
NAI1	West Virginia High-Cost Competitive_Mine Mouth_Rail	RFCP	
NAI2	West Virginia High-Cost Competitive_Not Mine Mouth_Rail	--	Mt Storm Plant
NAI3	Pennsylvania, West Virginia Low-Cost Competitive_Not Mine Mouth_Barge	--	
NAI4	West Virginia Low-Cost Competitive_Not Mine Mouth_Rail	--	Willow Island Plant
NAI5	West Virginia Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Albright Plant
NAI6	Ohio Non-Competitive_Not Mine Mouth_Rail	--	Muskingum River Plant
NE1	Maine, Massachusetts, New Hampshire, New Jersey High-Cost Competitive_Not Mine Mouth_Rail	--	
NE2	Connecticut, Massachusetts, New Hampshire, New Jersey Low-Cost Competitive_Not Mine Mouth_Barge	--	
NE3	Connecticut, New York Low-Cost Competitive_Not Mine Mouth_Rail	DSNY	
NII1	Indiana High-Cost Competitive_Not Mine Mouth_Rail	--	
NII2	Illinois Low-Cost Competitive_Not Mine Mouth_Barge	--	
NII3	Illinois, Indiana Low-Cost Competitive_Not Mine Mouth_Rail	--	
NNR1	Nevada Non-Competitive_Not Mine Mouth_Rail	--	North Valmy Plant
NOR1	Ohio High-Cost Competitive_Not Mine Mouth_Rail	--	
NOR2	Ohio Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	Conesville Plant
NOR3	Ohio Low-Cost Competitive_Not Mine Mouth_Barge	--	
NOR4	Ohio Low-Cost Competitive_Not Mine Mouth_Rail	--	Hiles Plant
NOR5	Ohio Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
NOR6	Ohio Non-Competitive_Not Mine Mouth_Rail	--	O H Hutchings Plant
NU1	New York High-Cost Competitive_Not Mine Mouth_Rail	UPNY	
NU2	New York Low-Cost Competitive_Not Mine Mouth_Rail	--	AES Westover Plant
ORP1	Ohio, Pennsylvania, West Virginia High-	--	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
	Cost Competitive_Not Mine Mouth_Rail		
ORP2	Ohio, Pennsylvania, West Virginia Low Cost Competitive_Not Mine Mouth_Rail	--	
ORP3	Ohio, West Virginia Low-Cost Competitive_Not Mine Mouth_Barge	--	
ORP4	Ohio, Pennsylvania, West Virginia Low-Cost Competitive_Not Mine Mouth_Rail	--	
PC1	Pennsylvania High-Cost Competitive_Not Mine Mouth_Rail	MACW	
PC2	Pennsylvania High-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Homer City Station
PC3	Pennsylvania Low-Cost Competitive_Not Mine Mouth_Barge	--	
PC4	Pennsylvania Low-Cost Competitive_Not Mine Mouth_Rail	--	P H Glatfelter Plant
PC6	Pennsylvania Non-Competitive_Not Mine Mouth_Rail	--	PPL Montour Plant
PE1	New Jersey, Pennsylvania High-Cost Competitive_Not Mine Mouth_Rail	--	
PE2	Pennsylvania Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Shawville Plant
PE3	Delaware, New Jersey, Pennsylvania Non-Competitive_Not Mine Mouth_Rail	MACE	
PRB1	Wyoming High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	
PRB3	Montana Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Colstrip Plant
PRB4	Wyoming Non-Competitive_Not Mine Mouth_Rail	--	
SNR1	Nevada Non-Competitive_Not Mine Mouth_Rail	SNV	Reid Gardner
TAB1	Alabama High-Cost Competitive_Not Mine Mouth_Rail	--	Charles R Lowman
TAB2	Alabama Low Cost Competitive_Not Mine Mouth_Rail	--	Widows Creek
TAB3	Alabama, Tennessee Low-Cost Competitive_Not Mine Mouth_Barge	--	
TKI1	Tennessee Low-Cost Competitive_Not Mine Mouth_Rail	--	
TKI2	Tennessee Non-Competitive_Not Mine Mouth_Rail	TVA	
TXL1	Mississippi, Texas High-Cost Competitive_Mine Mouth_Rail	--	
TXL2	Texas High-Cost Competitive_Not Mine Mouth_Rail	--	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
TXL3	Texas High-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Twin Oaks Power One Plant
TXL4	Louisiana, Texas Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	
TXL5	Texas Non-Competitive_Not Mine Mouth_Rail	--	Gibbons Creek
VAPW	Virginia, Mine Mouth	VAPW	
VEP1	South Carolina, Virginia High-Cost Competitive_Not Mine Mouth_Rail	--	
VEP2	Virginia Non-Competitive_Not Mine Mouth_Rail	--	
WIR1	Wisconsin High-Cost Competitive_Not Mine Mouth_Rail	--	
WIR2	Wisconsin Low-Cost Competitive_Not Mine Mouth_Rail	WUMS	
WIR4	Wisconsin Non-Competitive_Not Mine Mouth_Rail	--	
WOM1	Michigan Low-Cost Competitive_Not Mine Mouth_Rail	--	Eckert Station
WOM2	Michigan Non-Competitive_Not Mine Mouth_Rail	--	Erickson Station
WON1	California High-Cost Competitive_Not Mine Mouth_Rail	--	
WON2	California Low-Cost Competitive_Not Mine Mouth_Rail	--	ACE Cogeneration Facility
WON3	Montana, Oregon, Washington Non-Competitive_Not Mine Mouth_Rail	PNW	
WYG1	Wyoming High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	NWPE	
WYG2	Wyoming High-Cost Competitive_Not Mine Mouth_Rail	--	Osage Plant
WYG3	Wyoming Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	
WYG4	Wyoming Non-Competitive_Mine Mouth_Rail	--	Jim Bridger

9.1.3 Coal Quality Characteristics

Coal varies by heat content, SO_2 content and mercury content among other characteristics. To capture differences in the sulfur and heat content of coal, a two letter “coal grade” nomenclature is used. The first letter indicates the “coal rank” (bituminous, subbitumionus, or lignite) with their associated heat content ranges (as shown in Table 9-3). The second letter indicates their “sulfur grade,” i.e., the SO_2 ranges associated with a given type of coal. (The sulfur grades and associated SO_2 ranges are shown in Table 9-4.)

Table 9-3 Coal Rank Heat Content Ranges

Coal Type	Heat Content (Btu/lb)	Classification
Bituminous	>10,260 – 13,000	B
Sub-bituminous	> 7,500 – 10,260	S
Lignite	less than 7,500	L

Table 9-4 Coal Grade SO_2 Content Ranges

SO_2 Grade	SO_2 Content Range (lbs/MMBtu)
A	0.00 – 0.80
B	0.81 – 1.20
D	1.21 – 1.66
E	1.67 – 3.34
G	3.35 – 5.00
H	> 5.00

The assumptions in EPA Base Case v.4.10 on the heat, mercury, SO_2, and ash content of coal are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR)[1]. A two-year effort initiated in 1998 and completed in 2000, the ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies, (2) obtaining "accurate information on the amount of mercury contained in the as-fired coal used by each electric utility steam generating unit… with a capacity greater than 25 megawatts electric, as well as accurate information on the total amount of coal burned by each such unit,", and (3) obtaining data by coal sampling and stack testing at selected units to characterize mercury reductions from representative unit configurations. Data regarding the SO_2 and ash content of the coal used was obtained along with mercury content.

The ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content, ash content, and other characteristics of coal burned at coal-fired utility units greater than 25 MW.

9.1.4 Emission Factors

To make this data usable in EPA Base Case v.4.10, the ICR data points were first grouped by IPM coal grades and IPM coal supply regions. Using the grouped ICR data, the average heat, SO_2, mercury, and ash content were calculated for each coal grade/supply region combination. In instances where no data were available for a particular coal grade in a specific supply region, the national average SO_2 and mercury values for the coal grade were used as the region's values. The resulting values are shown in Table 9-5.

[1] Data from the ICR can be found at http://www.epa.gov/ttn/atw/combust/utiltox/mercury.html.

Table 9-5 Coal Quality Characteristics by Supply Region and Coal Grade

Coal Supply Region	Coal Grade	Heat Content (MMBtu/Ton)	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/TBtu)	Ash Content (lbs/MMBtu)	Cluster Number
AL	BB	24.82	1.1	4.2	9.8	2
	BD	24	1.4	7.3	10.8	2
	BE	23.82	2.7	12.6	10.7	2
AZ	BB	24.64	1.1	5.3	7.9	2
CG	BA	21.49	0.7	3.1	7.3	1
	BB	22.01	0.9	4.1	8.4	2
CR	BA	25.5	0.7	3.5	7	1
	BD	22.2	1.4	7	8.3	1
CU	BA	23.8	0.7	2.6	6.3	1
	BB	23.22	0.9	4	7.8	2
	BD	23.21	1.3	3.1	8.1	1
IL	BE	23	2.2	6.5	6.6	2
	BG	23.01	4.6	6.5	8.1	1
	BH	22.19	5.6	5.4	9.1	1
IN	BD	22.62	1.4	3.8	7.4	1
	BE	23.43	2.3	5.2	8	2
	BG	23.37	4.3	7.2	8.2	1
	BH	23.41	6.1	7.1	8.6	1
KE	BA	25.32	0.7	3	6.1	1
	BB	25.79	1	4.8	6.4	2
	BD	25.33	1.4	6	7.4	1
	BE	25.14	2.1	7.9	7.7	2
	BG	24.09	3.8	12	10.2	3
KS	BG	25.32	4.8	4.1	8.5	1
KW	BD	24.23	1.6	5.6	6.2	1
	BE	24.45	2.8	7.1	7.4	2
	BG	23.93	4.5	6.9	8	1
	BH	22.84	5.7	8.2	10.2	1
LA	LE	14.09	2.5	7.3	17.1	2
MD	BB	24.64	1.1	5.3	7.9	2
	BD	26.32	1.6	7.8	9.5	2
	BE	24.85	2.8	15.6	11.7	1
	BG	23.26	3.6	16.6	16.6	3
ME	LD	13.36	1.4	8.6	11.3	1
MP	SA	18.9	0.6	4.2	4	1
	SD	17.23	1.5	4.5	10.1	1
MS	LE	13.19	2.8	12.4	21.5	1
MT	BB	21	1.1	5.3	7.9	2
ND	LD	13.7	1.5	6.4	10.7	1
	LE	13.46	2.3	8.3	12.8	1
NS	BB	26.4	1.1	5.3	7.9	2
	BD	18.1	1.6	5.5	19.6	1

Coal Supply Region	Coal Grade	Heat Content (MMBtu/Ton)	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/TBtu)	Ash Content (lbs/MMBtu)	Cluster Number
	BE	18.1	1.8	8.2	18.8	2
OH	BB	24.68	1.1	5.7	9.8	1
	BD	25.55	1.4	6.4	10.3	1
	BE	25.24	3.1	18.7	7.1	1
	BG	24.34	4	18.5	8	2
	BH	23.92	6.4	13.9	9.1	2
OK	BE	22.15	2.7	25.8	11.3	1
PC	BD	25.06	1.4	21.7	49.3	3
	BE	25.66	2.6	18	9.2	1
	BG	25.33	3.8	21.5	9.6	2
	BH	23.39	6.3	34.7	13.9	3
PW	BD	24.26	1.6	11.2	10	2
	BE	26.22	2.5	8.4	5.4	2
	BG	25.86	3.7	8.6	6.5	1
TN	BB	24.18	1.1	3.8	10.4	2
	BD	23.91	1.3	6.3	10.4	1
	BE	26.75	2.1	8.4	6.5	2
TX	LD	13.06	1.6	12	22.3	2
	LE	13.22	3	14.7	25.6	1
	LG	12.27	3.9	14.9	25.5	1
UT	BA	23.68	0.7	4.4	7.4	2
	BB	23.23	0.9	3.9	8.6	2
	BD	23.05	1.4	4.4	10.5	1
	BE	25.06	2.3	9.2	7.4	2
VA	BA	22.7	0.7	3.5	7	1
	BB	25.97	1	4.6	7	2
	BD	25.76	1.4	5.7	8	1
	BE	26.03	2.1	8.4	8.1	2
WG	BB	21.67	1.1	1.8	5.6	1
	SD	18.5	1.3	4.3	10	1
WH	SA	17.43	0.6	5.6	5.5	2
	SB	17.43	0.9	6.4	6.5	1
WL	SB	17.15	0.9	6.4	6.5	1
WN	BD	25.01	1.5	10.3	9.2	2
	BE	25.67	2.5	10.3	7.9	2
	BG	26.03	4	9.3	6.9	1
	BH	25.15	6.1	8.8	9.6	1
WS	BA	26.2	0.7	3.5	7	1
	BB	24.73	1.1	5.7	9.2	2
	BD	24.64	1.3	8.1	9.3	2
	BE	24.38	1.9	8.8	9.9	2
	BG	25.64	4.7	7.1	6.4	1

Next, a clustering algorithm was used to further aggregate the data in EPA Base Case v.4.10 for model size management purposes. The clustering analysis was performed on the mercury and SO_2 data shown in Table 9-5 using the SAS statistical software package. Clustering analysis places objects into groups or clusters, such that data in a given cluster tend to be similar to each other and dissimilar to data in other clusters. The clustering analysis involved two steps. (In the following write-up BG coal is used to illustrate how the procedure worked.) First, the number of clusters of mercury and SO_2 concentrations for each IPM coal type was determined based on the range in average mercury and SO_2 concentrations across all coal supply regions for a specific coal type. Each coal type used either one or two clusters. The total number of clusters for each coal grade was limited to keep the model size and run time within feasible limits. (Two clusters were used for BG coal.) Second, for each coal grade the clustering procedure was applied to all the regional SO_2 and mercury values shown in Table 9-5 for that coal grade. (In the BG coal example there are 11 such regional SO_2 and mercury values.) Using the SAS cluster procedure, each of the constituent regional values was assigned to a cluster and the cluster average SO_2 and mercury values were recorded. The resulting values are shown in Table 9-6 and Table 9-7. (For BG coal the Cluster #1 average SO_2 and mercury values are 4.36 lb/MMBtu and 7.10 lb/TBtu respectively. The Cluster #2 average SO_2 and mercury values are 3.89 lb/MMBtu and 20.04 lb/TBtu respectively. The Cluster #3 average SO_2 and mercury values are 3.68 lb/MMBtu and 14.31 lb/TBtu respectively.) Although not used in determining the clusters, ash and CO_2 values were calculated for each of the clusters. These values are shown in Table 9-8 and Table 9-9. (The CO_2 values were derived from data in the Energy Information Administration's *Annual Energy Outlook* 2009 (AEO 2009), not from data collected in the ICR.)

IPM input files retain the mapping between different coal grade/supply region combinations and the clusters. The mapping can be seen in the last column of Table 9-5 which shows the cluster number associated with the coal grade/supply region combination indicated in the first and second columns of this table. (For BG coal, the SAS cluster procedure mapped supply regions IL, IN, KS, KW, PW, WN, and WS to Cluster #1, supply regions OH and PC to Cluster #2, and MD and KE to Cluster #3. See Figure 9-2 for an illustration of this mapping.) Table 9-6 to Table 9-9 show the mercury, SO_2, ash, and CO_2 values assigned to coal grades and regions based on this cluster mapping. The values shown in Table 9-6 to Table 9-9 are used in EPA Base Case v.4.10 for calculating emissions.

Table 9-6 SO_2 Emission Factors of Coal Used in EPA Base Case v.4.10

Coal Type by Sulfur Grade	Sulfur Emission Factors (lbs/MMBtu)		
	Cluster #1	Cluster #2	Cluster # 3
Low Sulfur Eastern Bituminous (BA)	0.7	0.67	--
Low Sulfur Western Bituminous (BB)	1.13	1.03	--
Low Medium Sulfur Bituminous (BD)	1.43	1.45	1.42
Medium Sulfur Bituminous (BE)	2.78	2.3	--
High Sulfur Bituminous (BG)	4.36	3.89	3.68
High Sulfur Bituminous (BH)	5.89	6.43	6.29
Low Sulfur Subbituminous (SA)	0.62	0.58	--
Low Sulfur Subbituminous (SB)	0.94	--	--
Low Medium Sulfur Subbituminous (SD)	1.41	--	--
Low Medium Sulfur Lignite (LD)	1.46	1.61	--
Medium Sulfur Lignite (LE)	2.88	2.38	--
High Sulfur Lignite (LG)	3.91	--	--

Table 9-7 Mercury Emission Factors of Coal Used in EPA Base Case v.4.10

Coal Type by Sulfur Grade	Mercury Emission Factors (lbs/TBtu)		
	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Eastern Bituminous (BA)	3.19	4.37	--
Low Sulfur Western Bituminous (BB)	1.82	4.86	--
Low Medium Sulfur Bituminous (BD)	5.38	8.94	21.67
Medium Sulfur Bituminous (BE)	19.53	8.42	--
High Sulfur Bituminous (BG)	7.1	20.04	14.31
High Sulfur Bituminous (BH)	7.38	13.93	34.71
Low Sulfur Subbituminous (SA)	4.24	5.61	--
Low Sulfur Subbituminous (SB)	6.44	--	--
Low Medium Sulfur Subbituminous (SD)	4.43	--	--
Low Medium Sulfur Lignite (LD)	7.51	12	--
Medium Sulfur Lignite (LE)	13.55	7.81	--
High Sulfur Lignite (LG)	14.88	--	--

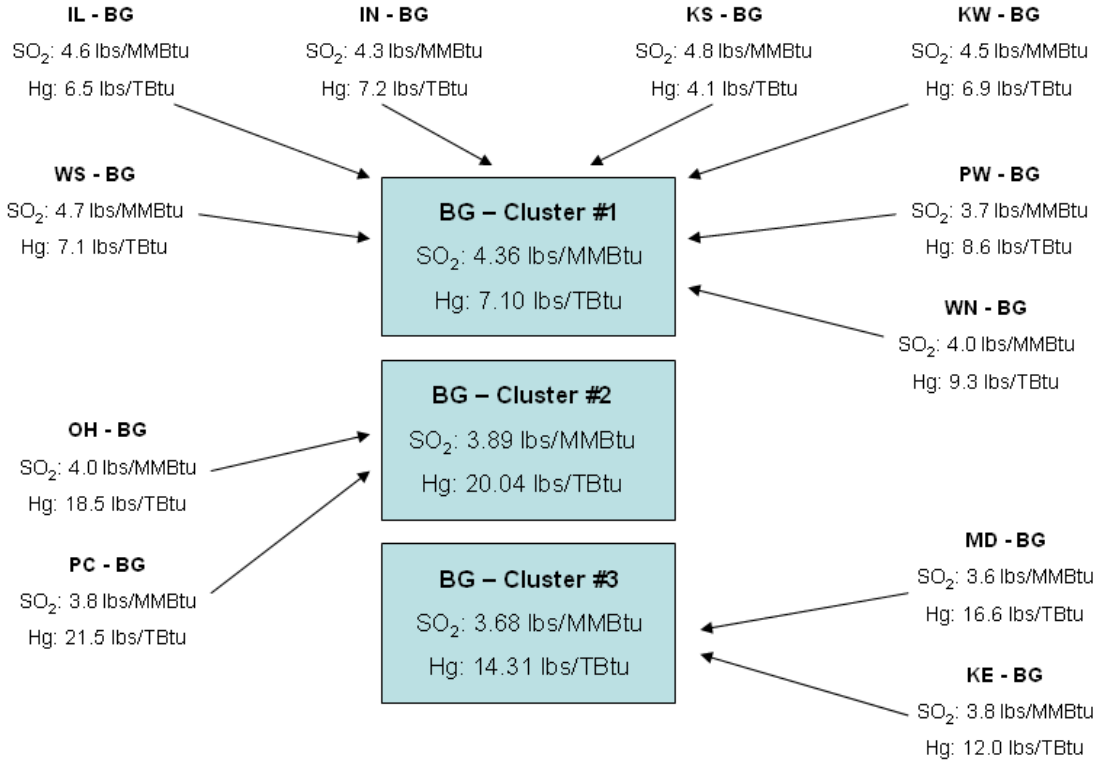
Table 9-8 Ash Emission Factors of Coal Used in EPA Base Case v.4.10

Coal Type by Sulfur Grade	Ash Emission Factors by Coal Sulfur Grades (lbs/MMBtu)		
	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Eastern Bituminous (BA)	6.77	7.39	--
Low Sulfur Western Bituminous (BB)	5.59	8.1	--
Low Medium Sulfur Bituminous (BD)	9.64	9.77	49.31
Medium Sulfur Bituminous (BE)	9.84	8.69	--
High Sulfur Bituminous (BG)	7.51	8.8	13.41
High Sulfur Bituminous (BH)	9.38	9.13	13.89
Low Sulfur Subbituminous (SA)	3.98	5.47	--
Low Sulfur Subbituminous (SB)	6.5	--	--
Low Medium Sulfur Subbituminous (SD)	10.08	--	--
Low Medium Sulfur Lignite (LD)	11.01	22.33	--
Medium Sulfur Lignite (LE)	23.58	15	--
High Sulfur Lignite (LG)	25.51	--	--

Table 9-9 CO_2 Emission Factors of Coal Used in EPA Base Case v.4.10

Coal Type by Sulfur Grade	CO_2 Emission Factors by Coal Sulfur Grades (lbs/MMBtu)		
	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Eastern Bituminous (BA)	205.4	205.4	--
Low Sulfur Western Bituminous (BB)	205.8	205.8	--
Low Medium Sulfur Bituminous (BD)	206.6	206.6	206.6
Medium Sulfur Bituminous (BE)	206.3	206.3	--
High Sulfur Bituminous (BG)	205.2	205.2	205.2
High Sulfur Bituminous (BH)	205.2	205.2	205.2
Low Sulfur Subbituminous (SA)	213.1	213.1	--
Low Sulfur Subbituminous (SB)	212.7	--	--
Low Medium Sulfur Subbituminous (SD)	213.1	--	--
Low Medium Sulfur Lignite (LD)	217	217	--
Medium Sulfur Lignite (LE)	214.8	214.8	--
High Sulfur Lignite (LG)	213.5	--	--

Figure 9-2 Cluster Mapping Example --- BG Coal



9.1.5 Coal Grade Assignments

The grades of coal that may be used by specific generating units were determined by an expert assessment of the ranks of coal that a unit had used in the past, the removal efficiency of the installed FGD, and the SO_2 permit rate of the unit. Examples of the coal grade assignments made for individual plants in EPA Base Case v.4.10 are shown in Table 9-10. Not all of the coal grades

allowed to a plant by the coal grade assignment are necessarily available in the plant's assigned coal demand region (due to transportation limitations). IPM endogenously selects the coal burned by a plant by taking into account both the constraint of the plant's coal grade assignment and the constraint of the coals actually available within a plant's coal demand region.

Table 9-10 Example of Coal Assignments Made in EPA Base Case

Plant Name	Unique ID	SIP SO_2 Limit (lbs/MMBtu)	Scrubber?	Fuels Allowed
Salem Harbor	1626_B_1	1.2	No	BA,BB
Dickerson	1572_B_3	2.8	No	BA,BB,BD,BE
Glen Lyn	3776_B_51	1.75	No	BA,BB,BD
Danskammer Generating Station	2480_B_3	1.1	No	BA,BB
R E Burger	2864_B_5	9.02	No	BA,BB,BD,BE,BG,BH
Moutaineer	6264_B_1	1	Yes	BA,BB,BD,BE,BG,BH, SA,SB,SD
Big Brown	3497_B_1	3	No	LD,LE,SA,SB,SD
Black River Generation	10464_B_E0001	3.8	Yes	BA,BB,BD,BE,BG,BH
E D Edwards	856_B_1	4.71	No	BA,BB,BD,BE,BG,SA, SB,SD
R Gallagher	1008_B_1	4.71	No	BA,BB,BD,BE,BG,SA, SB,SD

9.2 Coal Supply Curves

9.2.1 Nature of Supply Curves Developed for EPA Base Case v.4.10

In keeping with IPM's data-driven bottom-up modeling framework, a bottom-up approach (relying heavily on detailed economic and resource geology data and assessments) was used to prepare the coal supply curves for EPA Base Case v.4.10. Wood Mackenzie was chosen to develop the curves based on their extensive experience in preparing mine-by-mine estimates of cash operating costs for operating mines in the U.S., their access to both public and proprietary data sources, and their active updating of the data both through research and interviews.

In order to establish consistent nomenclature, Wood Mackenzie first mapped its internal list of coal regions and qualities to EPA's 31 coal supply regions (described above in sections 9.1.1) and 12 coal grades (described above in section 9.1.3). The combined code list is shown in Table 9-11 below with the IPM supply regions appearing in the rows and the coal grades in the columns. Wood Mackenzie then created supply curves for each region and coal-grade combination (indicated by the "x" in Table 9-11) for forecast years 2012, 2015, 2020, 2030, and 2040.

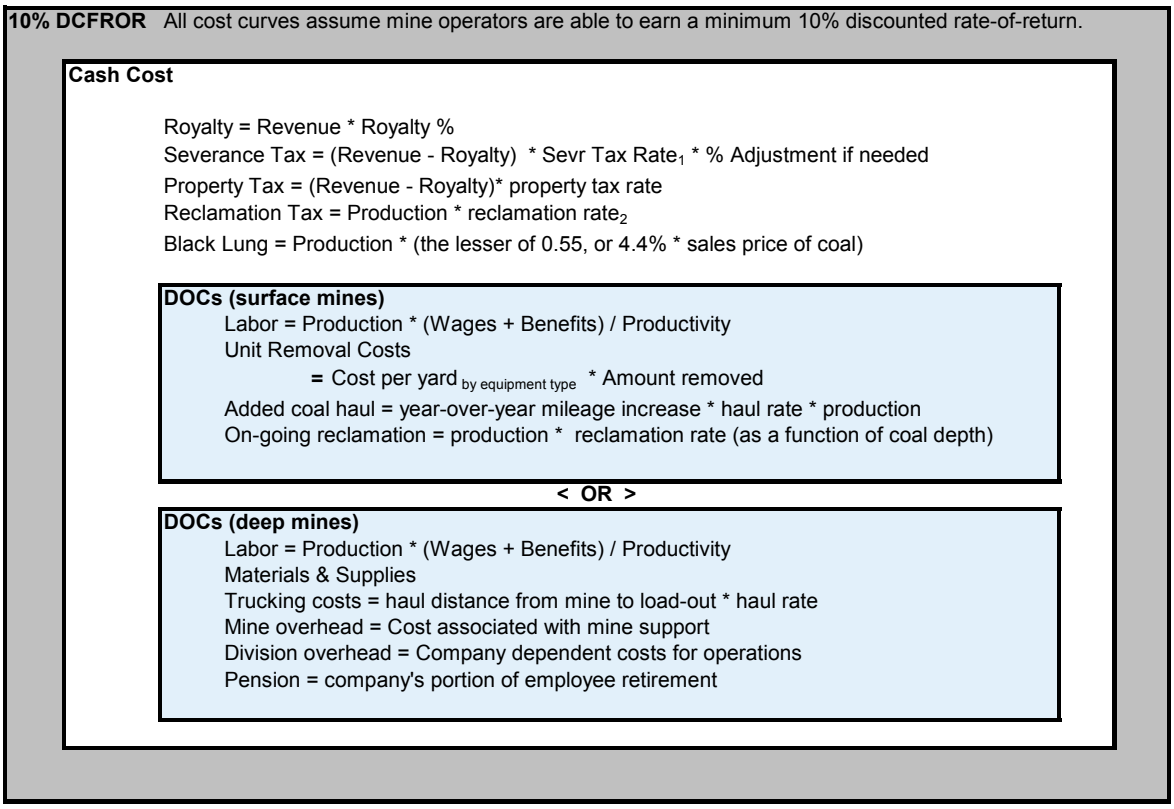
Table 9-11 Basin-Level Groupings Used in Preparing v.4.0 Coal Supply Curves

Coal Supply Regions and Coal Grades in EPA IPM, v.4.0				BITUMINOUS						SUB-BITUMINOUS			LIGNITE			
		Coal Code		1	2	3	4	5	6	7	8	9	10	11	12	13
Geo. Region	Geo. Sub-Region	Region Code		BA	BB	BD	BE	BG	BH	SA	SB	SD	LD	LE	LG	LH
Appalachia	Southern Appalachia	1	AL		X	X	X									
West	Southwest	2	AZ		X											
West	Rocky Mountain	3	CG	X	X											
West	Rocky Mountain	4	CR	X		X										
West	Rocky Mountain	5	CU	X	X	X										
Interior	East Interior (Illinois Basin)	6	IL				X	X	X							
Interior	East Interior (Illinois Basin)	7	IN			X	X	X	X							
Interior	Gulf Lignite	8	LA											X		
Appalachia	Northern Appalachia	9	MD		X	X	X	X								
West	Dakota Lignite	10	ME										X			
Appalachia	Central Appalachia	11	KE	X	X	X	X	X								
Interior	West Interior	12	KS					X								
Interior	East Interior (Illinois Basin)	13	KW			X	X	X	X							
West	Western Montana	14	MP							X		X				
Gulf	Gulf Coast Lignite	15	MS											X		
West	Western Montana	16	MT		X											
West	Dakota Lignite	17	ND										X	X		
West	Southwest	18	NS		X	X	X									
Appalachia	Northern Appalachia	19	OH		X	X	X	X	X							
Interior	West Interior	20	OK				X									
Appalachia	Northern Appalachia	21	PC			X	X	X	X							
Appalachia	Northern Appalachia	22	PW			X	X	X								
Appalachia	Central Appalachia	23	TN		X	X	X									
Gulf	Gulf Coast Lignite	24	TX										X	X	X	X
West	Rocky Mountain	25	UT	X	X	X	X									
Appalachia	Central Appalachia	26	VA	X	X	X	X									
West	Western Wyoming	27	WG		X							X				
West	Wyoming Powder River Basin	28	WH							X	X					
West	Wyoming Powder River Basin	29	WL								X					
Appalachia	Northern Appalachia	30	WN			X	X	X	X							
Appalachia	Central Appalachia	31	WS	X	X	X	X	X								

9.2.2 Procedure Employed in Determining Mining Costs

Wood Mackenzie estimates mine production costs on a mine-by-mine basis utilizing proprietary bottom-up engineering cost models. A mine's cash costs are the sum of its direct operating costs (DOCs), royalty tax, severance tax, property tax, reclamation tax and black lung fees. Using these mine costing models, costs curves are developed by summing the individual and incremental costs that make up mine cash-costs and assuming a built-in 10% discounted rate-of-return. As an illustration of the break-down of costs included in the mine costing models, Figure 9-3 lists the cost components included and calculations performed for a Powder River Basin mine supply curve. Appendix 9-1 contains a more detailed illustration of the procedure used to derive a supply curve from its constituent mine costing models.

Figure 9-3 Cost Calculations Included When Developing Coal Supply Curves (based on a Powder River Basin Mine Supply Curve Example)



General Definitions:

Revenues = Tons coal produced * sale price/ton
Productivity (TPMH) = Tons coal produced / man hours worked in reporting period
Stripping Ratio = Overburden Yard / Coal Production
Production = Amount of coal removed from the mine in a given period

Cash cost: is the sum of a mine's Direct Operating Costs (DOCs), Royalty tax, Severance Tax, Property Tax, Reclamation Tax and Black Lung fees.

[1] Severance Tax Rate is state specific

[2] Reclamation Tax used was 0.15 for Deep Mines & 0.35 for Surface Mines

It is important to note that although the formula for calculating mine costs is consistent across regions, some tax rates and fees vary by state and mine type. In general, there are two mine types: underground (deep) or surface mines. Underground mining is categorized as being either a longwall (LW) or a continuous room-and-pillar mine (CM). Geologic conditions and characteristics of the coal seams determine which method will be used. Surface mines are typically categorized by the type of mining equipment used in their operation such as draglines (DL), or truck & shovels (TS). These distinctions are important because the equipment used by the mine affects productivity measures and ultimately mine costs.

Several methods are employed for cost estimation depending on the availability of information and the diversity of mining operations. When possible, Wood Mackenzie analysts develop detailed lists of mine related costs. Costs such as employee wages & benefits, diesel fuel, spare parts, roof bolts and explosives among a host of others are summed to form a mine's direct operating costs.

Direct costs categories include: mine labor, salaries, material and supplies, and mine overhead. The costs are estimated based on labor productivity and mining methods. Labor productivity is used to calculate mine labor and salaries by applying an average cost per employee hour to the labor productivity figure reported by MSHA or estimated based on comparable mines. For surface mines, material and supply costs are estimated based on the mining method (dragline, truck-shovel and other) and the number of yards of overburden[1] moved by each method. A cost per yard moved is estimated for each mining method and mining region. Where coal is washed, washing costs are based on the type of plant being used and the average washing cost per ton for the mining region. Overhead costs are estimated based on mine size.

Labor costs are estimated based on employment data reported to MSHA. MSHA data provides employment numbers, employee hours worked and tons of coal produced. These data are combined with labor rate estimates from various sources such as union contracts, census data and other sources such as state employment websites to determine a cost per ton for mine labor. Hourly labor costs vary between United Mine Workers of America (UMWA) and non-union mines, and include benefits and payroll taxes. Employees assigned to preparation plants, surface activities, and offices are excluded from this category and are accounted for under coal washing costs and mine overhead. These preparation plants may be located at the mine site or a central preparation plant that washes coal from a number of mines. If the coal is transported to an offsite location for washing, transportation costs to the plant are included in the total costs.

Supply costs are adjusted annually to reflect movements in the price of steel, diesel, natural gas and other commodities. Cost adjustments are averaged on an annual basis and analyzed to ensure that anomalous spikes in commodity prices are not carried forward in the cost analysis.

Royalties, severance taxes, black lung fees, reclamation taxes and property taxes are estimated using federal, state and local parameters.

In the Western United States, capital requirements are estimated for each mine and a life-of-mine discounted cash flow analysis is used to determine the price required to yield a 10% DCFROR[2], including income taxes. In the Eastern United States, the required price is estimated based on operating costs and production levels.

Where information is incomplete, cost items are grouped into categories that can be compared with industry averages by mine type and location. These averages can be adjusted up or down based on new information or added assumptions. The adjustments take the form of cost multipliers or parameter values. Specific cost multipliers are developed with the aid of industry experts and proprietary formulas. This method is at times used to convert materials and supplies, on-site trucking costs and mine and division overhead categories into unit removal costs by equipment type. (This was done in the example shown in Figure 9-3 above.) To check the accuracy of these cost estimates, cash flow analysis of publicly traded companies is used. Mine cash-costs are extracted from corporate cash flows and compared with the initial estimates. Adjustments for discrepancies are made on a case-by-case basis.

Many of the cost assumptions associated with labor and productivity were taken from the Mine Safety Health Administration (MSHA) database. All active mines report information specific to production levels, number of employees and employee hours worked. Wood Mackenzie supplements the basic MSHA data with information obtained from mine personnel interviews and industry contacts. Phone conversations and conferences with industry professionals provide

[1] Overburden refers to the surface soil and rock that must be removed to uncover the coal.

[2] DCFROR stands for discounted cash flow rate of return (also called “internal rate of return” (IRR) and “rate of return”). It is the annualized effective coupounded return that can be earned on invested capital.

additional non-reported information such as work schedules, equipment types, percentages of washed coal, and trucking distances from the mine to wash-plants and load-out terminals.

For each active or proposed mine, Wood Mackenzie reports the estimated cost to take coal from the mine to a logical point-of-sale. The logical point-of-sale may be a truck or railcar load-out or even a barge facility. This is done to produce a consistent cost comparison between mines. Any transport costs beyond the point-of-sale terminal are not part of this analysis and are not reflected in the supply curves themselves. (Transport costs are taken into account using a separate procedure which is described below in section 9.3.)

In cases where new mines are planned or recoverable reserves are available to support new mines (see sections 9.2.6 and 9.2.7 below), Wood Mackenzie uses nearby mines with similar geography and geology to estimate mine operating costs and productivity levels. Production levels for new mines are estimated based on known reserves, historic precedent, and region specific knowledge.

9.2.3 Supply Curve Development

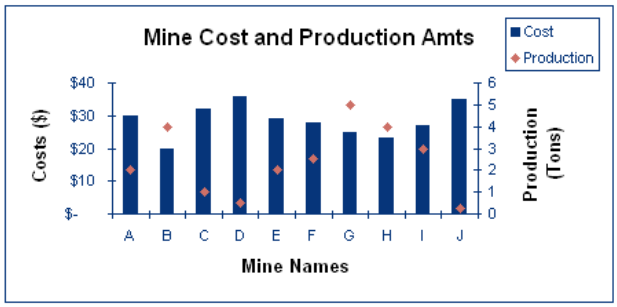
Once costs are estimated for all new or existing mines, they are sorted by cash cost, lowest to highest, and plotted cumulatively by production to form a supply curve. The supply curve then represents all mines – new or existing as well as both underground and surface mines– irrespective of market demand. Mines located toward the bottom of the curve have the lowest cost and are most likely to be developed while the mines at the top of the curve are higher cost and will likely wait to be developed. The process for developing a cumulative supply curve is illustrated in Figure 9-4 and Figure 9-5 below.

Figure 9-4 Illustration of Preliminary Step in Developing a Cumulative Coal Supply Curve

Key

E = EXISTING MINE
N = NEW MINE
U = UNDERGROUND MINE
S = SURFACE MINE

New or Existing?	Mine	Type	Cost	Production
N	A	S	$ 30	2
E	B	U	$ 20	4
N	C	S	$ 32	1
N	D	S	$ 36	0.5
E	E	S	$ 29	2
N	F	S	$ 28	2.5
E	G	U	$ 25	5
E	H	U	$ 23	4
E	I	U	$ 27	3
N	J	S	$ 35	0.25



In the table and graph above, mine costs and production are sorted alphabetically by mine name. To develop a supply curve from the above table the values must be sorted by mine costs from lowest to highest. A new column for cumulative production is added, and then a supply curve graph is created which shows the costs on the 'Y' axis and the cumulative production on the 'X' axis. Notice below that the curve contains all mines – new or existing as well as both underground and surface mines. The resulting curve is a continuous supply curve but can be modified to show costs as a stepped supply curve. (Supply curves in stepped format are used in linear programming models like IPM.) See Figure 9-6 for a stepped version of the supply curve example shown in Figure 9-5. Here each step represents an individual mine, the width of the step reflects the mine's production, and its height shows the cost of production. (See Appendix 9-1 for a more detailed example of how a supply curve is derived from constituent mine costing models.)

Figure 9-5 Illustration of Final Step in Developing a Cumulative Coal Supply Curve

New or Existing?	Mine	Type	Cost	Production	Cum Productio
E	B	U	$ 20	4	4
E	H	U	$ 23	4	8
E	G	U	$ 25	5	13
E	I	U	$ 27	3	16
N	F	S	$ 28	2.5	18.5
E	E	S	$ 29	2	20.5
N	A	S	$ 30	2	22.5
N	C	S	$ 32	1	23.5
N	J	S	$ 35	0.25	23.75
N	D	S	$ 36	0.5	24.25

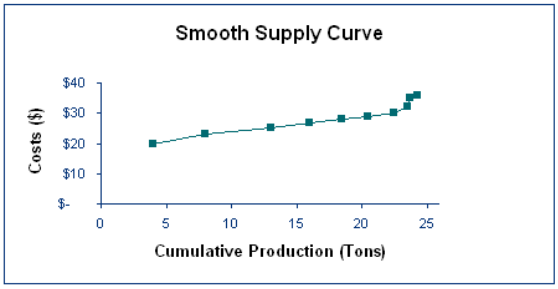
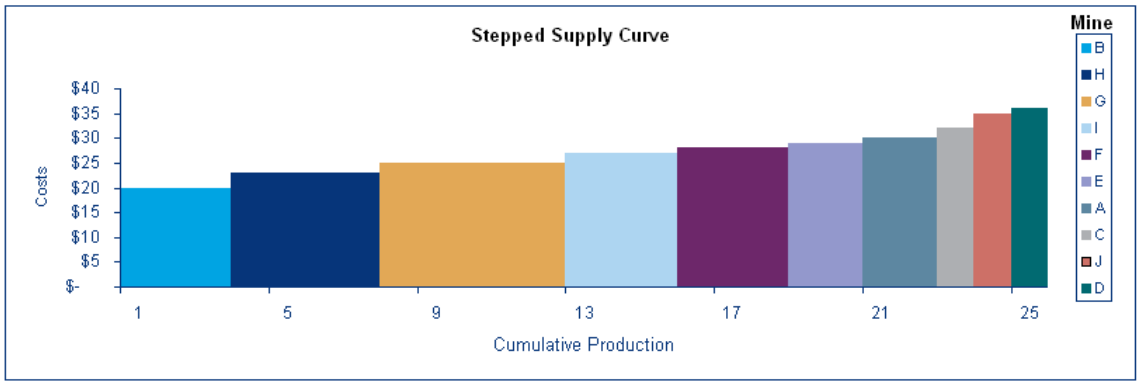


Figure 9-6 Example Coal Supply Curve in Stepped Format



PRODUCTION AMOUNT

MINE NAME →	B	H	G	I	F	E	A	C	J	D
New or Existing	4	8	13	16	18.5	20.5	22.5	24	25	25.5
E	$ 20	-	-	-	-	-	-	-	-	-
E	$ 20	-	-	-	-	-	-	-	-	-
E	$ 20	-	-	-	-	-	-	-	-	-
E	-	$ 23	-	-	-	-	-	-	-	-
E	-	$ 23	-	-	-	-	-	-	-	-
E	-	$ 23	-	-	-	-	-	-	-	-
E	-	$ 23	-	-	-	-	-	-	-	-
E	-	-	$ 25	-	-	-	-	-	-	-
E	-	-	$ 25	-	-	-	-	-	-	-
E	-	-	$ 25	-	-	-	-	-	-	-
E	-	-	$ 25	-	-	-	-	-	-	-
E	-	-	$ 25	-	-	-	-	-	-	-
E	-	-	-	$ 27	-	-	-	-	-	-
E	-	-	-	$ 27	-	-	-	-	-	-
E	-	-	-	$ 27	-	-	-	-	-	-
N	-	-	-	-	$ 28	-	-	-	-	-
N	-	-	-	-	$ 28	-	-	-	-	-
N	-	-	-	-	$ 28	-	-	-	-	-
E	-	-	-	-	-	$ 29	-	-	-	-
E	-	-	-	-	-	$ 29	-	-	-	-
N	-	-	-	-	-	-	$ 30	-	-	-
N	-	-	-	-	-	-	$ 30	-	-	-
N	-	-	-	-	-	-	-	$ 32	-	-
N	-	-	-	-	-	-	-	-	$ 35	-
N	-	-	-	-	-	-	-	-	-	$ 36

Production Scalar

9.2.4 Data Sources Used to Build the Curves

For active mines, data relating to labor and productivity is taken from MSHA databases. MSHA reports on individual mine production, number of employees and employee-hours worked. Corporate financial statements of publicly traded companies are listed with the Securities and Exchange Commission (SEC). Supplemental information on work schedules, equipment, percentages of washed coal, trucking distances between mine and preparation plants is obtained