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.

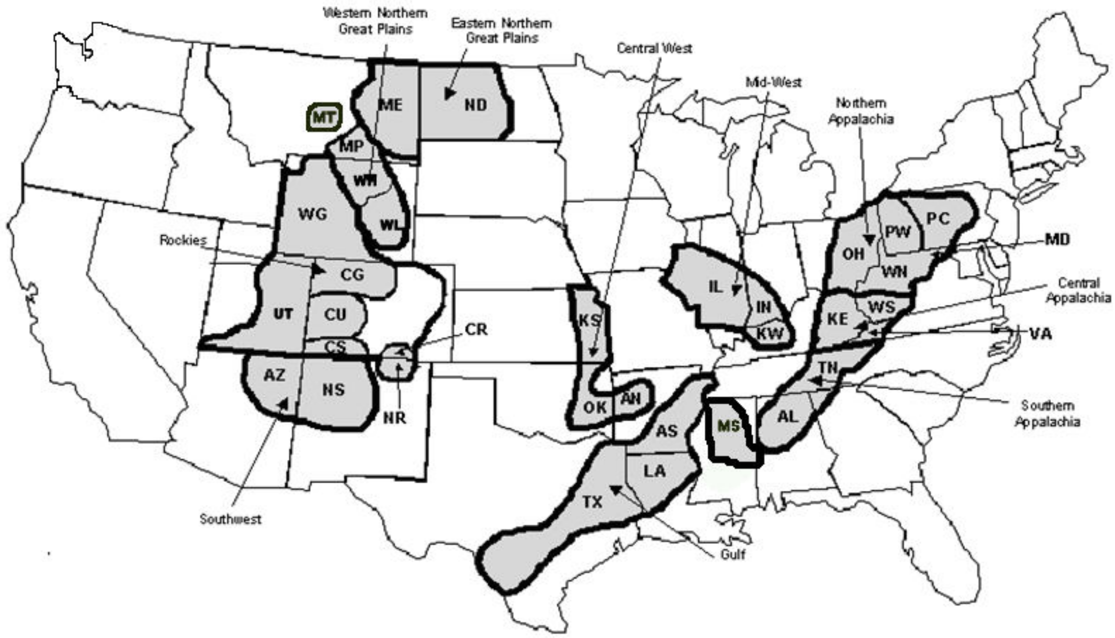
9.1.1 Coal Supply Regions

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	--	--

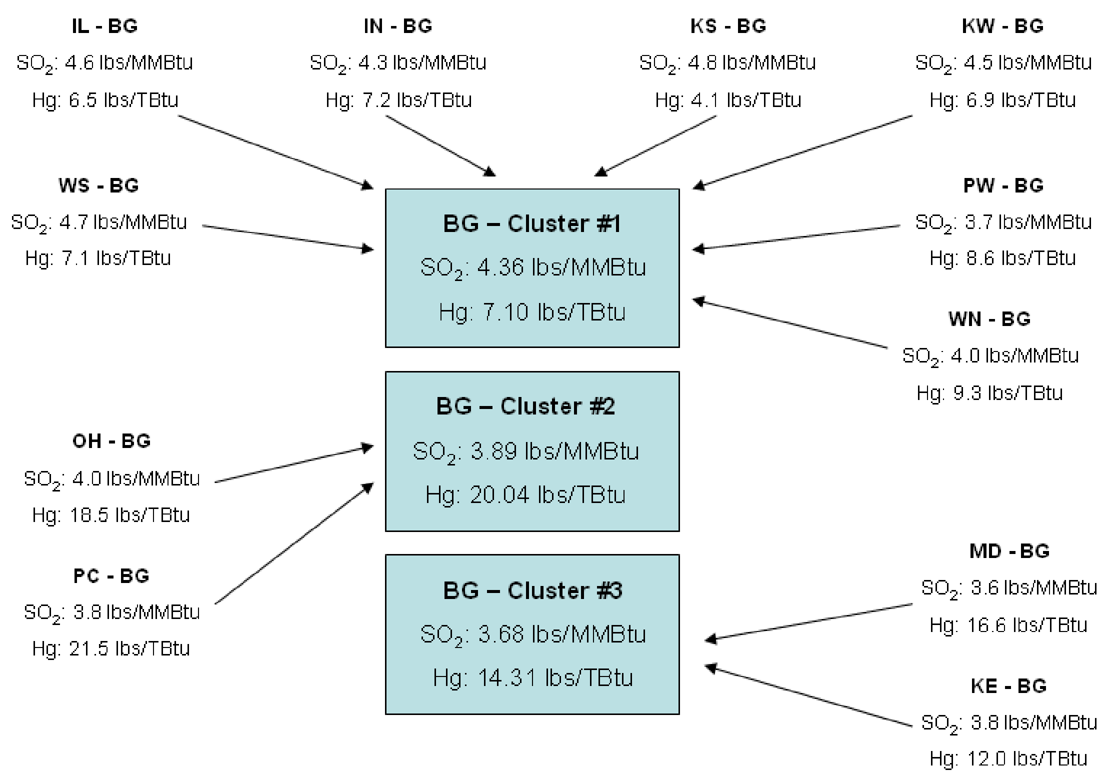
Table 9-8 Ash Emission Factors of Coal Used in EPA Base Case v.4.10

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)

10% DCFROR All cost curves assume mine operators are able to earn a minimum 10% discounted rate-of-return.

Cash Cost

Royalty = Revenue * Royalty %
Severance Tax = (Revenue - Royalty) * Sevr Tax Rate[1] * % Adjustment if needed
Property Tax = (Revenue - Royalty)* property tax rate
Reclamation Tax = Production * reclamation rate[2]
Black Lung = Production * (the lesser of 0.55, or 4.4% * sales price of coal)

DOCs (surface mines)
Labor = Production * (Wages + Benefits) / Productivity
Unit Removal Costs
= Cost per yard $_{\text{by equipment type}}$ * Amount removed
Added coal haul = year-over-year mileage increase * haul rate * production
On-going reclamation = production * reclamation rate (as a function of coal depth)

< OR >

DOCs (deep mines)
Labor = Production * (Wages + Benefits) / Productivity
Materials & Supplies
Trucking costs = haul distance from mine to load-out * haul rate
Mine overhead = Cost associated with mine support
Division overhead = Company dependent costs for operations
Pension = company's portion of employee retirement

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

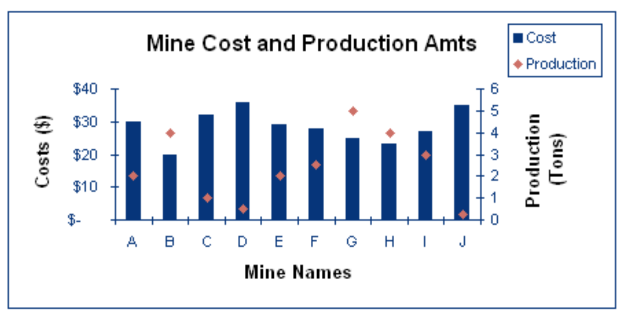
Once costs are estimated for all new or existing mines, they are sorted by cash cost, lowest to highest, and plotted cumulatively by production to form a supply curve. The supply curve then represents all mines – new or existing as well as both underground and surface mines– irrespective of market demand. 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



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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

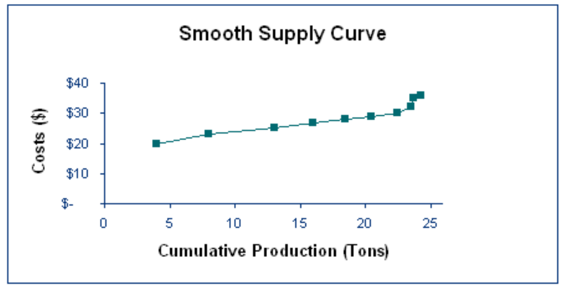

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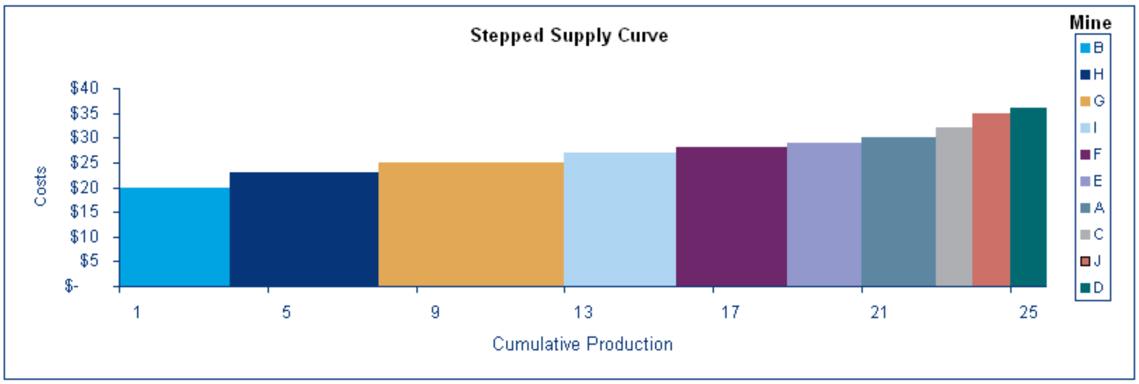
Figure 9-6 Example Coal Supply Curve in Stepped Format



MINE NAME →			B	H	G	I	F	E	A	C	J	D
			PRODUCTION AMOUNT									
New or Existing	Production Scalar		4	8	13	16	18.5	20.5	22.5	24	25	25.5
E		1	$ 20	-	-	-	-	-	-	-	-	-
E		2	$ 20	-	-	-	-	-	-	-	-	-
E		3	$ 20	-	-	-	-	-	-	-	-	-
E		4	-	$ 23	-	-	-	-	-	-	-	-
E		5	-	$ 23	-	-	-	-	-	-	-	-
E		6	-	$ 23	-	-	-	-	-	-	-	-
E		7	-	$ 23	-	-	-	-	-	-	-	-
E		8	-	-	$ 25	-	-	-	-	-	-	-
E		9	-	-	$ 25	-	-	-	-	-	-	-
E		10	-	-	$ 25	-	-	-	-	-	-	-
E		11	-	-	$ 25	-	-	-	-	-	-	-
E		12	-	-	$ 25	-	-	-	-	-	-	-
E		13	-	-	-	$ 27	-	-	-	-	-	-
E		14	-	-	-	$ 27	-	-	-	-	-	-
E		15	-	-	-	$ 27	-	-	-	-	-	-
N		16	-	-	-	-	$ 28	-	-	-	-	-
N		17	-	-	-	-	$ 28	-	-	-	-	-
N		18	-	-	-	-	$ 28	-	-	-	-	-
E		19	-	-	-	-	-	$ 29	-	-	-	-
E		20	-	-	-	-	-	$ 29	-	-	-	-
N		21	-	-	-	-	-	-	$ 30	-	-	-
N		22	-	-	-	-	-	-	$ 30	-	-	-
N		23	-	-	-	-	-	-	-	$ 32	-	-
N		24	-	-	-	-	-	-	-	-	$ 35	-
N		25	-	-	-	-	-	-	-	-	-	$ 36

-

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 in interviews performed for Wood Mackenzie's annually published county-by-county studies. Information on recoverable reserves comes from several sources such as Environmental Impact Statements (EIS), company annual reports, applications filed at state permitting offices or Lease by Application (LBA) filings for mines on federal lands.

For areas where public information is not available or is incomplete, reserves are estimated using geologic reports of nearby properties and some extrapolation by mining engineers and geologists.

9.2.5 Procedure Used In Determining Mine Productivity

Projected production and stripping ratios[3] are the key determinants of surface mine productivity. Wood Mackenzie assumes mining costs increase as stripping ratios increase. The stripping ratio is the quantity of overburden removed relative to the quantity of coal recovered. Assuming that reserves are developed where they are easiest to mine and deliver to market, general theory suggests that as the easy reserves are depleted, greater amounts of overburden must be handled for the same amount of coal production; thus causing a decrease in mining productivity. However, this productivity loss is often offset by technology improvements in labor saving equipment.

While an understanding of the forces affecting productivity is important, no attempt is made to develop a complex algorithm that tries to balance increased stripping ratios with added technology improvements. Instead, Wood Mackenzie uses reported aggregate productivity (in tons per employee hour) provided by MSHA as a starting point and divides the production by the productivity calculation to obtain aggregate employee-hours. Allocating aggregate employee hours among specific mines, production forecasts for these mines can be converted back into mine-specific productivity forecasts. These forecasts are then examined on a mine-by-mine basis by an industry expert with region specific knowledge.

A similar approach is used for underground mines. First, as background, the specific factors affecting productivity at such mines are identified. For example, underground mines do not have stripping ratios. Productivity estimates for these mines largely depend on the type of mining technique used (which is a function of the region's geology). For instance, longwall-mines can produce a high volume of low cost coal but geologic constraints like small reserve blocks and the occurrence of faulting tends to limit this technique to certain regions. In addition to geologic constraints, there are many variables that can impact underground-mine productivity but they are often difficult to quantify and forecast.

These factors are not used directly but provide a backdrop for deriving productivity estimates. As with surface mines Wood Mackenzie relies on MSHA data for its productivity estimates. Productivity estimates for underground mines start with the MSHA estimates and are carried forward into the forecast years without adjustment.

9.2.6 Procedure to Determine Total Recoverable Reserves by Region and Type

Before mine operators are allowed to mine coal, they must request various permits, conduct environmental impact studies (EIS) and, in many cases, notify corporate shareholders. In each of these instances, mine operators are asked to estimate annual production and total recoverable reserves. Wood Mackenzie uses the mine operators' statements as the starting point for production and reserves forecasts. If no other material is available, interviews with company personnel will provide an estimate.

Region and coal type determinations for unlisted reserves are based on public information reported for similarly located mines. Classifying reserves this way means considering not only a

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[3] Stripping ratio is the amount of waste material (rock and/or soil) that must be removed to recover one unit (commonly expressed in short tons) of coal. For example, a stripping ratio of 9.8 means that to recover 1 ton of coal you must remove 9.8 tons of waste material. A lower stripping ratio means that less waste has to be removed.

mine's geographic location but also its geologic conditions such as depth and type of overburden and the specific identity of the coal seam(s) being mined. For areas where public information is not available or is incomplete, Wood Mackenzie engineers and geologists estimate reserve amounts based on land surveys and reports of coal depth and seam thickness provided by the U.S. Geologic Service (USGS). This information is then used to extrapolate reserve estimates from known coal sources to unknown sources. Coal quality determinations for unknown reserves are assigned in much the same way.

Once a mine becomes active, actual production numbers reported in corporate SEC filings and MSHA reports are subtracted from the total reserve number to arrive at current reserve amounts. Wood Mackenzie consistently updates the reserves database when announcements of new or amended reserves are made public. As a final check, the Wood Mackenzie supply estimates are balanced against the Demonstrated Reserve Base (DRB)[4] estimates to ensure that they do not exceed the DRB estimates.

9.2.7 New Mine Assumptions

New mines have been included based on information that Wood Mackenzie maintains on each supply region. They include announced projects, coal lease applications and unassigned reserves reported by mining companies. Where additional reserves are known to exist, additional incremental steps have been added. These incremental steps were added based on characteristics of the specific region, typical mine size, and cost trends. They do not necessarily imply a specific mine or mine type.

9.2.8 Other Notable Procedures

Cost Rounding

For simplification, the estimated mine costs were rounded so that costs less than 20 $/Ton were rounded to the nearest $0.25. Costs that fell between 20 and 50 $/Ton were rounded to the nearest $0.50 and costs greater than $50 were rounded to the nearest $1.00.

<=$20, round to nearest $0.25
>$20 and <=$50, round to nearest $0.50
>$50, round to nearest $1.00

Future Cost Adjustments

For consistency with the cost basis used in EPA Base Case v.4.10, costs are converted to real 2007$. Wood Mackenzie has assumed that improved productivity will lead to cost reductions in all regions except Central Appalachia where depleting reserves will lead to falling productivity and increased costs. Costs for all regions except Central Appalachia have been reduced at a rate of 0.4%/year. Central Appalachia's costs have been increased at a rate of 0.4%/year based on the assumption that labor costs on average account for 40% of the Cost of Production. These regional cost adjustments are derived from specific factors affecting costs in regions based on information maintained by Wood Mackenzie and their on-going dialog with industry professionals.

9.2.9 Region Specific Assumptions and Outlooks

Powder River Basin (PRB)

Powder River Basin cost curves are based on cost models run for each of the identified projects in Wood Mackenzie's coal supply database. These cost models are run on five year increments over a 20 year mine life. These models assume that federal lease tracts are acquired as necessary to achieve a 20 year mine life. In preparing the curves for EPA, it was assumed that existing mines would operate at projected levels through 2011 and reserves were adjusted to reflect remaining reserves at that time. Ten years additional reserves were then added to the remaining reserves

[4]Posted by the Energy Information Administration (EIA) in its January, 2007 Coal Production Report.

based on the assumption that additional reserves would be available for lease and the mines would continue to operate. Costs for the added reserves were increased by $3.00/ton to reflect increased coal leasing costs and increasing mining ratios in the PRB.

One existing mine, Decker, is expected to close prior to 2012 and was therefore not included in the cost curves.

A MT region was added to accommodate two proposed mines in Montana that do not fit the quality specifications for the ME or MP regions.

There is an annual limit of 612 million tons per year on Wyoming PRB coal production (i.e., coal codes WH and WL in Table 9-11) based on expected maximum production from existing mines plus potential production from four identified projects.

Western Bituminous Coalfields
The Western Bituminous Coalfields include the Colorado, Utah, southern Wyoming, New Mexico and Arizona coalfields. Life-of-mine costs are used for all operating mines and identified projects. Reserves have been reduced based on projected production through 2011 for existing mines and mines that are expected to go into production before 2012. Unlike the PRB no additional reserves have been added to the reserve base for existing mines.

Arizona mine costs are FOB[5] mine.

In Utah all costs except Deer Creek's include transportation to a loadout facility. Deer Creek costs are based on delivery to the Huntington Canyon power plant.

In New Mexico, all costs are FOB rail or FOB mine. It is assumed that the Navajo, San Juan Underground and the proposed Navajo South/Desert Rock mine will serve their respective mine-mouth power plants. One existing mine, McKinley, will be mined out by 2012. The proposed Carrizozo mine in SE New Mexico is included in the curve.

In Colorado all costs are FOB mine. This includes the Deserado mine which currently ships all of its production to the Bonanza power plant via a private railroad. A CR region has been added to accommodate two proposed mines in or near the Raton Basin.

Louisiana (LA)/ Mississippi (MS)
Louisiana cost curves are based on Wood Mackenzie cost models for existing and planned mines in Louisiana. Where a mine's reserves exceed production requirements over the forecast period, it has been assumed that a second mine could be opened on the reserves. A high cost mine with cost of $50/ton was added.

A Mississippi cost curve was added.

Montana Lignite (ME)
Montana Lignite curves are based on Wood Mackenzie cost estimates for GNP lignite properties. All costs are FOB mine. Because lignite typically does not ship well, it is assumed that any new mines will be developed to serve mine mouth customers.

[5] FOB stands for "Free On Board" or "Freight on Board." It indicates the point at which responsibility and costs for a goods is transferred from the seller (or shipper) to the buyer. "FOB mine" implies that the price includes costs up to the mine and that the buyer assumes costs beyond the mine. "FOB rail" implies the prices includes the cost of loading the coal onto a rail car.

North Dakota Lignite (ND)
North Dakota curves are based on Wood Mackenzie cost estimates for the region. Where a mine's reserves exceed production requirements over the forecast period, it has been assumed that a second mine could be opened on the reserves. Costs for the new mines were increased by \$2.00/ton. A GNP project was added as a high cost new mine.

Oklahoma/Kansas (OK, KS)
The 2006 set of coal supply curves developed for EPA by Hill and Associates (now a unit of Wood Mackenzie) was updated by increasing costs 30% and adding a high cost mine with a cost of \$100/ton.

Texas Lignite
Texas Lignite cost curves are based on cost models run for each of the existing mines and identified projects in Wood Mackenzie's coal supply database. Big Brown was deleted for the existing mines as its reserves will be depleted before 2011.

Illinois Basin (IL, IN, KW)
Illinois Basin cost curves are based on cost models run for each of the existing mines and identified projects in Wood Mackenzie's coal supply database. Where additional reserves are known to be available, additional next step mines were added based on information maintained by Wood Mackenzie on the region.

Appalachia (AL, OH, PC, PW, TN, VA, WN & WS)
Appalachian cost curves are based on Wood Mackenzie's extensive database of existing and planned mines. 2012 production and cost curves were prepared for each region and coal grade using the regional model to estimate cost, production and reserve data for existing mines. To protect the proprietary nature of the regional curves, mine data were aggregated to produce a curve similar to the regional curve without disclosing specific mine data. Cost and production estimates for each of the next step mines were prepared for each region and coal type based on information maintained by Wood Mackenzie's knowledge for each region.

9.2.10 Explanation of Coal Supply Curve Extensions to 2040
Wood Mackenzie added additional reserves at increased costs on a mine-by-mine basis for each region based on its extensive coal resource database and knowledge of the coal industry. A list of the mines added by region and coal grade can be found in Appendix 9-2. For modeling purposes the 2040 coal supply curves are used in 2050 as well.

9.3 Coal Transportation
Within the United States, steam coal for use in coal-fired power plants is shipped via a variety of transportation modes, including barge, conveyor belt, rail, truck, and lake/ocean vessel. A given coal-fired plant typically only has access to a few of these transportation options and, in some cases, only has access to a single type. The number of transportation options that a plant has when soliciting coal deliveries influences transportation rate levels that plant owners are able to negotiate with transportation providers.

Within the Eastern United States, rail service is provided predominately by two major rail carriers in the region, Norfolk Southern (NS) and CSX Transportation (CSX). Within the Western United States, rail service is also provided predominately by two major rail carriers, Burlington Northern Santa Fe (BNSF) and Union Pacific (UP). Plants in the Midwestern United States may have access to rail service from BNSF, CSX, NS, UP, the Canadian National (CN), Canadian Pacific (CP), or short-line railroads. Barge, truck, and vessel service is provided by multiple firms, and conveyor service is only applicable to coal-fired plants directly located next to mining operations (e.g., mine-mouth plants).

In recent years, transportation rates (especially rail rates) have increased significantly due to significant increases in input costs (including fuel prices, steel prices and labor costs), as well as a number of Surface Transportation Board (STB) rail rate case decisions that have allowed higher rail rates to be charged at plants that are served only by a single railroad.

The transportation methodology and rates presented below reflect expected long-run equilibrium transportation rates as of September 2008, when the coal transportation rate assumptions for EPA Base Case v.4.10 were finalized. It is important to remember that these rates do not reflect rates that transporters and coal-fired owners may currently be negotiating in the near-term (pre-2012). Instead, these rates reflect expected long-term equilibrium levels, including the long-term market dynamics that will drive these pricing levels.

All rates are represented in 2007 real dollars.

9.3.1 Coal Transportation Matrix Overview

Description

In order to model coal transportation rates within the EPA's modeling construct, a coal transportation matrix was developed, which represents a matrix of all the coal demand regions and coal supply regions modeled within the IPM model for EPA Base Case v.4.10. The matrix includes the associated transportation costs between these supply and demand nodes. Each coal demand region covers a set of coal plants having similar transportation infrastructure, transportation competitiveness levels, and geographic location; in addition to these criteria, coal demand regions are also classified as either "mine-mouth" or "non mine-mouth" regions. Coal supply regions are represented by the major coal mining basins modeled in IPM; a more detailed discussion on these regions can be found in previous sections.

Methodology

Each coal supply region and coal demand region is connected via a transportation link, which can include multiple transportation modes. For each transportation link, cost estimates, in terms of $/ton, were calculated utilizing mode-based transportation cost factors, analysis of the competitive nature of the moves, and overall distance that the coal type must move over each applicable mode. An example of the calculation methodology for movements including multiple transportation modes is shown in Figure 9-7.

Figure 9-7 Calculation of Multi-Mode Transportation Costs (Example)

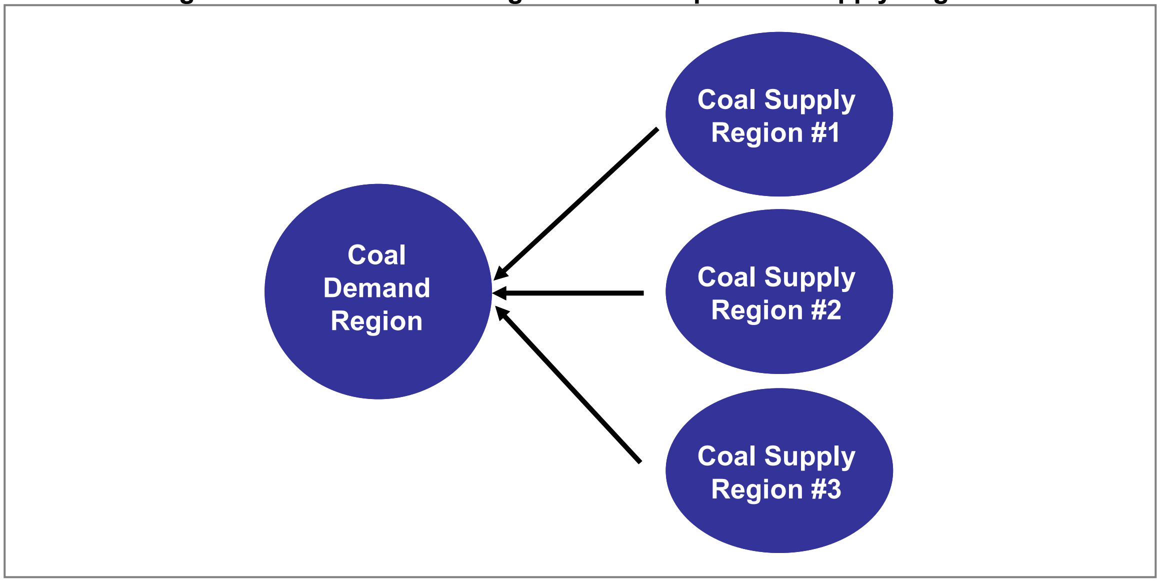
Rail Cost ($/ton) = Rail Mill Rate (mills/ton-mile) x Rail Mileage + Transloading Cost ($/ton) + Barge Cost ($/ton) = Loading Cost ($/ton) + Barge Mill Rate (mills/ton-mile) x Barge Mileage

9.3.2 Calculation of Supply/Demand Region Distances

Definition of applicable supply/demand regions

Coal demand regions are linked to coal supply regions based on historical coal deliveries, as well as based on the potential for new coal supplies to serve a demand region going forward. A demand region may have transportation links with more than one supply region, depending on the various coal types that can be physically delivered and burned by generators within a given coal demand region.

Figure 9-8 Coal Demand Region with Multiple Coal Supply Regions



Transportation Links for Existing Coal-Fired Plants
Transportation routings for given coal supply regions and coal demand regions were developed based on third-party software[6] and other industry knowledge available to Hellerworx and PA Consulting Group. Origins for each coal supply region were based on significant mines or other significant delivery points within the supply region, and destinations for each coal demand region were based on geographical points located near, and with similar key delivery transportation characteristics, as the coal plants located within the given coal demand region. For routes utilizing multiple modes (e.g. rail-to-barge, truck-to-rail, etc.), distances were developed separately for each transportation mode.

Transportation Links for New Coal-Fired Plants
Within each coal demand region, coal transportation links representative of the typical transportation costs expected to be incurred by new coal plants within that region were developed. For coal demand regions where new coal plant construction is not expected to include mine-mouth plants, the transportation links for new plants are based on transportation links in the existing coal demand region that are expected to have costs most similar to those incurred by new plants. For coal demand regions where new coal plant construction is expected to consist primarily of mine-mouth plants, new transportation links reflecting short-distance transportation of local coal supplies were created as needed to properly represent the transportation costs incurred by new plants. This methodology helps ensure that coal transportation costs for new coal plants are properly integrated with and assessed fairly vis-à-vis existing coal-fired assets within the IPM modeling structure.

9.3.3 Overview of Rail Rates
Competition within the railroad industry is limited. Two major railroads in the Western U.S. (BNSF and UP) and two major railroads in the Eastern U.S. (CSX and NS) currently originate most of the U.S. coal traffic that moves by rail.

In recent years, railroads have increased coal transportation rates in real terms wherever they have the opportunity. However, rail rates at plants captive to a single rail carrier are now close to the maximum levels prescribed by the STB, which limits the potential for further real increases in these rates. Moreover, between 2004 and 2008, the differential between rates at captive plants and rates at competitively-served plants narrowed. For all of the coal supply regions except the

[6] Rail routing and mileage calculations utilize ALK Technologies PC*Miler software.

Powder River Basin (PRB), the current relatively small differentials between captive and competitive rates are expected to persist over the long-term.

All of the rail rates discussed below include railcar costs, and include fuel surcharges at expected 2012 fuel price levels.

Overview of Rail Competition Definitions
Within the transportation matrix, rail rates are classified as being either captive or competitive, depending on the ability of a given coal demand region to solicit supplies from multiple suppliers. Competitive rail rates are further subdivided into high- and low-cost competitive subcategories. Competition levels are affected both by the ability to take delivery of coal supplies from multiple rail carriers, the use of multiple rail carriers to deliver coal from a single source (e.g., BNSF/UP transfer to NS/CSX for PRB coal moving east), or the option to take delivery of coal via alternative transportation modes (e.g., barge, truck or vessel).

Table 9-12 Rail Competition Definitions

Competition Type	Definition
Captive	Demand source can only access coal supplies through a single provider; demand source has limited power when negotiating rates with railroads.
High-Cost Competitive	Demand source has some, albeit still limited, negotiating power with rail providers; definition typically applies to demand sources that have the option of taking delivery from either of the two major railroads in the region.
Low-Cost Competitive	Demand source has a strong position when negotiating with railroads; typically, these demand sources also have the option of taking coal supplies via modes other than rail (e.g., barge, truck, or lake/ocean vessel).

Rail Rates
As previously discussed, rail rates are subdivided into three competitive categories: captive, high-cost competitive, and low-cost competitive. Moves are further subdivided based on the distance that the coal supply must move over rail lines: <200 miles, 200-299 miles, 300-399 miles, 400-699 miles, and 700+ miles. Within the Western U.S., mileages are only subdivided into two categories (<300 miles and 300+ miles), given the longer distances that these coal supplies typically move.

Initial rate level assumptions were determined based on an analysis of recent rate movements, current rate levels in relation to maximum limits prescribed by the STB, expected coal demand, diesel prices, recent capital expenditures by railroads, and projected productivity improvements. In general, shorter moves result in higher applicable rail rates due to the lesser distance over which fixed costs can be spread. As previously discussed, rail rates reflect anticipated 2012 costs in 2007 real dollars.

Rates applicable to Eastern moves
Rail movements within the Eastern U.S. are handled predominately by the region's two major carriers, NS and CSX. Some short movements are handled by a variety of short-line railroads. Most plants in the Eastern U.S. are served solely by a single railroad (i.e., they are captive plants).

Table 9-13 Assumed Eastern Rail Rates (2007 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	72	72	58
200-299	55	55	43
300-399	55	55	43
400-699	37	37	30
700+	35	35	28

Rates applicable to Midwestern moves

Plants in the Midwestern U. S. may be served by BNSF, CN, CP, CSX, NS, UP or short-line railroads. However, the rail network in the Midwestern U.S. is very complex, and most plants are served by only one of these railroads. The Midwestern U.S. also includes a higher proportion of barge-served and truck-served plants than is the case in the Eastern or Western U.S.

Table 9-14 Assumed Midwestern Rail Rates (2007 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	72	72	58
200-299	55	55	43
300-399	55	55	43
400-699	36	36	29
700+	34	34	27

Rates applicable to Western moves

Rail moves within the Western U.S. are handled predominately by BNSF and UP. In addition to these incumbent carriers, CP acquired the Dakota, Minnesota and Eastern Railroad (DM&E) in October 2007, which increases the probability that DM&E's project to build a third rail line into the PRB will be completed. The analysis assumes that DM&E's entry into the market will influence transportation rates for PRB coal by 2012,[7] and the rail rate forecast for PRB coal shipments to competitively-served destinations reflects this expectation.

Rates for Western coal shipments from the PRB are forecast separately from rates for Western coal shipments from regions other than the PRB. This reflects the fact that in many cases coal shipments from the PRB are subject to competition between BNSF and UP (with the possible future entry of DM&E as a third competitor within this region), while rail movements of Western coal from regions other than the PRB consist primarily of Colorado and Utah coal shipments that originate on UP, and New Mexico coal shipments that originate on BNSF. PRB coal shipments also typically involve longer trains moving over longer average distances than coal shipments from the other Western U.S. coal supply regions, which means these shipments typically have lower costs per ton-mile than non-PRB coal shipments.

[7] Note that this is not equivalent to assuming that DM&E's PRB project would be operational by 2012. Construction of the DM&E's PRB project is expected to be a three-year process. However, in order to obtain financing and begin construction, DM&E would likely have to negotiate some rail contracts for PRB coal shipments. Thus, DM&E's presence as a third competitor in the market for PRB coal shipments might affect rail rates well before DM&E's additional rail line into the PRB became operational

Non-PRB coal moves

Table 9-15 Assumed Non-PRB Western Rail Rates (2007 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	43	43	35
300+	25	21	21

PRB moves confined to BNSF/UP rail lines

Table 9-16 Assumed PRB Western Rail Rates (2007 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	43	43	35
300+	23	14	14

PRB moves transferring to Eastern railroads

For PRB coal moving west-to-east, the coal transportation matrix assumes that the applicable low-cost competitive assumption is applied to the BNSF/UP portion of the rail mileage, and an assumption of either $2.16 per ton or 28 mills per ton-mile (whichever is higher) is applied to the portion of the movement that occurs on railroads other than BNSF and UP. (The $2.16 per ton assumption is a minimum rate for short-distance movements of PRB coal on Eastern railroads.)

9.3.4 Truck rates

Truck rates include loading and transport components, and all trucking flows are considered competitive because highway access is open to any trucking firm. The truck rates shown in Table 9-17 are expected long-term equilibrium levels reflective of current rates as of September 2008, and expected changes in labor costs, fuel prices, and steel prices. The slightly higher truck rates in Utah reflect market conditions specific to that market, which is relatively remote.

Table 9-17 Assumed Truck Rates (2007 Real Dollars)

Market	Loading Cost ($/ton)	Transport (mills/ton-mile)
Outside of Utah Market	1.03	134
Utah Market	1.54	134

9.3.5 Barge and Lake Vessel Rates

As with truck rates, barge rates include loading and transport components, and all flows are considered competitive because river access is open to all barge firms. The transportation matrix subdivides barge moves into three categories, which are based on the direction of the movement (upstream vs. downstream) and the size of barges that can be utilized on a given river. As with the other types of transportation rates forecast in this analysis, the barge rate levels shown in Table 9-18 are expected long-term equilibrium levels reflective of current rates as of September 2008, and expected changes in labor costs, fuel prices, and steel prices.

Rates for transportation of coal by lake vessel on the Great Lakes were forecast on a plant-specific basis, taking into account the lake vessel distances applicable to each movement, the expected backhaul economics applicable to each movement (if any), and the expected changes in labor costs and fuel and steel prices over the long-term.

Table 9-18 Assumed Barge Rates (2007 Real Dollars)

Type of Barge Movement	Loading Cost ($/ton)	Transport (mills/ton-mile)
Mississippi River, and Downstream on the Ohio River	1.75	7.9
Smaller Size Barges (Allegheny, Kanawha, and Monongahela Rivers)	1.85	6.9
Upstream on Ohio River	1.95	10.4

9.3.6 Transportation Rates for Imported Coal

Transportation rates for imported coal reflect expectations regarding the long-term equilibrium level for ocean vessel rates, taking into account expected long-run equilibrium levels for fuel and steel prices, and expected continued strong demand for shipment of dry bulk commodities (especially coal and iron ore) from China and other Asian nations.

In EPA Base Case v.4.10, it is assumed that imported coal is likely to be used only at plants that can receive this coal by direct water delivery (i.e., via ocean vessel or barge delivery to the plant). This is based on an assessment of recent transportation market dynamics, which suggests that railroads are unlikely to quote rail rates that will allow imported coal to be cost-competitive at rail-served plants. Moreover, import rates are higher for the Alabama and Florida plants than for New England plants because many of the Alabama and Florida plants are barge-served (which requires the coal to be transloaded from ocean vessel to barge at an ocean terminal, and then moved by barge to the plant), whereas most of the New England plants can take imported coal directly by vessel. Transportation rates for imported coal moving to each coal demand region are shown in Table 9-19.

Table 9-19 Assumed Transportation Rates for Imported Coal (2007 Real Dollars)

Coal Demand Region	Coal Demand Region Description	Transportation Rate ($/ton)
ALR2	Alabama rail plants (ALRL)_Low-Cost Competitive Not Mine Mouth Barge	15.43
FL2	Florida plants (FL)_Low-Cost Competitive Not Mine Mouth Barge	15.43
FL3	Florida plants (FL)_Low-Cost Competitive Not Mine Mouth Rail	15.43
GFB1	Gulf barge plants (GFBG)_Low Cost Competitive Not Mine Mouth Rail	15.43
GFB3	Gulf barge plants (GFBG)_Low-Cost Competitive Not Mine Mouth Barge	15.43
NE2	New England / Hudson River plants / Hudson plant (NE)_Low-Cost Competitive Not Mine Mouth Barge	11.32
NE3	New England / Hudson River plants / Hudson plant (NE)_Low-Cost Competitive Not Mine Mouth Rail	13.37
TAB1	Tennessee and Northern Alabama river plants (TABG)_High-Cost Competitive Not Mine Mouth Rail	15.43

9.3.7 Other Transportation Costs

In addition to the transportation rates already discussed, the transportation matrix assumes various other rates that are applied on a case-by-case basis, depending on the logistical nature of a move. These charges apply when coal must be moved between different transportation modes (e.g., rail-to-barge or truck-to-barge) – see Table 9-20.

Table 9-20 Assumed Other Transportation Rates (2007 Real Dollars)

Coal Demand Region	Rate ($/ton)
Rail-to-Barge	1.23
Rail-to-Vessel	1.23
Rail-to-Rail	1.44
Truck-to-Barge	1.49
Conveyor	1.13

9.3.8 Long-Term Escalation of Transportation Rates

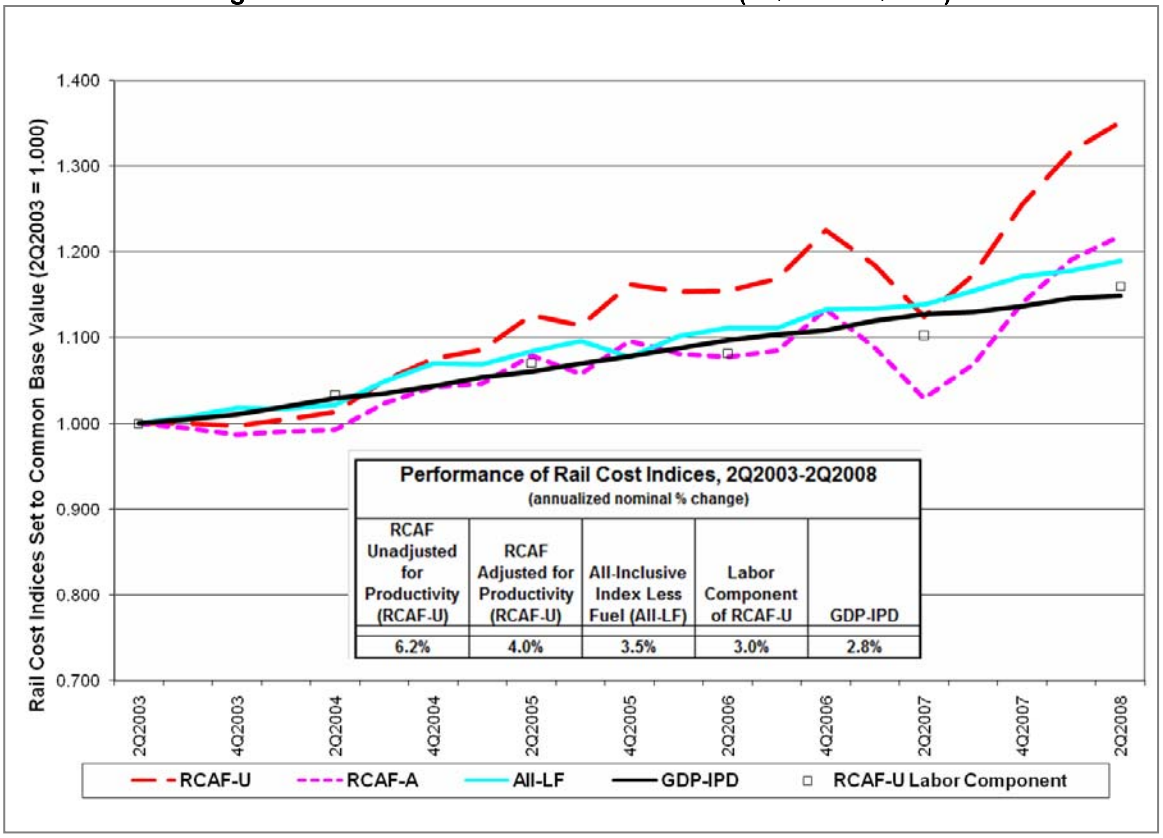
Overview of market drivers

According to data published by the Association of American Railroads (AAR), labor costs accounted for about 34% of the rail industry's operating costs in 2006, and fuel accounted for an additional 19%. The remaining 47% of the rail industry's costs relate primarily to locomotive and railcar ownership and maintenance, and track construction and maintenance.

The RCAF[8] Unadjusted for Productivity (RCAF-U), which tracks operating expenses for the rail industry, has increased at an annualized rate of 6.2%/year over the past five years, more than double the increase of 2.8%/year in general inflation (GDP-IPD) over the same period. However, this largely resulted from steep increases in diesel fuel prices. Excluding fuel, the rail industry's operating costs (as measured by the All-Inclusive Index Less Fuel, or AII-LF), increased by only 3.5%/year.

[8] The Rail Cost Adjustment Factor (RCAF) refers to several indices created for regulatory purposes by the STB, calculated by the AAR, and submitted to the STB for approval. The indices are intended to serve as measures of the rate of inflation in rail inputs. The meaning of various RCAF acronyms that appear in this section can be found in the insert in Figure 9-9.

Figure 9-9 Rail Cost Indices Performance (2Q2003-2Q2008)

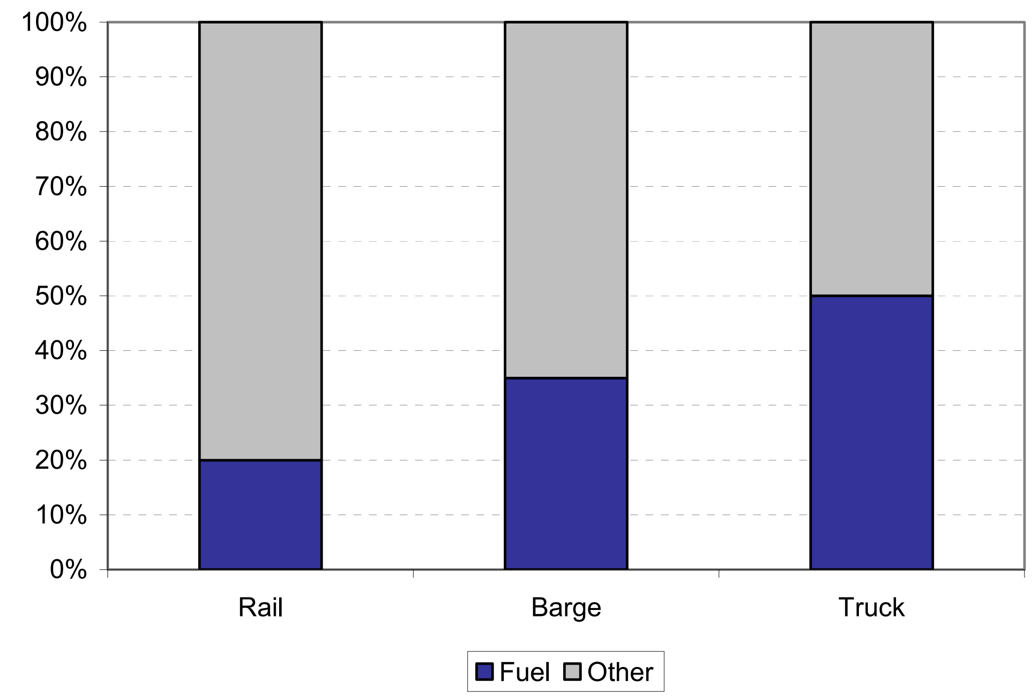


In addition to diesel fuel price increases, world prices for steel (which is a significant component of locomotive, railcar, and track construction and maintenance costs) also increased steeply over the past five years, rising from about $290/metric tonne as of June 2003 to about $650/metric tonne as of June 2007, and over $1,000/metric tonne as of June 2008. However, during the previous five years (2Q1998-2Q2003), when steel prices were less volatile, the All-LF closely tracked general inflation, rising at about 2.1%/year compared with 2.0%/year for the GDP-IPD.

Additionally, over the past five years, the rate of increase in the rail industry's labor costs (3.0%/year) has closely tracked the increase in the GDP-IPD (2.8%/year.)

The other major transportation modes used to ship coal (barge and truck) have cost drivers broadly similar to those for rail transportation (labor costs, fuel costs, and equipment costs). However, a significant difference in cost drivers between the transportation modes relates to the relative weighting of fuel costs for the different transportation modes. Estimates show that, at 2006 fuel prices, fuel costs accounted for about 20% of long-run marginal costs for the rail industry, 35% of long-run marginal costs for barges, and 50% of long-run marginal costs for trucks.

Figure 9-10 Long-Run Marginal Cost Breakdown by Transportation Mode



9.3.9 Market Drivers Moving Forward

Diesel fuel prices

The Energy Information Administration's (EIA's) Annual Energy Outlook (AEO)[9] forecast of long-term equilibrium prices for diesel fuel shows expected prices ranging from about $2.62/gallon in 2012 to about $2.77/gallon in 2030 (2007 real dollars). This range of prices is comparable to the actual average on-highway diesel fuel price for 2006 which was $2.78/gallon (2007 real dollars). The coal transportation rate forecast for EPA Base Case v.4.10 assumes that diesel fuel prices will return to these long-run equilibrium levels by 2012.

Table 9-21 EIA AEO Diesel Fuel Forecast, 2012-2030 (2007 Real Dollars)

Year	Rate ($/gallon)
2012	2.62
2015	2.49
2020	2.57
2025	2.61
2030	2.77
Annualized % Change, 2025-2030	1.10%

Source: EIA

[9] As noted at the beginning of this section, the coal transportation rate assumptions for EPA Base Case v.4.10 were finalized in September 2008. At that time, the Annual Energy Outlook 2008 forecast was the latest available.

Iron ore prices
ABARE's[10] forecast of iron ore prices shows an expectation that iron ore prices will return to late 2007/early 2008 levels (i.e., to the levels prevailing before the most recent price spike) by 2012, and to decline by about 18% in real terms for their 5-year forecast period (2008-2013) as a whole.

Table 9-22 ABARE Forecast of Iron Ore Prices

	2007 $/metric tonne
ABARE Estimate of Average Price for Australian Iron Ore Exports, Year Ending (YE) March 2008	67.72
ABARE Forecast for YE Mar 2009	98.68
ABARE Forecast for YE Mar 2010	91.19
ABARE Forecast for YE Mar 2011	73.73
ABARE Forecast for YE Mar 2012	61.84
ABARE Forecast for YE Mar 2013	55.52
Total Percent Change (2008-2013)	-18.00%

Source: ABARE, Australian Commodities, vol. 15 no. 1 and 2, March and June Quarters 2008

Labor costs
Labor costs for the rail industry are expected to continue to escalate at approximately the same rate as overall inflation (i.e., labor costs are expected to be approximately flat in real terms). Due to the fact that competition is stronger in the barge and trucking industries than in the rail industry, labor costs in the barge and truck industries are likely to increase at rates similar to or slightly slower than the increase in rail labor costs.

Productivity gains
The most recent data published by AAR (covering 2002-2006) shows that rail industry productivity increased at an annualized rate of approximately 1.2% per year during this period. However, due to limited competition in the rail industry, these productivity gains were generally not passed through to shippers. In addition, the potential for significant productivity gains in the trucking industry is relatively limited since truck load sizes, operating speeds, and truck driver hours are all regulated by law.

Long-Term Escalation of Coal Transportation Rates
Based on the foregoing discussion, the transportation rate forecast assumes flat real escalation of rail and truck rates, and a 1% per year real decline in barge and lake vessel rates, which reflects some pass-through of productivity gains in those highly competitive industries, over the 2012-2025 period.

However, EIA's forecast of diesel fuel prices, which is essentially flat in real terms during the 2012-2025 period, predicts a relatively steep rise in diesel fuel prices (annualized increase of 1.1%/year) between 2025 and 2030. Because of this, coal transportation rates are assumed to escalate as follows during the 2026-2062 period:

- Rail: 1.1% annual real increase in fuel prices x 20% fuel cost weighting = real rate increase of 0.2%/year.
- Truck: 1.1% annual real increase in fuel prices x 50% fuel cost weighting = real rate increase of 0.5%/year.

[10] ABARE is a branch of the Australian government that forecasts prices and trade volumes for a wide variety of commodities that Australia exports. Australia is a major exporter of iron ore, accounting for about 32% of total worldwide iron ore exports in 2007. See www.abareconomics.com

- Barge and lake vessel: 1.1% annual real increase in fuel prices x 35% fuel cost weighting = real input cost increase of 0.4%/year, less 1% per year for pass-through of productivity gains = real rate decline of 0.6%/year.
- Conveyor: no change in real terms throughout the study period.

9.3.10 Other Considerations

Transportation constraints limiting the growth of PRB coal use

The rate at which coal shipments from the PRB (Montana and Wyoming) regions can be increased is somewhat limited in the near-term by the capacity of the rail lines that transport the coal from these regions. Hence, the following limits on the growth of PRB coal production are implemented in IPM:

- Wyoming PRB coal growth is limited to 15 million short tons additional production capacity each year.
- Montana coal growth is limited to 2 million short tons additional production capacity each year.

Table 9-23 Assumed Production Growth Rates

Coal Supply Source	Growth/Year (MM short tons)
Wyoming PRB	15
Montana	2

Other transportation constraints

This analysis does not consider the February 10, 2009 announcement by Norfolk Southern and Canadian National Railway to share rail lines and enhance the efficiency of service out of the Illinois Basin coal supply region (Mid-American Corridor). This announcement has the potential to alleviate an existing bottleneck (both rate-based and logistical-based) that has historically prevented large volumes of coal moving from the Illinois Basin to Southeastern coal-fired facilities, although it is too early to know the full impact of this arrangement.

Global recession

The analysis underlying the coal transportation assumptions as described above was completed prior to experiencing the full impact of the current global recession on the energy industry. In addition to downward pressure on fuel and steel prices, the recession led to large declines in industrial coal and electricity demand. Coal-fired plants, already faced with a glut of stockpiled coal, saw excess supply further balloon due to relatively mild temperatures throughout 2009 and historically low gas prices that led to some gas-fired facilities displacing more marginal, higher-cost, coal-fired facilities. In the face of declining demand, coal transporters saw movements fall dramatically as contracted tonnage was deferred and contracts were reworked. However, it remains to be seen how, or if, transporters will adjust rates in the face of changing demand dynamics. For example, railroads demonstrated little desire to lower rates in recent contract negotiations even as coal volumes shipped by rail were off 9.3% from year-to-date 2008 levels as of September 12, 2009.

9.4 Coal Exports, Imports, and Non-Electric Sectors Demand

The coal supply curves used in EPA Base Case v.4.10 represent the total steam coal supply in the United States. While the U.S. power sector is the largest consumer of native coal – roughly 93% of mined U.S. coal in 2007 was used in electricity generation – non-electric demand must also be taken into consideration in IPM modeling in order to determine the market clearing price. Furthermore, some coal mined within the U.S. is exported out of the domestic market, and some foreign coal is imported for use in electricity generation, and these changes in the coal supply must also be detailed in the modeling of the coal supply available to coal power plants. The projections for imports, exports, and non-electric sector coal demand are based on EIA's AEO 2010.

In EPA Base Case v.4.10 coal exports and coal-serving residential, commercial and industrial demand are designed to correspond as closely as possible to the projections in AEO 2010 both in terms of the coal supply regions and coal grades that meet this demand. The projections used exclude exports to Canada, as the Canadian market is modeled endogenously within IPM. First, the subset of coal supply regions and coal grades in EPA Base Case v.4.10 are identified that are contained in or overlap geographically with those EIA Coal Market Module (CMM) supply regions and coal grades that are projected as serving exports and non-electric sector demand in AEO 2010. Next, coal for exports and non-electric demand are constrained by CMM supply region and coal grade to meet the levels projected in AEO 2010. These levels are shown in Table 9-24 and Table 9-25. (Since the AEO 2010 time horizon extends to 2035 and EPA Base Case v.4.10 to 2050, the AEO projected levels for 2035 are maintained through 2050.). IPM then endogenously determines which IPM coal supply region(s) and coal grade(s) will be selected to meet the required export or non-electric sector coal demand as part of the cost-minimization coal market equilibrium. Since there are more coal supply regions and coal grades in EPA Base Case v.4.10 than in AEO 2010 the specific regions and coal grades that serve export and non-electric sector demand are not pre-specified but modeled.

Imported coal is assumed to cost 30.81 2007$/Ton, and is only available to plants in the eight demand regions which are eligible to receive imported coal. The eight coal demand regions which may receive imported coal, along with the cost of transporting this coal to the demand regions, are summarized in Table 9-19. The total US imports of steam coal are limited as shown in Table 9-26.

Table 9-24 Coal Exports

Name	2012	2015	2020	2030	2040 -2050
Rocky Mountains - Bituminous Low Sulfur	1.24	0.97	0.45	0.84	1.08
Central Appalachia - Bituminous Medium Sulfur	6.69	7.74	7.4	7.31	6.96
East Interior - Bituminous Medium Sulfur	6.46	4.29	0	0	0
Northern Appalachia - Bituminous Medium Sulfur	4.57	3.02	0	0	0
Wyoming Southern PRB - Subbituminous Low Sulfur	0.03	0.04	0.05	0.09	0.12

Table 9-25 Residential, Commercial, and Industrial Demand

Name	2012	2015	2020	2030	2040 - 2050
East Interior - Bituminous High Sulfur	6.84	7.06	7.1	6.97	6.88
Northern Appalachia - Bituminous High Sulfur	1.12	1.16	1.16	1.14	1.12
West Interior - Bituminous High Sulfur	1.59	1.85	1.99	1.98	1.95
Central Appalachia - Bituminous Low Sulfur	4.8	4.98	5.01	4.89	4.8
Southern Appalachia - Bituminous Low Sulfur	0.21	0.22	0.22	0.21	0.21
Rocky Mountain - Bituminous Low Sulfur	3.78	4.03	4.1	4.06	3.97
Arizona/New Mexico - Bituminous Low Sulfur	0.41	0.43	0.44	0.44	0.43
Central Appalachia - Bituminous Medium Sulfur	13.3	13.84	13.93	13.66	13.42
East Interior - Bituminous Medium Sulfur	0.82	0.84	0.84	0.83	0.82
Northern Appalachia - Bituminous Medium Sulfur	4.02	4.16	4.17	4.05	3.97
Southern Appalachia - Bituminous Medium Sulfur	1.36	1.41	1.42	1.4	1.37
Gulf Lignite - High Sulfur	2.46	2.57	2.59	2.54	2.49
Dakota Lignite - Medium Sulfur	5.26	5.43	5.46	5.36	5.3
Western Montana - Subbituminous Low Sulfur	0.43	0.19	0.03	0	0
Western Wyoming - Subbituminous Low Sulfur	0.92	0.98	1	1	0.98
Wyoming Northern PRB - Subbituminous Low Sulfur	3.85	3.99	4.01	3.94	3.88
Western Wyoming - Subbituminous Medium Sulfur	1.03	1.11	1.14	1.13	1.1
Arizona/New Mexico - Subbituminous Medium Sulfur	0.1	0.11	0.11	0.11	0.11

Table 9-26 Coal Import Limits

	2012	2015	2020	2030	2040 - 2050
Annual Coal Imports Cap (Million Short Tons)	30.0	28.9	36.0	36.2	51.5

Appendix 9-1. Illustrative Example of Wood Mackenzie Costing Procedure Used in Developing EPA's Coal Supply Curves

To further demonstrate the procedures used in preparing Wood Mackenzie's cost tables, a sample was prepared for the Colorado, Green River Basin, 0.81-1.20 lbs. SO_2/MMbtu coals. This region was selected because it contains both surface and underground mines as well as existing (E) and planned new mines (N).

The initial step was to prepare cost models for the selected mines. The mine names have been replaced with mine step designations: E01, E02, E03, N01, N02 and N03. Production and productivity assumptions for the mines have been modified to mask the mines selected for this sample procedure. Cost models were prepared for E01, E02, E03, N02 and N03. N01 was not modeled because it is a proposed replacement for E03 and is expected to have a cost structure very similar to E03. The cost model was run in 2008$ and used to solve for the sales price required to return a 10% DCFROR for the mine.

In the following pages of this appendix individual cost models (in the form of a series of spreadsheets) are provided for mines E01_S, EO2_UG, EO3_UG, NO2_UG, and NO3_UG, Each mine's spreadsheet consists of 4 pages that capture the costs and cash flows for the mines over the 2008 – 2035 time period. The first page in each spreadsheet model provides production and productivity data for the mine. The second page shows its capital requirements. The third page contains a summary of capital expenditures. The fourth page pulls together all costs and cash flows and (in the third row from the top) derives the required sales price on the assumption of a 10% rate of return.

The model results obtained for each mine were then loaded into the "EPA Cost Curve Worksheet," which appears on the last page of this appendix. (The "sales prices ($/ton)" from the mine costing models can be seen in the 11th column ("Cost of Production (2008$)") of the cost curve worksheet. This worksheet also contains EPA's coal region and coal type data as well as Wood Mackenzie region and type codes. (The Wood Mackenzie codes were included to assist in the proper assignment of costs for areas where cost data was prepared and grouped based on Wood Mackenzie codes.) Additional data includes mine names, step names, codes for existing or new mines, mine type (used for western mines), heat content, production rate and reserves.

In conjunction with transferring the costs generated for each mine to the "EPA Cost Curve Worksheet," a number of adjustments were made to support their use in EPA's IPM electric sector model:

(1) There are a number of differences in the values appearing in the 11th column and the corresponding "sales price" values that appeared in the individual mine costing models. For example, it was assumed the N01 production costs would be the same as the mine it is replacing but additional transportation will be required to move the coal to the mine loadout and partial washing would take place. To account for these additional costs $1.00/ton was added to the Cost of Production of E03 to estimate the cost for N01. In the case of N03, it was assumed that additional transportation from the mine mouth to the loadout will be required so an additional $1.00/ton was added to the model results. This adjustment was based on a separate modeling analysis that Wood Mackenzie performed to estimate the cost of production at N03. Because this modeling contained mine specific and proprietary data, it could not be included in this appendix.

(2) Because the mine costing model estimates were prepared in 2008$, the costs were converted (deflated) to constant 2007$, which is the cost basis used in EPA Base Case v.4.10. (This conversion can be seen in the 11th ("Cost of Production (2008$)") and 12th ("Cost of Production (2007$)") columns of the Cost Curve Worksheet.)

(3) In running the individual cost models for new mines, Wood Mackenzie makes certain assumptions regarding the start-up date for the mine. In transferring the costs generated by the cost models to the EPA Cost Curve Worksheet it is assumed that the new mines could be opened by 2012 if demand exists and EPA's IPM model is allowed to determine when the mine will be opened.

(4) Wood Mackenzie has assumed that labor productivity in all Producing Regions except Central Appalachia will increase at a rate of 1% per year. Productivity in Central Appalachia is expected to fall 1% per year. These productivity assumptions affect future Cost of Production estimates. All regions except Central Appalachia were deflated 0.4% per year while it was inflated by 0.4% per year. The 0.4% adjustment is based on the assumption that labor costs on average account for 40% of the Cost of Production. In the EPA Cost Curve Worksheet the productivity adjustments appear in the 13th ("deflator") and 14th ("deflated cost") columns. The 0.4% productivity growth assumption means that in the 4 years between 2008 (the net present value year used in the mine costing spreadsheets) and 2012 (the first model year in EPA's IPM base case) productivity would increase by a factor of 1.02 (shown in the 13th column) and, consequently, the cost shown in the 12th column would have to be divided by this deflator (13th column) to obtain the deflated costs shown in the 14th column

(5) Costs were then rounded by the procedure described above in section 9.3.8 to obtain the "Final Cost" values shown in the 15th column.

Besides the adjustments described above and shown in the cost curve worksheet, other adjustments to costs were made to meet EPA's need for cost and production data out to 2040 and beyond. Wood Mackenzie's cost models are generally run for a maximum of 20 years even though additional, higher cost reserves are known to exist. When production and reserve data were pushed past reserve estimates typically used in the cost models, additional reserves were added and costs were increased. Appendix 9-2 lists the new mines that were included in the 2040 curves. As a quality assurance check, if additional reserves were assigned to any coal region and type, the resulting totals were tested against EIA Reserve Estimate – 2006 (Table 15_06) to insure reserves were not overstated and to establish an upper geologic limit for reserves in any area.

Appendix 9-1 (Cont'd) Illustrative Example

Mine: [illegible]
Production Data

Year	Tons (000)	In-Situ DL Yds (000)	T/S Yds (000)	Total Yds (000)	Ratio	Effective DL % Rehandle	DL Yds (000)	T/S Yds (000)	Total Yds (000)	Ratio
2008	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2009	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2010	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2011	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2012	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2013	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2014	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2015	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2016	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2017	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2018	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2019	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2020	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2021	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2022	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2023	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2024	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2025	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2026	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2027	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2028										
2029										
2030										
2031										
2032										
	50,000	490,000	0	490,000	9.8		539,000	0	539,000	10.8
$/ton										

Mine: **E01_S**
Capital Requirements ($ X 1000)

Capital Contingency: 0%
Miles of Rail spur: 0
Coal Storage: 10000

Year	Acqisition	Develop.	Rail	Facilities	Truck Shovel Initial	Truck Shovel Repl	Dragline Initial	Dragline Repl	Coal Load & Haul Initial	Coal Load & Haul Repl	Miscellaneous Initial	Miscellaneous Repl	Total Initial	Total Repl
2008		0	0	15,878	0		64,680		9,720		16,368		106,646	0
2009					0		0		0		0		0	0
2010					0		0		0		0		0	0
2011					0		0		0		0		0	0
2012					0		0		0		0		0	0
2013					0		0		0		0		0	0
2014					0		0		0		0		0	0
2015					0		0		0		0	16,368	0	16,368
2016					0		0		0		0	0	0	0
2017					0		0		0		0	0	0	0
2018					0	0	0		0	4,082	0	0	0	4,082
2019					0	0	0		0	0	0	0	0	0
2020					0	0	0		0	0	0	0	0	0
2021					0	0	0		0	0	0	0	0	0
2022					0	0	0		0	0	0	16,368	0	16,368
2023					0	0	0		0	0	0	0	0	0
2024					0	0	0		0	0	0	0	0	0
2025					0	0	0		0	0	0	0	0	0
2026					0	0	0		0	0	0	0	0	0
2027					0	0	0		0	0	0	0	0	0
2028														
2029														
2030														
2031														
2032														
	0	0	0	15,878	0	0	64,680	0	9,720	4,082	16,368	32,736	106,646	36,818
	0.00	0.00	0.00	0.32	0.00	0.00	1.29	0.00	0.19	0.08	0.33	0.65	2.13	0.74

Mine: E01_S
Capital Expenditure Summary

Year	Acquisition	Development	Depreciable Assets	Property Tax Base	Depreciation	Working Capital	Total Capital	
2008	0	0	106,646	106,646	14,025	3,993	110,639	
2009	0	0	0	106,646	14,025	0	0	
2010	0	0	0	106,646	14,025	0	0	
2011	0	0	0	106,646	14,025	0	0	
2012	0	0	0	106,646	14,025	0	0	
2013	0	0	0	106,646	14,025	0	0	
2014	0	0	0	106,646	14,025	0	0	
2015	0	0	16,368	106,646	3,397	0	16,368	
2016	0	0	0	106,646	3,397	0	0	
2017	0	0	0	106,646	3,397	0	0	
2018	0	0	4,082	106,646	3,980	0	4,082	
2019	0	0	0	106,646	3,980	0	0	
2020	0	0	0	106,646	3,980	0	0	
2021	0	0	0	106,646	3,980	0	0	
2022	0	0	16,368	106,646	3,980	0	16,368	
2023	0	0	0	106,646	2,921	0	0	
2024	0	0	0	106,646	2,921	0	0	
2025	0	0	0	106,646	2,338	0	0	
2026	0	0	0	106,646	2,338	0	0	
2027	0	0	0	106,646	2,338	-3,993	-3,993	
2028								
2029								
2030								
2031								
2032								
	0	0	143,464		141,126	0	143,464	

Mine: **E01_S**

Required Sales Price

Sales Price ($/ton):	$20.716	Sev. Taxes:	Rate ($/ton)	$0.54
Discount Rate:	10%		Adjustment	0%
Net Present Value:	$0	Property Taxes	Mill Levy (in mills):	44
Cost Contingency Factors:	10%		Assessment rate:	25%
Initial Labor Productivity (t/mh):	9	Income Taxes:	Federal	34%
Average Coal Thickness (ft):	45		State	6%
UMWA (Y or N):	N	Royalty:		12.5%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income) Severance	Black Lung	Recl.	Property	Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
2008	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	110,639	-96,124
2009	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2010	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2011	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2012	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2013	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2014	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2015	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,397	3,625	3,046	4,569	11,591	16,368	-4,777
2016	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,397	3,625	3,046	4,569	11,591	0	11,591
2017	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,397	3,625	3,046	4,569	11,591	0	11,591
2018	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	4,082	7,742
2019	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	0	11,825
2020	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	0	11,825
2021	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	0	11,825
2022	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	16,368	-4,543
2023	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,921	3,625	3,236	4,855	11,401	0	11,401
2024	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,921	3,625	3,236	4,855	11,401	0	11,401
2025	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,338	3,625	3,470	5,205	11,168	0	11,168
2026	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,338	3,625	3,470	5,205	11,168	0	11,168
2027	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,338	3,625	3,470	5,205	11,168	-3,993	15,161
2028																
2029																
2030																
2031																
2032																
	50,000	1,035,785	479,159	129,473	14,040	27,500	17,500	11,394	0	141,126	49,271	40,943	61,414	251,811	143,464	108,347
		20.72	9.58	2.59	0.28	0.55	0.35	0.23	0.00	2.82	0.99	0.82	1.23	5.04	2.87	2.17

Mine: **E02_UG**
Production & Productivity Data

% Washed	70%
Plant Recovery:	70%
Production by Equipment at Full Production	
% Longwall Production:	80%
% CM Production:	20%
% CV Production:	0%

Year	Clean Tons (000)	CV ROM Tons (000)	CM ROM Tons (000)	LW ROM Tons (000)	Total ROM Tons (000)	Overall Recovery %	Haul Distance (miles)
2008	2,000	0	506	2,026	2,532	79%	0
2009	2,000	0	506	2,026	2,532	79%	0
2010	2,000	0	506	2,026	2,532	79%	0
2011	2,000	0	506	2,026	2,532	79%	0
2012	2,000	0	506	2,026	2,532	79%	0
2013	2,000	0	506	2,026	2,532	79%	0
2014	2,000	0	506	2,026	2,532	79%	0
2015	2,000	0	506	2,026	2,532	79%	0
2016	2,000	0	506	2,026	2,532	79%	0
2017	2,000	0	506	2,026	2,532	79%	0
2018	2,000	0	506	2,026	2,532	79%	0
2019	2,000	0	506	2,026	2,532	79%	0
2020	2,000	0	506	2,026	2,532	79%	0
2021	2,000	0	506	2,026	2,532	79%	0
2022	2,000	0	506	2,026	2,532	79%	0
2023	2,000	0	506	2,026	2,532	79%	0
2024	2,000	0	506	2,026	2,532	79%	0
2025	2,000	0	506	2,026	2,532	79%	0
2026	2,000	0	506	2,026	2,532	79%	0
2027	2,000	0	506	2,026	2,532	79%	0
2028	2,000	0	506	2,026	2,532	79%	0
2029							
2030							
2031							
2032							
	42,000		10,634	42,538	53,172	79%	
$/ton							

Mine: E02_UG
Capital Requirements ($ X 1000)

							production
Capital Contingency:	0%	CV Mining Ht:	8.0	Capital Contingency:		-75%	< 500k
Miles of Rail spur:	0	CM Mining Ht:	8.0			-50%	500k<= & < 750k
Coal Storage:	0	LW Mining Ht:	8.0			0%	>750k
Depth to Shafts:	100						
No. of Men/Supply Shafts	1						
No. of Air Shafts	1			Shafts:	if prod < 1000k, 1 M&S + 1 Air		
					if prod > 1000k, 2 M&S + 1 Air		

Year	Acqisition	Exploration & Engineering	Development Labor	Shaft Capital Cost	Surface Facilities & Equip.	Prep Plant	Rail	Conventional Sections Units Required	Conventional Sections Initial $	Conventional Sections Repl $	Continuous Miners Units Required	Continuous Miners Initial $	Continuous Miners Repl $	Longwalls Units Required	Longwalls Initial $	Longwalls Repl $	Fixed U/G Equip. Initial $	Fixed U/G Equip. Repl $	Total Initial $	Total Repl $
2008		1,920	59,940	13,774	11,391	18,990	0	0	0		2	9,000		1	37,500		20,629		173,144	0
2009								0	0		2	0		1	0		0		0	0
2010								0	0		2	0		1	0		0		0	0
2011								0	0		2	0		1	0		0		0	0
2012								0	0		2	0		1	0		0		0	0
2013								0	0		2	0		1	0		0		0	0
2014								0	0		2	0		1	0		0	0	0	0
2015								0	0	0	2	0	9,000	1	0	37,500	0	20,629	0	67,129
2016								0	0	0	2	0	0	1	0	0	0	0	0	0
2017								0	0	0	2	0	0	1	0	0	0	0	0	0
2018								0	0	0	2	0	0	1	0	0	0	0	0	0
2019								0	0	0	2	0	0	1	0	0	0	0	0	0
2020								0	0	0	2	0	0	1	0	0	0	0	0	0
2021								0	0	0	2	0	0	1	0	0	0	0	0	0
2022								0	0	0	2	0	9,000	1	0	37,500	0	20,629	0	67,129
2023								0	0	0	2	0	0	1	0	0	0	0	0	0
2024								0	0	0	2	0	0	1	0	0	0	0	0	0
2025								0	0	0	2	0	0	1	0	0	0	0	0	0
2026								0	0		2	0		1	0		0		0	0
2027								0	0		2	0		1	0		0		0	0
2028								0	0		2	0		1	0		0		0	0
2029																				
2030																				
2031																				
2032																				
	0	1,920	59,940	13,774	11,391	18,990	0		0	0		9,000	18,000		37,500	75,000	20,629	41,257	173,144	134,257
	0.00	0.05	1.43	0.33	0.27		0.00		0.00	0.00		0.21	0.43		0.89	1.79	0.49	0.98	4.12	3.20

Mine: E02_UG
Capital Expenditure Summary

Year	Acquisition	Exploration & Engineering	Depreciable Assets 7 Year Life	Depreciable Assets 15 Year Life	Depreciable Assets Total	Property Tax Base	Depreciation 7 Year Life	Depreciation 15 Year Life	Depreciation Total	Working Capital	Total Capital
2008	0	1,920	67,129	104,095	171,224	171,224	9,590	6,940	16,529	5,789	178,933
2009	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2010	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2011	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2012	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2013	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2014	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2015	0	0	67,129	0	67,129	171,224	9,590	6,940	16,529	0	67,129
2016	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2017	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2018	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2019	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2020	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2021	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2022	0	0	67,129	0	67,129	171,224	9,590	6,940	16,529	0	67,129
2023	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2024	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2025	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2026	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2027	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2028	0	0	0	0	0	171,224	9,590	0	9,590	-5,789	-5,789
2029											
2030											
2031											
2032											
	0	1,920	201,386	104,095	305,481		201,386	104,095	305,481	0	307,401
	0.00	0.05	4.79	2.48	7.27		4.79	2.48	7.27	0.00	7.32

Mine: **E02_UG**
Required Sales Price ($ X 1000)

Sales Price ($/ton):	$36.476
Discount Rate:	10.00%
Net Present Value:	$0
Cost Contingency Factors:	10%
Average Coal Thickness (ft):	6
Tons/Man-hour	6.0
UMWA (Y or N):	Y
Product (Steam or Met)	S

Sev. Taxes:	Rate	$0.27
	Adjustment	100.0%
Prop. Taxes	Tax Rate (in mills)	60
	% of revenue basis for tax	
	Assessment rate:	25.0%
Income Taxes	Federal	34.00%
	State	6.00%
Royalty		8.0%
% of Reserve owned:		0%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income)				Corp G&A, Selling & Acc. Pen.	Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
					Severance	Black Lung	Recl.	Property									
2008	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	1,920	16,529	4,004	1,601	2,402	22,935	177,013	-154,078
2009	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2010	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2011	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2012	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2013	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2014	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2015	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	67,129	-42,657
2016	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2017	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2018	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2019	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2020	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2021	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2022	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	67,129	-42,657
2023	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2024	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2025	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2026	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2027	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2028	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	-5,789	27,647
2029																	
2030																	
2031																	
2032																	
	42,000	1,532,003	729,469	122,560	4,536	46,200	6,300	21,142	46,200	1,920	305,481	105,712	56,993	85,490	496,683	305,481	191,202
		36.48	17.37	2.92	0.11	1.10	0.15	0.50	1.10	0.05	7.27	2.52	1.36	2.04	11.83	7.27	4.55

Mine: **E03_UG**
Production & Productivity Data

% Washed	0%
Plant Recovery:	100%
Production by Equipment at Full Production	
% Longwall Production:	80%
% CM Production:	20%
% CV Production:	0%

Year	Clean Tons (000)	CV ROM Tons (000)	CM ROM Tons (000)	LW ROM Tons (000)	Total ROM Tons (000)	Overall Recovery %	Haul Distance (miles)
2008	9,000	0	1,800	7,200	9,000	100%	0
2009	9,000	0	1,800	7,200	9,000	100%	0
2010	9,000	0	1,800	7,200	9,000	100%	0
2011	9,000	0	1,800	7,200	9,000	100%	0
2012	9,000	0	1,800	7,200	9,000	100%	0
2013	9,000	0	1,800	7,200	9,000	100%	0
2014	9,000	0	1,800	7,200	9,000	100%	0
2015	9,000	0	1,800	7,200	9,000	100%	0
2016	9,000	0	1,800	7,200	9,000	100%	0
2017	9,000	0	1,800	7,200	9,000	100%	0
2018	9,000	0	1,800	7,200	9,000	100%	0
2019	9,000	0	1,800	7,200	9,000	100%	0
2020	9,000	0	1,800	7,200	9,000	100%	0
2021	9,000	0	1,800	7,200	9,000	100%	0
2022	9,000	0	1,800	7,200	9,000	100%	0
2023	9,000	0	1,800	7,200	9,000	100%	0
2024	9,000	0	1,800	7,200	9,000	100%	0
2025	9,000	0	1,800	7,200	9,000	100%	0
2026	9,000	0	1,800	7,200	9,000	100%	0
2027	9,000	0	1,800	7,200	9,000	100%	0
2028	9,000	0	1,800	7,200	9,000	100%	0
2029							
2030							
2031							
2032							
	189,000		37,800	151,200	189,000	100%	
$/ton							

Mine: **E03_UG**
Capital Requirements ($ X 1000)

Capital Contingency:	0%	CV Mining Ht:	10.0	Capital Contingency:		production
Miles of Rail spur:	0	CM Mining Ht:	10.0		-75%	< 500k
Coal Storage:	0	LW Mining Ht:	10.0		-50%	500k<= & < 750k
Depth to Shafts:	100				0%	>750k
No. of Men/Supply Shafts	1					
No. of Air Shafts	1			Shafts:	if prod < 1000k, 1 M&S + 1 Air	
					if prod > 1000k, 2 M&S + 1 Air	

longwall initial 100 million $

Year	Acqisition	Exploration & Engineering	Development Labor	Shaft Capital Cost	Surface Facilities & Equip.	Prep Plant	Rail	Conventional Sections Units Required	Conventional Sections Initial $	Conventional Sections Repl $	Continuous Miners Units Required	Continuous Miners Initial $	Continuous Miners Repl $	Longwalls Units Required	Longwalls Initial $	Longwalls Repl $	Fixed U/G Equip. Initial $	Fixed U/G Equip. Repl $	Total Initial $	Total Repl $
2008		2,590	91,705	9,183	11,878	0	0	0	0		4	12,000		1	100,000		31,562		258,917	0
2009								0	0		4	0		1	0		0		0	0
2010								0	0		4	0		1	0		0		0	0
2011								0	0		4	0		1	0		0		0	0
2012								0	0		4	0		1	0		0		0	0
2013								0	0		4	0		1	0		0		0	0
2014								0	0		4	0		1	0		0	0	0	0
2015								0	0	0	4	0	12,000	1	0	100,000	0	31,562	0	143,562
2016								0	0	0	4	0	0	1	0	0	0	0	0	0
2017								0	0	0	4	0	0	1	0	0	0	0	0	0
2018								0	0	0	4	0	0	1	0	0	0	0	0	0
2019								0	0	0	4	0	0	1	0	0	0	0	0	0
2020								0	0	0	4	0	0	1	0	0	0	0	0	0
2021								0	0	0	4	0	0	1	0	0	0	0	0	0
2022								0	0	0	4	0	12,000	1	0	100,000	0	31,562	0	143,562
2023								0	0	0	4	0	0	1	0	0	0	0	0	0
2024								0	0	0	4	0	0	1	0	0	0	0	0	0
2025								0	0	0	4	0	0	1	0	0	0	0	0	0
2026								0	0		4	0		1	0		0		0	0
2027								0	0		4	0		1	0		0		0	0
2028								0	0		4	0		1	0		0		0	0
2029																				
2030																				
2031																				
2032																				
	0	2,590	91,705	9,183	11,878	0	0		0	0		12,000	24,000		100,000	200,000	31,562	63,124	258,917	287,124
	0.00	0.01	0.49	0.05	0.06		0.00		0.00	0.00		0.06	0.13		0.53	1.06	0.17	0.33	1.37	1.52

Mine: **E03_UG**
Capital Expenditure Summary

Year	Acquisition	Exploration & Engineering	Depreciable Assets 7 Year Life	Depreciable Assets 15 Year Life	Depreciable Assets Total	Property Tax Base	Depreciation 7 Year Life	Depreciation 15 Year Life	Depreciation Total	Working Capital	Total Capital	Year
2008	0	2,590	143,562	112,766	256,327	256,327	20,509	7,518	28,027	19,092	278,009	2008
2009	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2009
2010	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2010
2011	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2011
2012	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2012
2013	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2013
2014	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2014
2015	0	0	143,562	0	143,562	256,327	20,509	7,518	28,027	0	143,562	2015
2016	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2016
2017	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2017
2018	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2018
2019	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2019
2020	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2020
2021	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2021
2022	0	0	143,562	0	143,562	256,327	20,509	7,518	28,027	0	143,562	2022
2023	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2023
2024	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2024
2025	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2025
2026	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2026
2027	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2027
2028	0	0	0	0	0	256,327	20,509	0	20,509	-19,092	-19,092	2028
2029												2029
2030												2030
2031												2031
2032												2032
	0	2,590	430,685	112,766	543,451		430,685	112,766	543,451	0	546,041	
	0.00	0.01	2.28	0.60	2.88		2.28	0.60	2.88	0.00	2.89	

Mine: **E03_UG**

Required Sales Price ($ X 1000)

Sales Price ($/ton):	$21.439	Sev. Taxes:	Rate		$0.27
Discount Rate:	10.00%		Adjustment		100.0%
Net Present Value:	($0)	Prop. Taxes	Tax Rate (in mills)		60
Cost Contingency Factors:	10%		% of revenue basis for tax		
Average Coal Thickness (ft):	10		Assessment rate:		25.0%
Tons/Man-hour	6.9	Income Taxes	Federal		34.00%
UMWA (Y or N):	N		State		6.00%
Product (Steam or Met)	S	Royalty			8.0%
		% of Reserve owned:			0%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income)				Corp G&A, Selling & Acc. Pen.	Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
					Severance	Black Lung	Recl.	Property									
2008	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	2,590	28,027	6,669	2,667	4,001	38,696	275,419	-236,723
2009	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2010	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2011	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2012	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2013	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2014	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2015	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	143,562	-102,793
2016	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2017	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2018	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2019	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2020	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2021	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2022	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	143,562	-102,793
2023	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2024	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2025	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2026	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2027	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2028	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	-19,092	58,357
2029																	
2030																	
2031																	
2032																	
	189,000	4,051,948	2,405,584	324,156	44,226	178,286	28,350	55,917	92,400	2,590	543,451	188,494	75,398	113,096	845,041	543,451	301,590
		21.44	12.73	1.72	0.23	0.94	0.15	0.30	0.49	0.01	2.88	1.00	0.40	0.60	4.47	2.88	1.60

Mine: **N02_UG**
Production & Productivity Data

% Washed	0%
Plant Recovery:	100%
Production by Equipment at Full Production	
% Longwall Production:	80%
% CM Production:	20%
% CV Production:	0%

Year	Clean Tons (000)	CV ROM Tons (000)	CM ROM Tons (000)	LW ROM Tons (000)	Total ROM Tons (000)	Overall Recovery %	Haul Distance (miles)
2011							
2012							
2013							
2014							
2015	500	0	500	0	500	100%	0
2016	3,000	0	600	2,400	3,000	100%	0
2017	5,000	0	1,000	4,000	5,000	100%	0
2018	5,000	0	1,000	4,000	5,000	100%	0
2019	5,000	0	1,000	4,000	5,000	100%	0
2020	5,000	0	1,000	4,000	5,000	100%	0
2021	5,000	0	1,000	4,000	5,000	100%	0
2022	5,000	0	1,000	4,000	5,000	100%	0
2023	5,000	0	1,000	4,000	5,000	100%	0
2024	5,000	0	1,000	4,000	5,000	100%	0
2025	5,000	0	1,000	4,000	5,000	100%	0
2026	5,000	0	1,000	4,000	5,000	100%	0
2027	5,000	0	1,000	4,000	5,000	100%	0
2028	5,000	0	1,000	4,000	5,000	100%	0
2029	5,000	0	1,000	4,000	5,000	100%	0
2030	5,000	0	1,000	4,000	5,000	100%	0
2031	5,000	0	1,000	4,000	5,000	100%	0
2032	5,000	0	1,000	4,000	5,000	100%	0
2033	5,000	0	1,000	4,000	5,000	100%	0
2034	5,000	0	1,000	4,000	5,000	100%	0
2035	5,000	0	1,000	4,000	5,000	100%	0
	98,500		20,100	78,400	98,500	100%	
$/ton							

Mine: **N02_UG**
Capital Requirements ($ X 1000)

Capital Contingency:	0%	CV Mining Ht:	8.0	Capital Contingency:	production	
Miles of Rail spur:	0	CM Mining Ht:	8.0		-75%	< 500k
Coal Storage:	0	LW Mining Ht:	8.0		-50%	500k<= & < 750k
Depth to Shafts:	1000				0%	>750k
No. of Men/Supply Shafts	1					
No. of Air Shafts	1			Shafts:	if prod < 1000k, 1 M&S + 1 Air	
					if prod > 1000k, 2 M&S + 1 Air	

Year	Acqisition	Exploration & Engineering	Development Labor	Shaft Capital Cost	Surface Facilities & Equip.	Prep Plant	Rail	Conventional Sections Units Required	Conventional Sections Initial $	Conventional Sections Repl $	Continuous Miners Units Required	Continuous Miners Initial $	Continuous Miners Repl $	Longwalls Units Required	Longwalls Initial $	Longwalls Repl $	Fixed U/G Equip. Initial $	Fixed U/G Equip. Repl $	Total Initial $	Total Repl $
2011		350	0	0		0	0	0	0		0	0		0	0		1,109		1,459	0
2012		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2013		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2014		1,030	30,085	45,174	6,777	0	0	0	0		0	0		0	0		0		52,981	0
2015								0	0		2	6,000		0	0		1,631		7,631	0
2016								0	0		2	0		1	25,000		6,798		31,798	0
2017								0	0		3	3,000		1	0		816	0	3,816	0
2018								0	0	0	3	0	0	1	0	0	0	1,109	0	1,109
2019								0	0	0	3	0	0	1	0	0	0	0	0	0
2020								0	0	0	3	0	0	1	0	0	0	0	0	0
2021								0	0	0	3	0	0	1	0	0	0	0	0	0
2022								0	0	0	3	0	6,000	1	0	0	0	1,631	0	7,631
2023								0	0	0	3	0	0	1	0	25,000	0	6,798	0	31,798
2024								0	0	0	3	0	3,000	1	0	0	0	816	0	3,816
2025								0	0	0	3	0	0	1	0	0	0	1,109	0	1,109
2026								0	0	0	3	0	0	1	0	0	0	0	0	0
2027								0	0	0	3	0	0	1	0	0	0	0	0	0
2028								0	0	0	3	0	0	1	0	0	0	0	0	0
2029								0	0		3	0		1	0		0		0	0
2030								0	0		3	0		1	0		0		0	0
2031								0	0		3	0		1	0		0		0	0
2032								0	0		3	0		1	0		0		0	0
2033								0	0		3	0		1	0		0		0	0
2034								0	0		3	0		1	0		0		0	0
2035								0	0		3	0		1	0		0		0	0
	0	2,080	30,085	45,174	6,777	0	0		0	0		9,000	9,000		25,000	25,000	10,354	11,463	98,384	45,463
	0.00	0.02	0.31	0.46	0.07		0.00		0.00	0.00		0.09	0.09		0.25	0.25	0.11	0.12	1.00	0.46

Mine: **N02_UG**
Capital Expenditure Summary

Year	Acquisition	Exploration & Engineering	Depreciable Assets 7 Year Life	Depreciable Assets 15 Year Life	Depreciable Assets Total	Property Tax Base	Depreciation 7 Year Life	Depreciation 15 Year Life	Depreciation Total	Working Capital	Total Capital	Year
2011	0	350	1,109	0	1,109	1,109	158	0	158	0	1,459	2011
2012	0	350	0	0	0	1,109	158	0	158	0	350	2012
2013	0	350	0	0	0	1,109	158	0	158	0	350	2013
2014	0	1,030	0	82,036	82,036	53,060	158	5,469	5,627	0	83,066	2014
2015	0	0	7,631	0	7,631	60,691	1,249	5,469	6,718	1,015	8,646	2015
2016	0	0	31,798	0	31,798	92,489	5,791	5,469	11,260	4,840	36,638	2016
2017	0	0	3,816	0	3,816	96,304	6,336	5,469	11,805	3,903	7,719	2017
2018	0	0	1,109	0	1,109	96,304	6,336	5,469	11,805	0	1,109	2018
2019	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2019
2020	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2020
2021	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2021
2022	0	0	7,631	0	7,631	96,304	6,336	5,469	11,805	0	7,631	2022
2023	0	0	31,798	0	31,798	96,304	6,336	5,469	11,805	0	31,798	2023
2024	0	0	3,816	0	3,816	96,304	6,336	5,469	11,805	0	3,816	2024
2025	0	0	1,109	0	1,109	96,304	6,336	5,469	11,805	0	1,109	2025
2026	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2026
2027	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2027
2028	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2028
2029	0	0	0	0	0	96,304	5,246	0	5,246	0	0	2029
2030	0	0	0	0	0	96,304	704	0	704	0	0	2030
2031	0	0	0	0	0	96,304	158	0	158	0	0	2031
2032	0	0	0	0	0	96,304	0	0	0	0	0	2032
2033	0	0	0	0	0	96,304	0	0	0	0	0	2033
2034	0	0	0	0	0	96,304	0	0	0	0	0	2034
2035	0	0	0	0	0	96,304	0	0	0	-9,759	-9,759	2035
	0	2,080	89,816	82,036	171,852		89,816	82,036	171,852	0	173,932	
	0.00	0.02	0.91	0.83	1.74		0.91	0.83	1.74	0.00	1.77	

Mine: **N02_UG**

Required Sales Price ($ X 1000)

Sales Price ($/ton):	$20.007
Discount Rate:	10.00%
Net Present Value:	($0)
Cost Contingency Factors:	10%
Average Coal Thickness (ft):	8
Tons/Man-hour	8.0
UMWA (Y or N):	N
Product (Steam or Met)	S

Sev. Taxes:	Rate	$0.27
	Adjustment	100.0%
Prop. Taxes	Tax Rate (in mills)	60
	% of revenue basis for tax	
	Assessment rate:	25.0%
Income Taxes	Federal	34.00%
	State	6.00%
Royalty		8.0%
% of Reserve owned:		0%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income)				Corp G&A, Selling & Acc. Pen.	Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
					Severance	Black Lung	Recl.	Property									
2011	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	1,109	-1,256
2012	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2013	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2014	0	0	0	0	0	0	0	0	0	1,030	5,627	0	-2,663	-3,994	1,633	82,036	-80,403
2015	500	10,003	6,089	800	0	440	75	138	550	0	6,718	0	-1,923	-2,884	3,834	8,646	-4,812
2016	3,000	60,021	35,131	4,802	486	2,641	450	828	3,300	0	11,260	562	225	337	12,159	36,638	-24,479
2017	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	7,719	11,860
2018	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	1,109	18,470
2019	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2020	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2021	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2022	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	7,631	11,948
2023	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	31,798	-12,218
2024	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	3,816	15,764
2025	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	1,109	18,470
2026	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2027	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2028	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2029	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	5,246	7,363	3,566	5,349	17,957	0	17,957
2030	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	704	7,363	5,383	8,074	16,140	0	16,140
2031	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	158	7,363	5,601	8,401	15,922	0	15,922
2032	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	0	7,363	5,664	8,496	15,859	0	15,859
2033	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	0	7,363	5,664	8,496	15,859	0	15,859
2034	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	0	7,363	5,664	8,496	15,859	0	15,859
2035	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	0	7,363	5,664	8,496	15,859	-9,759	25,617
	98,500	1,970,686	1,153,690	157,655	19,980	86,710	14,775	27,195	87,450	2,080	171,852	110,405	55,557	83,336	365,593	171,852	193,741
		20.01	11.71	1.60	0.20	0.88	0.15	0.28	0.89	0.02	1.74	1.12	0.56	0.85	3.71	1.74	1.97

Mine: **N03_UG**
Production & Productivity Data

% Washed	0%
Plant Recovery:	100%
Production by Equipment at Full Production	
% Longwall Production:	80%
% CM Production:	20%
% CV Production:	0%

Year	Clean Tons (000)	CV ROM Tons (000)	CM ROM Tons (000)	LW ROM Tons (000)	Total ROM Tons (000)	Overall Recovery %	Haul Distance (miles)
2007							
2008							
2009							
2010							
2011		0	0	0	0	#DIV/0!	0
2012		0	0	0	0	#DIV/0!	0
2013		0	0	0	0	#DIV/0!	0
2014	1,000	0	200	800	1,000	100%	0
2015	5,000	0	1,000	4,000	5,000	100%	0
2016	5,000	0	1,000	4,000	5,000	100%	0
2017	5,000	0	1,000	4,000	5,000	100%	0
2018	5,000	0	1,000	4,000	5,000	100%	0
2019	5,000	0	1,000	4,000	5,000	100%	0
2020	5,000	0	1,000	4,000	5,000	100%	0
2021	5,000	0	1,000	4,000	5,000	100%	0
2022	5,000	0	1,000	4,000	5,000	100%	0
2023	5,000	0	1,000	4,000	5,000	100%	0
2024	5,000	0	1,000	4,000	5,000	100%	0
2025	5,000	0	1,000	4,000	5,000	100%	0
2026	5,000	0	1,000	4,000	5,000	100%	0
2027	5,000	0	1,000	4,000	5,000	100%	0
2028	5,000	0	1,000	4,000	5,000	100%	0
2029	5,000	0	1,000	4,000	5,000	100%	0
2030	5,000	0	1,000	4,000	5,000	100%	0
2031	5,000	0	1,000	4,000	5,000	100%	0
	86,000		17,200	68,800	86,000	100%	
$/ton							

Mine: **N03_UG**

Capital Requirements ($ X 1000)

							production
Capital Contingency:	0%	CV Mining Ht:	10.0	Capital Contingency:		-75%	< 500k
Miles of Rail spur:	0	CM Mining Ht:	10.0			-50%	500k<= & < 750k
Coal Storage:	0	LW Mining Ht:	10.0			0%	>750k
Depth to Shafts:	100						
No. of Men/Supply Shafts	1						
No. of Air Shafts	1			Shafts:	if prod < 1000k, 1 M&S + 1 Air		
					if prod > 1000k, 2 M&S + 1 Air		

Year	Acqisition	Exploration & Engineering	Development Labor	Shaft Capital Cost	Surface Facilities & Equip.	Prep Plant	Rail	Conventional Sections Units Required	Conventional Sections Initial $	Conventional Sections Repl $	Continuous Miners Units Required	Continuous Miners Initial $	Continuous Miners Repl $	Longwalls Units Required	Longwalls Initial $	Longwalls Repl $	Fixed U/G Equip. Initial $	Fixed U/G Equip. Repl $	Total Initial $	Total Repl $
2007		350	0	0		0	0	0	0		0	0		0	0		1,109		1,459	0
2008		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2009		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2010		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2011		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2012		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2013		1,530	49,835	9,183	8,412	0	0	0	0		0	0		0	0		0	0	19,124	0
2014								0	0	0	1	3,000	0	1	50,000	0	14,411	1,109	67,411	1,109
2015								0	0	0	3	6,000	0	1	0	0	1,631	0	7,631	0
2016								0	0	0	3	0	0	1	0	0	0	0	0	0
2017								0	0	0	3	0	0	1	0	0	0	0	0	0
2018								0	0	0	3	0	0	1	0	0	0	0	0	0
2019								0	0	0	3	0	0	1	0	0	0	0	0	0
2020								0	0	0	3	0	0	1	0	0	0	0	0	0
2021								0	0	0	3	0	3,000	1	0	50,000	0	15,520	0	68,520
2022								0	0	0	3	0	6,000	1	0	0	0	1,631	0	7,631
2023								0	0	0	3	0	0	1	0	0	0	0	0	0
2024								0	0	0	3	0	0	1	0	0	0	0	0	0
2025								0	0		3	0		1	0		0		0	0
2026								0	0		3	0		1	0		0		0	0
2027								0	0		3	0		1	0		0		0	0
2028								0	0		3	0		1	0		0		0	0
2029								0	0		3	0		1	0		0		0	0
2030								0	0		3	0		1	0		0		0	0
2031								0	0		3	0		1	0		0		0	0
	0	3,630	49,835	9,183	8,412	0	0		0	0		9,000	9,000		50,000	50,000	17,151	18,260	97,375	77,260
	0.00	0.04	0.58	0.11	0.10		0.00		0.00	0.00		0.10	0.10		0.58	0.58	0.20	0.21	1.13	0.90

Mine: **N03_UG**

Capital Expenditure Summary

Year	Acquisition	Exploration & Engineering	Depreciable Assets 7 Year Life	Depreciable Assets 15 Year Life	Depreciable Assets Total	Property Tax Base	Depreciation 7 Year Life	Depreciation 15 Year Life	Depreciation Total	Working Capital	Total Capital
2007	0	350	1,109	0	1,109	1,109	158	0	158	0	1,459
2008	0	350	0	0	0	1,109	158	0	158	0	350
2009	0	350	0	0	0	1,109	158	0	158	0	350
2010	0	350	0	0	0	1,109	158	0	158	0	350
2011	0	350	0	0	0	1,109	158	0	158	0	350
2012	0	350	0	0	0	1,109	158	0	158	0	350
2013	0	1,530	0	67,429	67,429	18,703	158	4,495	4,654	0	68,959
2014	0	0	68,520	0	68,520	86,114	9,789	4,495	14,284	1,745	70,265
2015	0	0	7,631	0	7,631	93,745	10,879	4,495	15,374	6,982	14,613
2016	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2017	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2018	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2019	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2020	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2021	0	0	68,520	0	68,520	93,745	10,879	4,495	15,374	0	68,520
2022	0	0	7,631	0	7,631	93,745	10,879	4,495	15,374	0	7,631
2023	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2024	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2025	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2026	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2027	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2028	0	0	0	0	0	93,745	1,090	0	1,090	0	0
2029	0	0	0	0	0	93,745	0	0	0	0	0
2030	0	0	0	0	0	93,745	0	0	0	0	0
2031	0	0	0	0	0	93,745	0	0	0	-8,727	-8,727
	0	3,630	153,411	67,429	220,841		153,411	67,429	220,841	0	224,471
	0.00	0.04	1.78	0.78	2.57		1.78	0.78	2.57	0.00	2.61

Mine: **N03_UG**

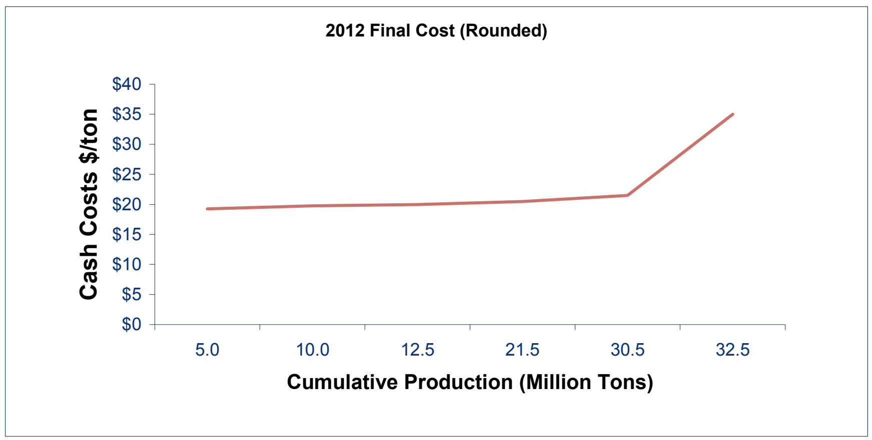
Required Sales Price ($ X 1000)

Sales Price ($/ton):	$19.670	Sev. Taxes:	Rate	$0.27
Discount Rate:	10.00%		Adjustment	100.0%
Net Present Value:	$0	Prop. Taxes	Tax Rate (in mills)	60
Cost Contingency Factors:	10%		% of revenue basis for tax	
Average Coal Thickness (ft):	8		Assessment rate:	25.0%
Tons/Man-hour	10.0	Income Taxes	Federal	34.00%
UMWA (Y or N):	N		State	6.00%
Product (Steam or Met)	S	Royalty		8.0%
		% of Reserve owned:		0%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income)				Corp G&A, Selling & Acc. Pen.	Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
					Severance	Black Lung	Recl.	Property									
2007	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	1,109	-1,256
2008	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2009	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2010	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2011	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2012	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2013	0	0	0	0	0	0	0	0	0	1,530	4,654	0	-2,473	-3,710	943	67,429	-66,486
2014	1,000	19,670	10,473	1,574	0	865	150	271	990	0	14,284	0	-3,575	-5,362	8,921	70,265	-61,344
2015	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	14,613	9,467
2016	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2017	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2018	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2019	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2020	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2021	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	68,520	-44,440
2022	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	7,631	16,449
2023	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2024	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2025	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2026	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2027	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2028	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	1,090	7,238	7,171	10,757	19,085	0	19,085
2029	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	0	7,238	7,607	11,411	18,649	0	18,649
2030	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	0	7,238	7,607	11,411	18,649	0	18,649
2031	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	0	7,238	7,607	11,411	18,649	-8,727	27,377
	86,000	1,691,596	900,654	135,328	17,442	74,430	12,900	23,344	75,790	3,630	220,841	99,690	51,019	76,528	397,059	220,841	176,219
		19.67	10.47	1.57	0.20	0.87	0.15	0.27	0.88	0.04	2.57	1.16	0.59	0.89	4.62	2.57	2.05

Note: Mine cost ($19.67/ton) plus transportation and loadout costs ($1.00/ton) = Total FOB cost ($20.67/ton)

Year	EPA CODES Abbrev	CoalType_Grade		WM CODES CODER	CODEF	Mine	Step Name	Existing or New	Mine Type	Heat Content (MMBtu/Ton)	Cost of Production (2008$/Ton)	Cost of Production (2007$/Ton)	deflator	deflator =- 0.004/yr for all reg deflated cost	Final Cost (Rounded)	2012 Prob. Prod. Coal Production (Million Tons/Year)	Cum Production	2012 Est. Reserves Coal Reserves (Million Tons)
2012	CG	BB		CGH	SCZ	N02	N02	N	U	22.01	$20.01	$19.59	1.02	$19.21	$19.25	5.000	5.000	50.00
2012	CG	BB		CGH	SCZ	N03	N03	N	U	22.01	$20.67	$20.24	1.02	$19.84	$19.75	5.000	10.000	95.00
2012	CG	BB		CGM	SCZ	E01	E01	E	S	22.01	$20.72	$20.29	1.02	$19.89	$20.00	2.500	12.500	20.00
2012	CG	BB		CGH	SCZ	E03	E03	E	U	22.01	$21.44	$20.99	1.02	$20.58	$20.50	9.000	21.500	80.00
2012	CG	BB		CGH	SCZ	N01	N01	N	U	22.01	$22.44	$21.97	1.02	$21.54	$21.50	9.000	30.500	70.00
2012	CG	BB		CGM	SCZ	E02	E02	E	U	22.01	$36.48	$35.72	1.02	$35.01	$35.00	2.000	32.500	20.00



Appendix 9-2 New Mines Included in 2040 Curves

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	AL	BB	N01	24.82	$39.50	4	13
2040	AL	BB	N02	24.82	$42.00	0	25
2040	AL	BB	N03	24.82	$44.50	4	50
2040	AL	BB	N04	24.82	$47.00	0	50
2040	AL	BD	N01	24	$47.00	2	49
2040	AL	BD	N02	24	$58.00	2	50
2040	AL	BD	N03	24	$70.00	2	50
2040	AL	BD	N04	24	$82.00	2	50
2040	AL	BE	N01	23.82	$63.00	0.5	121
2040	AL	BE	N02	23.82	$69.00	0.5	115
2040	AL	BE	N03	23.82	$75.00	0.5	115
2040	AL	BE	N04	23.82	$82.00	0.5	98
2040	AZ	BB	N01	24.64	$16.75	5	450
2040	CG	BA	N01	21.49	$18.25	12	70
2040	CG	BA	N02	21.49	$29.00	1	40
2040	CG	BA	N03	21.49	$23.00	3	350
2040	CG	BB	N01	22.01	$19.25	9	70
2040	CG	BB	N02	22.01	$16.75	5	50
2040	CG	BB	N03	22.01	$17.75	5	95
2040	CR	BA	N02	25.5	$27.00	3	60
2040	CR	BD	N01	22.2	$27.00	0.3	10
2040	CU	BB	N01	23.22	$19.25	8	100
2040	IL	BE	N01	23	$32.50	1	55
2040	IL	BE	N02	23	$32.00	1	15
2040	IL	BE	N03	23	$33.50	1	15
2040	IL	BE	N04	23	$35.00	1	15
2040	IL	BE	N05	23	$37.00	1	15
2040	IL	BE	N06	23	$38.50	1	15
2040	IL	BE	N07	23	$40.50	1	15
2040	IL	BE	N08	23	$42.00	1	15
2040	IL	BE	N09	23	$44.00	1	15
2040	IL	BE	N10	23	$45.50	1	15
2040	IL	BE	N11	23	$47.00	1	15
2040	IL	BE	N12	23	$49.00	1	15
2040	IL	BE	N13	23	$51.00	1	15
2040	IL	BE	N14	23	$52.00	1	15
2040	IL	BE	N15	23	$86.00	1	15
2040	IL	BG	N01	23.01	$24.00	5	398
2040	IL	BG	N02	23.01	$27.00	2.5	9.6
2040	IL	BG	N03	23.01	$28.50	3	38
2040	IL	BG	N04	23.01	$37.50	4	130
2040	IL	BG	N05	23.01	$46.00	0.5	8
2040	IL	BG	N06	23.01	$28.50	4	200
2040	IL	BG	N07	23.01	$32.50	4	200

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	IL	BG	N08	23.01	$37.00	4	200
2040	IL	BG	N09	23.01	$41.00	4	200
2040	IL	BG	N10	23.01	$45.50	4	200
2040	IL	BG	N11	23.01	$54.00	4	200
2040	IL	BG	N12	23.01	$86.00	4	200
2040	IL	BH	N01	22.19	$24.00	5	177.4
2040	IL	BH	N02	22.19	$24.00	5	253.2
2040	IL	BH	N03	22.19	$24.00	5	221.9
2040	IL	BH	N04	22.19	$24.50	3.7	107.5
2040	IL	BH	N05	22.19	$24.00	3	70
2040	IL	BH	N06	22.19	$24.00	3	60
2040	IL	BH	N07	22.19	$27.50	7.8	460
2040	IL	BH	N08	22.19	$29.00	0.5	2
2040	IL	BH	N09	22.19	$31.50	2.2	125
2040	IL	BH	N10	22.19	$35.00	0.2	3
2040	IL	BH	N11	22.19	$38.50	1.9	37.8
2040	IL	BH	N12	22.19	$48.50	0.8	20
2040	IL	BH	N13	22.19	$53.00	0.5	4
2040	IL	BH	N14	22.19	$86.00	5	250
2040	IN	BD	N01	22.62	$30.00	0.5	10
2040	IN	BD	N02	22.62	$32.00	0.5	10
2040	IN	BD	N03	22.62	$34.50	0.5	10
2040	IN	BD	N04	22.62	$86.00	0.5	10
2040	IN	BE	N01	23.43	$24.00	0.1	0.5
2040	IN	BE	N02	23.43	$34.50	1	15
2040	IN	BE	N03	23.43	$37.00	1	26
2040	IN	BE	N04	23.43	$86.00	1	15
2040	IN	BG	N01	23.37	$27.50	1.5	30
2040	IN	BG	N02	23.37	$30.50	1.5	30
2040	IN	BG	N03	23.37	$33.00	0.5	6
2040	IN	BG	N04	23.37	$35.00	1.6	9.5
2040	IN	BG	N05	23.37	$38.00	1	418.1
2040	IN	BG	N06	23.37	$84.00	1	5
2040	IN	BH	N01	23.41	$31.00	1.5	60
2040	IN	BH	N02	23.41	$34.00	0.2	3
2040	IN	BH	N03	23.41	$49.50	0.8	11
2040	IN	BH	N04	23.41	$28.50	1.5	60
2040	IN	BH	N05	23.41	$29.50	1.5	60
2040	IN	BH	N06	23.41	$30.00	1.5	60
2040	IN	BH	N07	23.41	$31.00	1.5	60
2040	IN	BH	N08	23.41	$32.00	1.5	60
2040	IN	BH	N09	23.41	$33.00	1.5	60
2040	IN	BH	N10	23.41	$34.00	1.5	60
2040	IN	BH	N11	23.41	$35.00	1.5	60
2040	IN	BH	N12	23.41	$36.00	1.5	60

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	IN	BH	N13	23.41	$37.00	1.5	60
2040	IN	BH	N14	23.41	$38.00	1.5	60
2040	IN	BH	N15	23.41	$39.00	1.5	60
2040	IN	BH	N16	23.41	$40.00	1.5	60
2040	IN	BH	N17	23.41	$40.50	1.5	60
2040	IN	BH	N18	23.41	$41.50	1.5	60
2040	IN	BH	N19	23.41	$42.50	1.5	60
2040	IN	BH	N20	23.41	$43.50	1.5	60
2040	IN	BH	N21	23.41	$44.50	1.5	60
2040	IN	BH	N22	23.41	$45.50	1.5	60
2040	IN	BH	N23	23.41	$46.50	1.5	60
2040	IN	BH	N24	23.41	$47.50	1.5	60
2040	IN	BH	N25	23.41	$48.50	1.5	60
2040	IN	BH	N26	23.41	$49.50	1.5	60
2040	IN	BH	N27	23.41	$50.00	1.5	60
2040	IN	BH	N28	23.41	$51.00	1.5	60
2040	IN	BH	N29	23.41	$52.00	1.5	60
2040	IN	BH	N30	23.41	$53.00	1.5	60
2040	IN	BH	N31	23.41	$54.00	1.5	60
2040	IN	BH	N32	23.41	$86.00	1.5	60
2040	KE	BA	N01	25.32	$68.00	0.3	11.9
2040	KE	BA	N02	25.32	$88.00	0.3	15
2040	KE	BA	N03	25.32	$108.00	0.3	15
2040	KE	BA	N04	25.32	$128.00	0.3	15
2040	KE	BB	N01	25.79	$87.00	0.5	71.1
2040	KE	BB	N02	25.79	$99.00	0.5	80
2040	KE	BB	N03	25.79	$111.00	0.5	80
2040	KE	BB	N04	25.79	$123.00	0.5	80
2040	KE	BD	N01	25.33	$74.00	4.1	192.7
2040	KE	BD	N02	25.33	$87.00	3	170
2040	KE	BD	N03	25.33	$100.00	2	180
2040	KE	BD	N04	25.33	$114.00	1	152
2040	KE	BE	N01	25.14	$71.00	4.1	351.8
2040	KE	BE	N02	25.14	$91.00	3	320
2040	KE	BE	N03	25.14	$111.00	2	150
2040	KE	BE	N04	25.14	$130.00	1	145
2040	KE	BG	N01	24.09	$57.00	0.3	4
2040	KE	BG	N02	24.09	$87.00	0.3	4
2040	KE	BG	N03	24.09	$117.00	0.3	4
2040	KE	BG	N04	24.09	$148.00	0.3	4
2040	KS	BG	N01	25.32	$36.50	0.1	1.2
2040	KS	BG	N02	25.32	$44.50	0.1	1.2
2040	KS	BG	N03	25.32	$52.00	0.1	1.2
2040	KS	BG	N04	25.32	$59.00	0.1	1.2
2040	KS	BG	N05	25.32	$67.00	0.1	1.2

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	KS	BG	N06	25.32	$86.00	0.1	1.2
2040	KW	BD	N01	24.23	$59.00	0.7	10
2040	KW	BD	N02	24.23	$67.00	0.5	105
2040	KW	BD	N03	24.23	$86.00	0.5	105
2040	KW	BE	N01	24.45	$30.50	2	300
2040	KW	BE	N02	24.45	$33.50	0.5	30
2040	KW	BE	N03	24.45	$34.00	0.5	30
2040	KW	BE	N04	24.45	$34.50	0.5	30
2040	KW	BE	N05	24.45	$35.00	0.5	30
2040	KW	BE	N06	24.45	$35.50	0.5	30
2040	KW	BE	N07	24.45	$36.50	0.5	30
2040	KW	BE	N08	24.45	$37.00	0.5	30
2040	KW	BE	N09	24.45	$37.50	0.5	30
2040	KW	BE	N10	24.45	$38.00	0.5	30
2040	KW	BE	N11	24.45	$38.50	0.5	30
2040	KW	BE	N12	24.45	$39.00	0.5	30
2040	KW	BE	N13	24.45	$39.50	0.5	30
2040	KW	BE	N14	24.45	$40.00	0.5	30
2040	KW	BE	N15	24.45	$40.50	0.5	30
2040	KW	BE	N16	24.45	$41.50	0.5	30
2040	KW	BE	N17	24.45	$42.00	0.5	30
2040	KW	BE	N18	24.45	$42.50	0.5	30
2040	KW	BE	N19	24.45	$43.00	0.5	30
2040	KW	BE	N20	24.45	$86.00	0.5	30
2040	KW	BG	N01	23.93	$26.00	3	24.8
2040	KW	BG	N02	23.93	$30.00	3	195
2040	KW	BG	N03	23.93	$32.00	3	156.8
2040	KW	BG	N04	23.93	$36.50	4	104.5
2040	KW	BG	N05	23.93	$37.00	2	20
2040	KW	BG	N06	23.93	$50.00	3	180
2040	KW	BG	N07	23.93	$86.00	3	180
2040	KW	BH	N01	22.84	$29.50	5	17
2040	KW	BH	N02	22.84	$32.00	1	4
2040	KW	BH	N03	22.84	$34.00	2	22
2040	KW	BH	N04	22.84	$38.00	1	7.8
2040	KW	BH	N05	22.84	$53.00	1	30
2040	KW	BH	N06	22.84	$53.00	2	240
2040	KW	BH	N07	22.84	$53.00	2	240
2040	KW	BH	N08	22.84	$53.00	2	240
2040	KW	BH	N09	22.84	$53.00	2	240
2040	KW	BH	N10	22.84	$53.00	2	240
2040	KW	BH	N11	22.84	$54.00	2	240
2040	KW	BH	N12	22.84	$86.00	2	240
2040	LA	LE	N01	14.09	$19.00	2	75
2040	LA	LE	N02	14.09	$43.00	2	75

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	MD	BB	N01	24.64	$71.00	0.3	5
2040	MD	BB	N02	24.64	$76.00	0.3	5
2040	MD	BB	N03	24.64	$80.00	0.3	5
2040	MD	BB	N04	24.64	$85.00	0.3	5
2040	MD	BD	N01	26.32	$65.00	0.7	2.5
2040	MD	BD	N02	26.32	$70.00	0.7	7.5
2040	MD	BD	N03	26.32	$76.00	0.7	8
2040	MD	BD	N04	26.32	$85.00	0.7	7
2040	MD	BE	N01	24.85	$44.00	0.3	3
2040	MD	BE	N02	24.85	$58.00	0.3	3
2040	MD	BE	N03	24.85	$73.00	0.3	3
2040	MD	BE	N04	24.85	$88.00	0.3	3
2040	MD	BG	N01	23.26	$55.00	0.4	15
2040	MD	BG	N02	23.26	$62.00	0.4	15
2040	MD	BG	N03	23.26	$69.00	0.4	15
2040	MD	BG	N04	23.26	$78.00	0.4	15
2040	ME	LD	N01	13	$11.75	15	550
2040	ME	LD	N02	13.55	$12.50	15	550
2040	ME	LD	N03	13.85	$14.75	15	400
2040	ME	LD	N04	13.1	$15.00	1	50
2040	ME	LD	N05	14.2	$15.50	15	3500
2040	ME	LD	N06	13	$16.00	15	970
2040	ME	LD	N07	13.4	$17.00	15	1400
2040	ME	LD	N08	13.3	$17.00	15	455
2040	ME	LD	N09	13.2	$24.00	10	215
2040	MP	SA	N01	18.9	$13.75	15	450
2040	MP	SA	N02	18.9	$14.75	15	450
2040	MP	SA	N03	18.9	$17.00	15	450
2040	MP	SD	N01	17.23	$14.25	15	450
2040	MP	SD	N02	17.23	$13.00	15	450
2040	MP	SD	N03	17.23	$15.25	15	450
2040	MS	LE	N01	12.8	$15.75	3	96
2040	MS	LE	N02	12.8	$43.00	1	40
2040	MT	BB	N01	21	$23.50	5	450
2040	ND	LD	N01	13.7	$15.75	18	500
2040	ND	LD	N02	13.7	$15.25	9	565
2040	ND	LD	N03	13.7	$13.75	1	512
2040	ND	LE	N01	13.46	$13.75	6	589
2040	ND	LE	N02	13.46	$17.00	4	500
2040	ND	LE	N03	13.46	$26.50	2	51
2040	NS	BB	N01	26.4	$43.00	0.6	22
2040	NS	BD	N01	22	$23.00	0.4	16
2040	NS	BD	N02	22	$43.00	0.4	20
2040	NS	BE	N01	17	$14.25	6	180
2040	NS	BE	N02	22	$43.00	0.4	20

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	OH	BB	N01	24.68	$76.00	1	50
2040	OH	BB	N02	24.68	$83.00	1	50
2040	OH	BB	N03	24.68	$91.00	1	50
2040	OH	BB	N04	24.68	$100.00	1	50
2040	OH	BD	N01	25.55	$63.00	0.3	94
2040	OH	BD	N02	25.55	$69.00	0.3	100
2040	OH	BD	N03	25.55	$75.00	0.3	100
2040	OH	BD	N04	25.55	$82.00	0.3	100
2040	OH	BE	N01	25.24	$57.00	0.5	208
2040	OH	BE	N02	25.24	$69.00	0.5	210
2040	OH	BE	N03	25.24	$81.00	0.5	210
2040	OH	BE	N04	25.24	$94.00	0.5	230
2040	OH	BG	N01	24.34	$49.00	4	446
2040	OH	BG	N02	24.34	$60.00	4	450
2040	OH	BG	N03	24.34	$70.00	4	450
2040	OH	BG	N04	24.34	$82.00	4	450
2040	OH	BH	N01	23.92	$50.00	4	500
2040	OH	BH	N02	23.92	$60.00	4	500
2040	OH	BH	N03	23.92	$72.00	4	500
2040	OH	BH	N04	23.92	$86.00	4	500
2040	OK	BE	N01	22.15	$45.00	0.3	3.6
2040	OK	BE	N02	22.15	$48.00	0.3	3.6
2040	OK	BE	N03	22.15	$51.00	0.3	3.6
2040	OK	BE	N04	22.15	$55.00	0.3	3.6
2040	OK	BE	N05	22.15	$86.00	0.3	3.6
2040	PC	BD	N01	25.06	$64.00	0.5	7.6
2040	PC	BD	N02	25.06	$73.00	0.5	5
2040	PC	BD	N03	25.06	$83.00	0.5	5
2040	PC	BD	N04	25.06	$94.00	0.5	5
2040	PC	BE	N01	25.66	$39.50	1.5	15
2040	PC	BE	N02	25.66	$54.00	1.5	15
2040	PC	BE	N03	25.66	$69.00	1.5	15
2040	PC	BE	N04	25.66	$84.00	1.5	15
2040	PC	BG	N01	25.33	$51.00	1	22
2040	PC	BG	N02	25.33	$60.00	1	25
2040	PC	BG	N03	25.33	$68.00	1	20
2040	PC	BG	N04	25.33	$77.00	1	20
2040	PC	BH	N01	23.39	$51.00	0.5	10
2040	PC	BH	N02	23.39	$60.00	0.5	10
2040	PC	BH	N03	23.39	$68.00	0.5	10
2040	PC	BH	N04	23.39	$77.00	0.5	10
2040	PW	BD	N01	24.26	$38.50	0.8	122
2040	PW	BD	N02	24.26	$43.00	0.8	126
2040	PW	BD	N03	24.26	$47.00	0.8	130
2040	PW	BD	N04	24.26	$51.00	0.8	134

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	PW	BE	N01	26.22	$37.00	2	744
2040	PW	BE	N02	26.22	$40.50	2	784
2040	PW	BE	N03	26.22	$44.00	2	824
2040	PW	BE	N04	26.22	$46.00	2	864
2040	PW	BG	N01	25.86	$37.00	5	567
2040	PW	BG	N02	25.86	$39.50	5	667
2040	PW	BG	N03	25.86	$42.50	5	767
2040	PW	BG	N04	25.86	$64.00	1	767
2040	TN	BB	N01	24.18	$101.00	0.3	3.8
2040	TN	BB	N02	24.18	$106.00	0.3	3.8
2040	TN	BB	N03	24.18	$112.00	0.3	3.8
2040	TN	BB	N04	24.18	$118.00	0.3	3.8
2040	TN	BD	N01	23.91	$101.00	0.3	4.5
2040	TN	BD	N02	23.91	$104.00	0.3	4.5
2040	TN	BD	N03	23.91	$107.00	0.3	4.5
2040	TN	BD	N04	23.91	$110.00	0.3	4.2
2040	TN	BE	N01	26.75	$85.00	0.3	6.3
2040	TN	BE	N02	26.75	$93.00	0.3	6
2040	TN	BE	N03	26.75	$101.00	0.3	6
2040	TN	BE	N04	26.75	$110.00	0.3	6
2040	TX	LE	N01	13.22	$11.50	11	219
2040	TX	LE	N02	13.22	$14.75	4	150
2040	TX	LE	N03	13.22	$15.75	6	127
2040	TX	LE	N04	13.22	$15.25	7	114
2040	UT	BA	N01	23.68	$20.00	1	10
2040	UT	BA	N02	23.68	$24.50	4	80
2040	UT	BA	N03	23.68	$24.50	4	25
2040	UT	BB	N01	23.23	$25.50	4	50
2040	UT	BB	N02	23.23	$21.50	2	22
2040	UT	BD	N01	23.05	$24.00	4	45
2040	UT	BD	N02	23.05	$41.00	3	50
2040	UT	BE	N01	25.06	$28.50	2	40
2040	VA	BA	N01	22.7	$103.00	0.3	44.4
2040	VA	BA	N02	22.7	$108.00	0.3	40
2040	VA	BA	N03	22.7	$115.00	0.3	40
2040	VA	BA	N04	22.7	$121.00	0.3	39
2040	VA	BB	N01	25.97	$94.00	0.8	87.2
2040	VA	BB	N02	25.97	$103.00	0.8	85
2040	VA	BB	N03	25.97	$112.00	0.8	85
2040	VA	BB	N04	25.97	$120.00	0.8	84
2040	VA	BD	N01	25.76	$85.00	1.1	68.4
2040	VA	BD	N02	25.76	$94.00	0.8	50
2040	VA	BD	N03	25.76	$103.00	0.8	50
2040	VA	BD	N04	25.76	$112.00	0.8	42
2040	VA	BE	N01	26.03	$68.00	0.5	40.6

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	VA	BE	N02	26.03	$78.00	0.5	26
2040	VA	BE	N03	26.03	$89.00	0.5	26
2040	VA	BE	N04	26.03	$112.00	0.5	26
2040	WG	BB	N01	21.67	$24.50	0.5	15
2040	WG	BB	N02	21.67	$23.50	6	190
2040	WG	BB	N03	21.67	$22.50	3	55
2040	WG	SD	N01	18.5	$19.75	1	13
2040	WL	SB	N01	17.15	$17.75	15	450
2040	WL	SB	N02	17.15	$10.75	15	450
2040	WL	SB	N03	17.15	$11.75	15	450
2040	WL	SB	N04	17.15	$13.00	15	450
2040	WN	BD	N01	25.01	$45.50	0.4	1.6
2040	WN	BD	N02	25.01	$65.00	0.4	2
2040	WN	BD	N03	25.01	$85.00	0.4	2
2040	WN	BD	N04	25.01	$104.00	0.4	2
2040	WN	BE	N01	25.67	$29.00	2	40
2040	WN	BE	N02	25.67	$49.00	2	40
2040	WN	BE	N03	25.67	$69.00	2	40
2040	WN	BE	N04	25.67	$89.00	2	40
2040	WN	BG	N01	26.03	$32.50	6.5	600
2040	WN	BG	N02	26.03	$48.00	5	600
2040	WN	BG	N03	26.03	$64.00	5	600
2040	WN	BG	N04	26.03	$80.00	5	600
2040	WN	BH	N01	25.15	$34.00	5	125
2040	WN	BH	N02	25.15	$53.00	5	125
2040	WN	BH	N03	25.15	$72.00	5	125
2040	WN	BH	N04	25.15	$91.00	5	75
2040	WS	BA	N01	26.2	$98.00	0.3	4.7
2040	WS	BA	N02	26.2	$107.00	0.3	4.7
2040	WS	BA	N03	26.2	$112.00	0.3	4.7
2040	WS	BA	N04	26.2	$122.00	0.3	4.6
2040	WS	BB	N01	24.73	$90.00	0.5	106.8
2040	WS	BB	N02	24.73	$107.00	0.5	100
2040	WS	BB	N03	24.73	$114.00	0.5	100
2040	WS	BB	N04	24.73	$122.00	0.5	100
2040	WS	BD	N01	24.64	$82.00	1.5	384.8
2040	WS	BD	N02	24.64	$89.00	1.5	333
2040	WS	BD	N03	24.64	$120.00	1.5	333
2040	WS	BD	N04	24.64	$147.00	1.5	333
2040	WS	BE	N01	24.38	$69.00	1.4	420.7
2040	WS	BE	N02	24.38	$84.00	1.3	420
2040	WS	BE	N03	24.38	$99.00	1.3	420
2040	WS	BE	N04	24.38	$113.00	1.3	420
2040	WS	BG	N01	25.64	$69.00	0.8	80
2040	WS	BG	N02	25.64	$80.00	0.8	79

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	WS	BG	N03	25.64	$92.00	0.8	79
2040	WS	BG	N04	25.64	$104.00	0.8	80

Appendix 9-3 Coal Transportation Matrix in EPA Base Case v.4.10

This is a small excerpt of the data in Appendix 9-3. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html

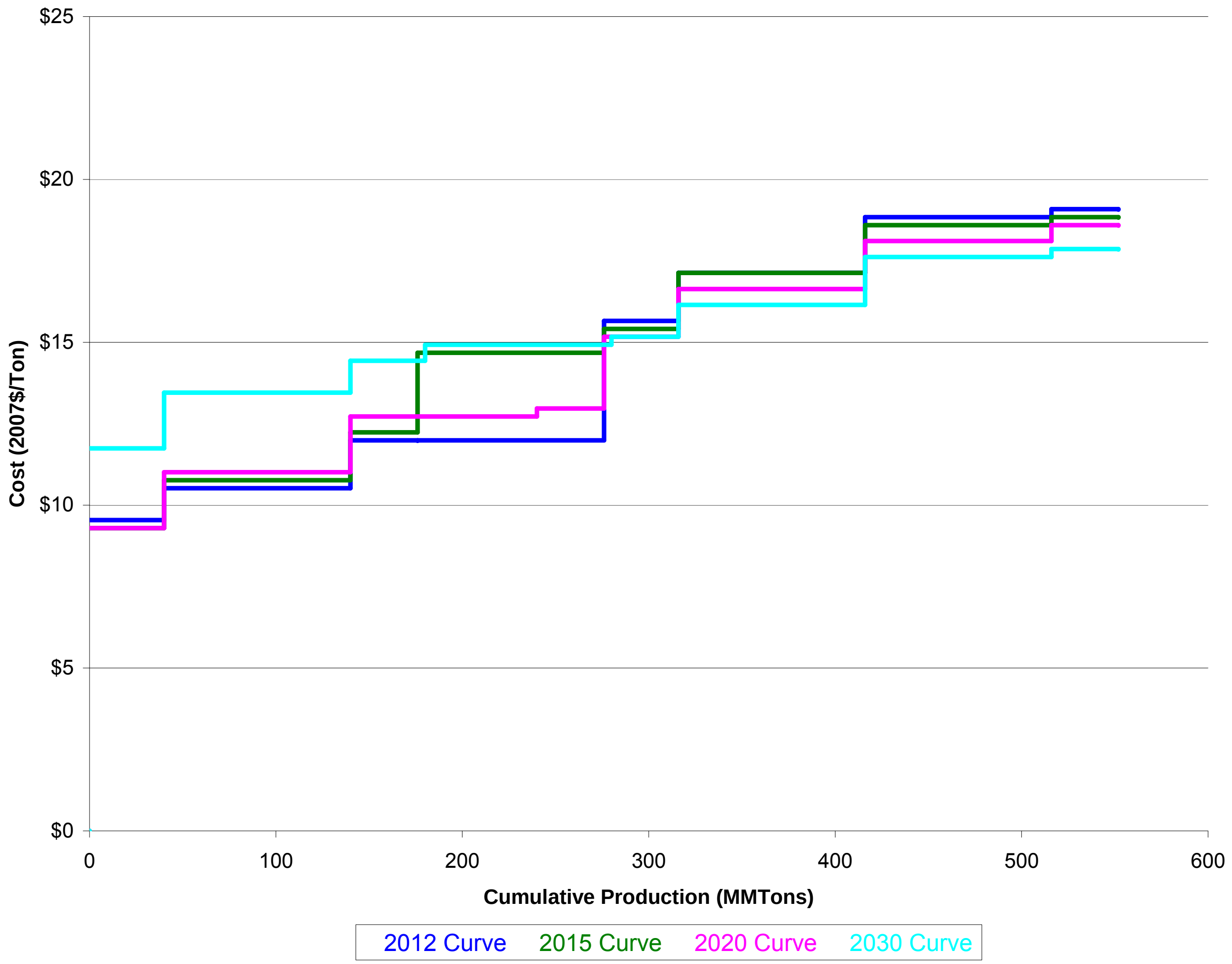
Coal Supply Region – Description	Coal Demand Region	Coal Demand Region Description	Total Cost (2007$/Ton)	Escalation/ Year (2012-2025)	Escalation/ Year (2026-2054)
Arizona	AMM1	AMMM_High-Cost Competitive_Mine Mouth_Rail	1.13	1	1
New Mexico, San Juan	AMM1	AMMM_High-Cost Competitive_Mine Mouth_Rail	1.13	1	1
West Virginia, North	NAI1	NAIN_High-Cost Competitive_Mine Mouth_Rail	1.13	1	1
Wyoming, Powder River Basin (8400)	NAI1	NAIN_High-Cost Competitive_Mine Mouth_Rail	36.93	1	1.0021
Louisiana	TXL1	TXLG_High-Cost Competitive_Mine Mouth_Rail	1.13	1	1
Wyoming, Powder River Basin (8400)	TXL1	TXLG_High-Cost Competitive_Mine Mouth_Rail	24.58	1	1.0021
Wyoming, Powder River Basin (8800)	NAI1	NAIN_High-Cost Competitive_Mine Mouth_Rail	37.3	1	1.0021
Wyoming, Powder River Basin (8800)	TXL1	TXLG_High-Cost Competitive_Mine Mouth_Rail	22.63	1	1.0021
Montana, East	DAL1	DALG_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	4.83	1	1.0042
Wyoming, Powder River Basin (8400)	DAL1	DALG_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	10.79	1	1.002
Wyoming, Powder River Basin (8400)	PRB1	PRB_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	2.21	1	1.0011
Wyoming, Powder River Basin (8400)	WYG1	WYGR_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	2.21	1	1.0011
Wyoming, Powder River Basin (8800)	DAL1	DALG_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	11.23	1	1.002
Wyoming, Powder River Basin (8800)	PRB1	PRB_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	1.13	1	1
Alabama	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	0	1	1
Colorado, Green River	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	33.86	1	1.0022
Colorado, Uinta	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	39.76	1	1.0022
Illinois	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	25.73	1	1.0022
Indiana	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	23.32	1	1.0022
Kentucky East	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	26.57	1	1.0022

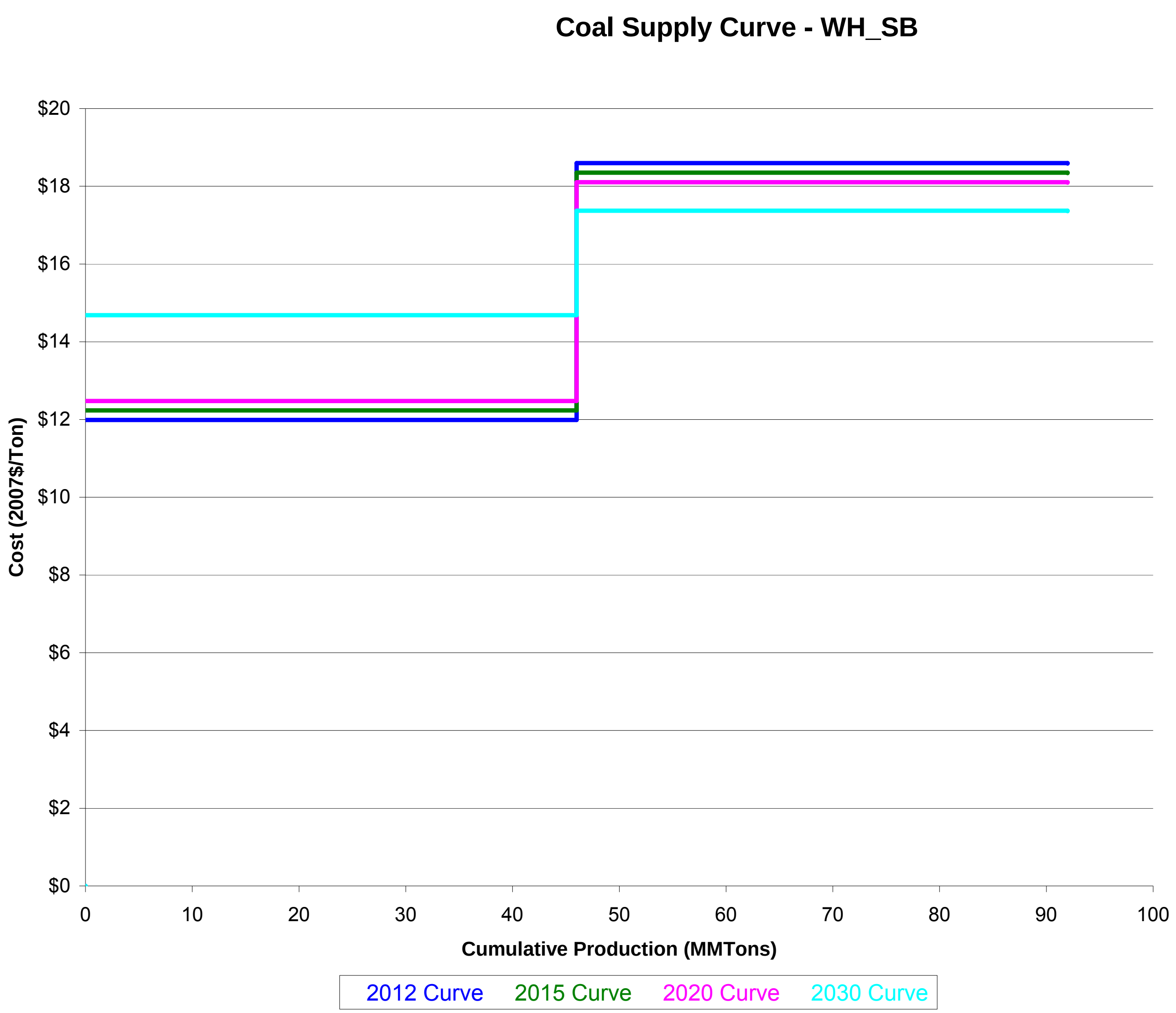
Appendix 9-4 Coal Supply Curves in EPA Base Case v.4.10

This is a small excerpt of the data in Appendix 9-4. The complete data set in spreadsheet format and complete set of graphs can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html

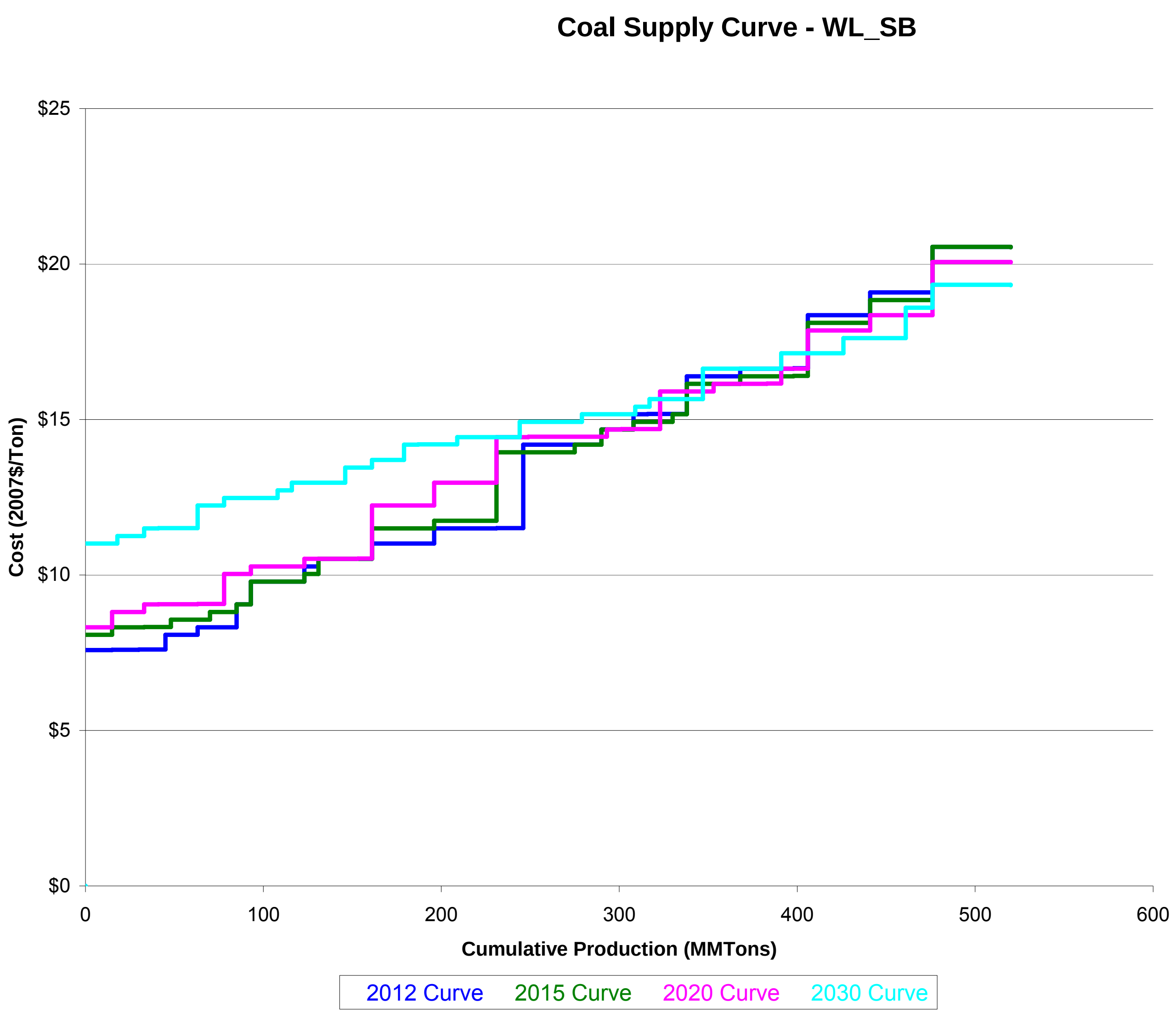
Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2012	AL	BB	E01	24.82	43.1	1.0	111
2012	AL	BB	N01	24.82	44.5	4.0	13
2012	AL	BB	N02	24.82	47.0	0.0	25
2012	AL	BB	E02	24.82	48.9	0.9	51
2012	AL	BB	E03	24.82	49.9	5.6	73
2012	AL	BB	N03	24.82	49.9	4.0	50
2012	AL	BB	E04	24.82	50.9	1.0	5
2012	AL	BB	N04	24.82	52.9	0.0	50
2012	AL	BB	E05	24.82	53.8	0.8	22
2012	AL	BD	E01	24	43.1	0.4	233
2012	AL	BD	E02	24	44.5	0.3	9
2012	AL	BD	E03	24	48.9	0.4	16
2012	AL	BD	E04	24	52.9	0.9	10
2012	AL	BD	N01	24	52.9	2.0	49
2012	AL	BD	E05	24	53.8	0.3	1
2012	AL	BD	E06	24	56.8	0.7	26
2012	AL	BD	E07	24	64.6	0.4	24
2012	AL	BD	N02	24	65.6	2.0	50
2012	AL	BD	E08	24	73.4	0.1	6
2012	AL	BD	N03	24	78.3	2.0	50
2012	AL	BD	E09	24	85.1	0.5	26
2012	AL	BD	N04	24	92.0	2.0	50
2012	AL	BE	E01	23.82	36.2	1.8	93
2012	AL	BE	E02	23.82	43.1	0.4	14
2012	AL	BE	E03	23.82	45.5	0.1	0
2012	AL	BE	E04	23.82	50.9	0.4	10
2012	AL	BE	E05	23.82	54.8	0.9	16
2012	AL	BE	E06	23.82	62.6	0.2	5
2012	AL	BE	N01	23.82	70.5	0.5	121

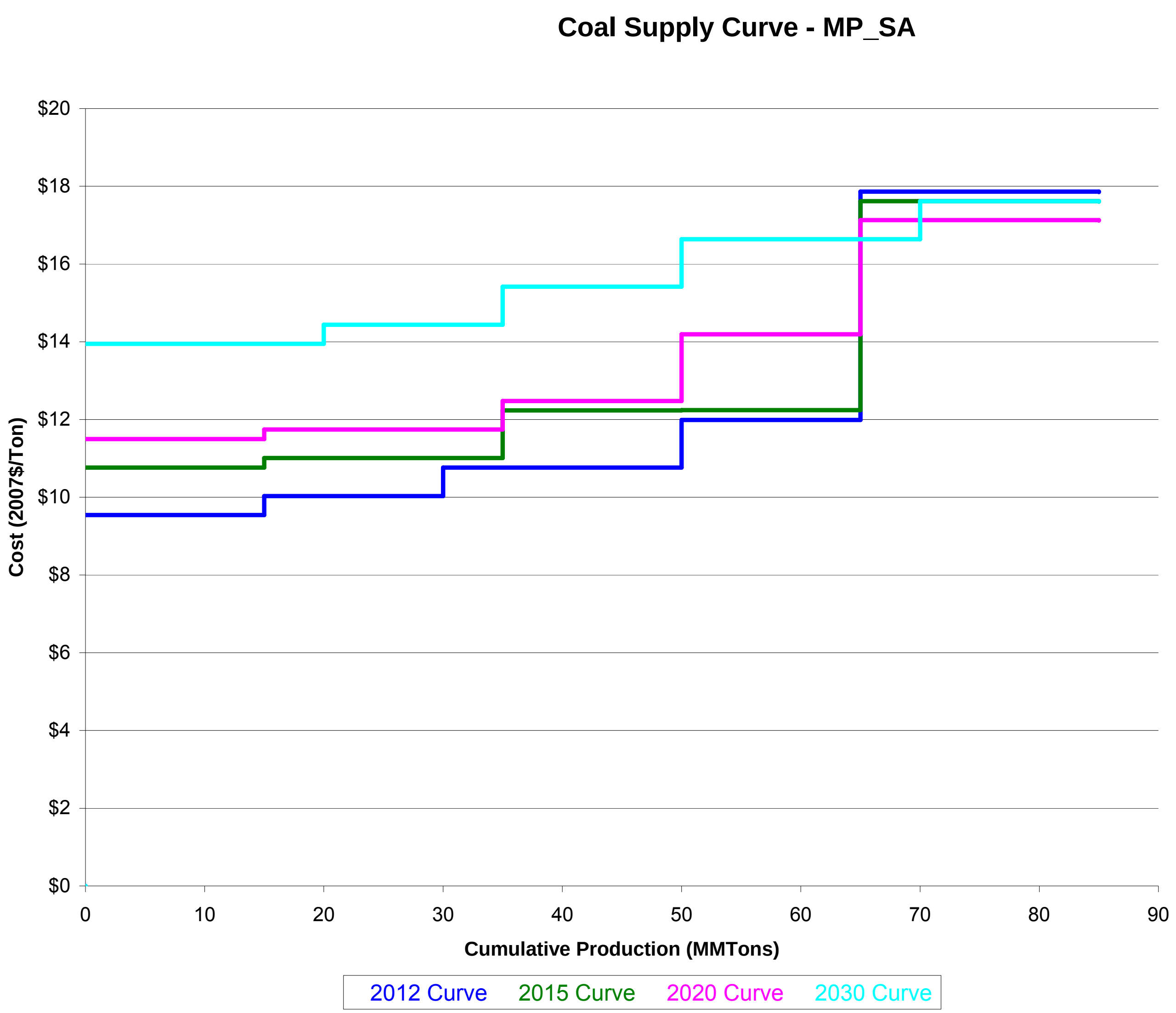
Coal Supply Curve - WH_SA

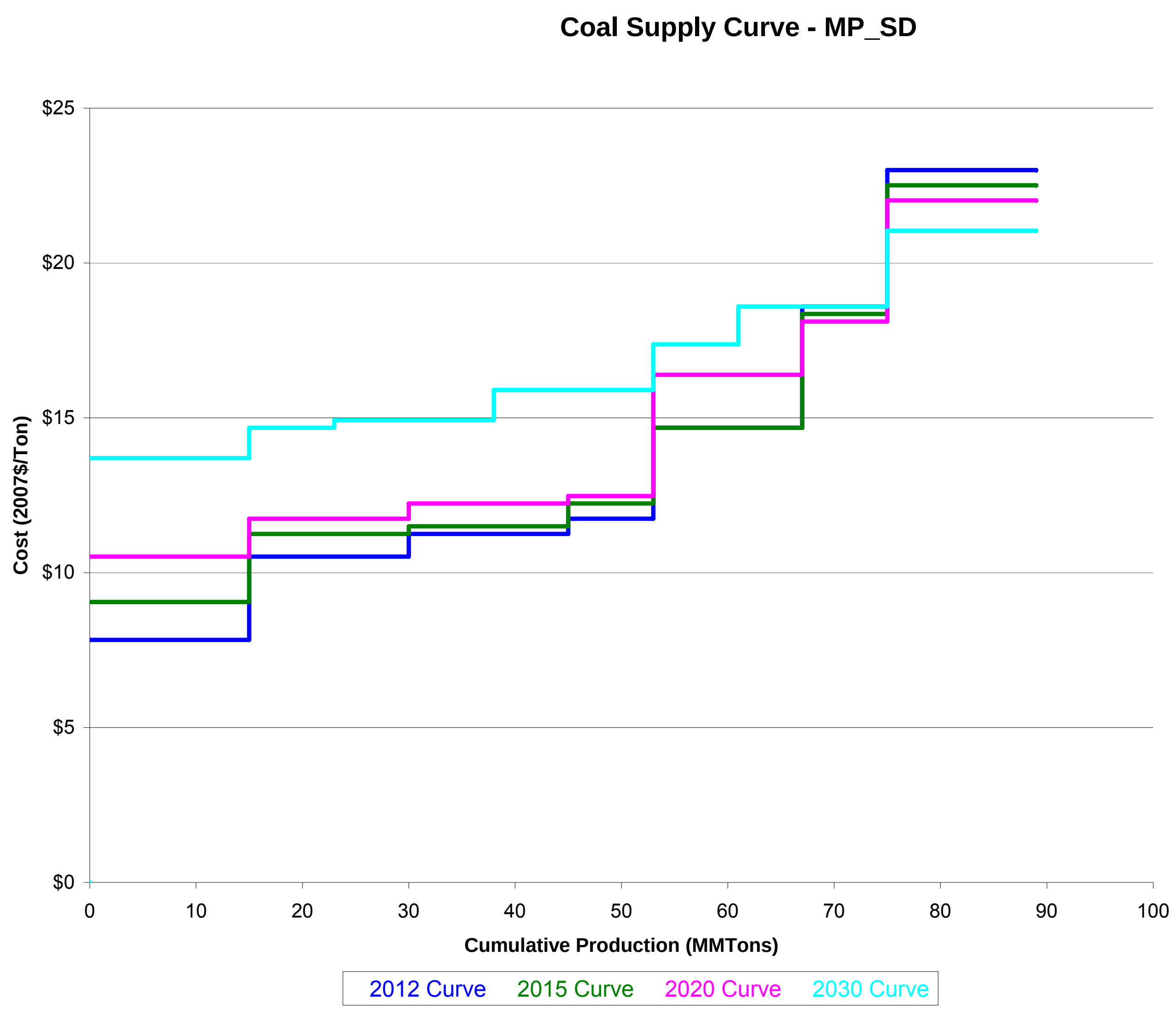


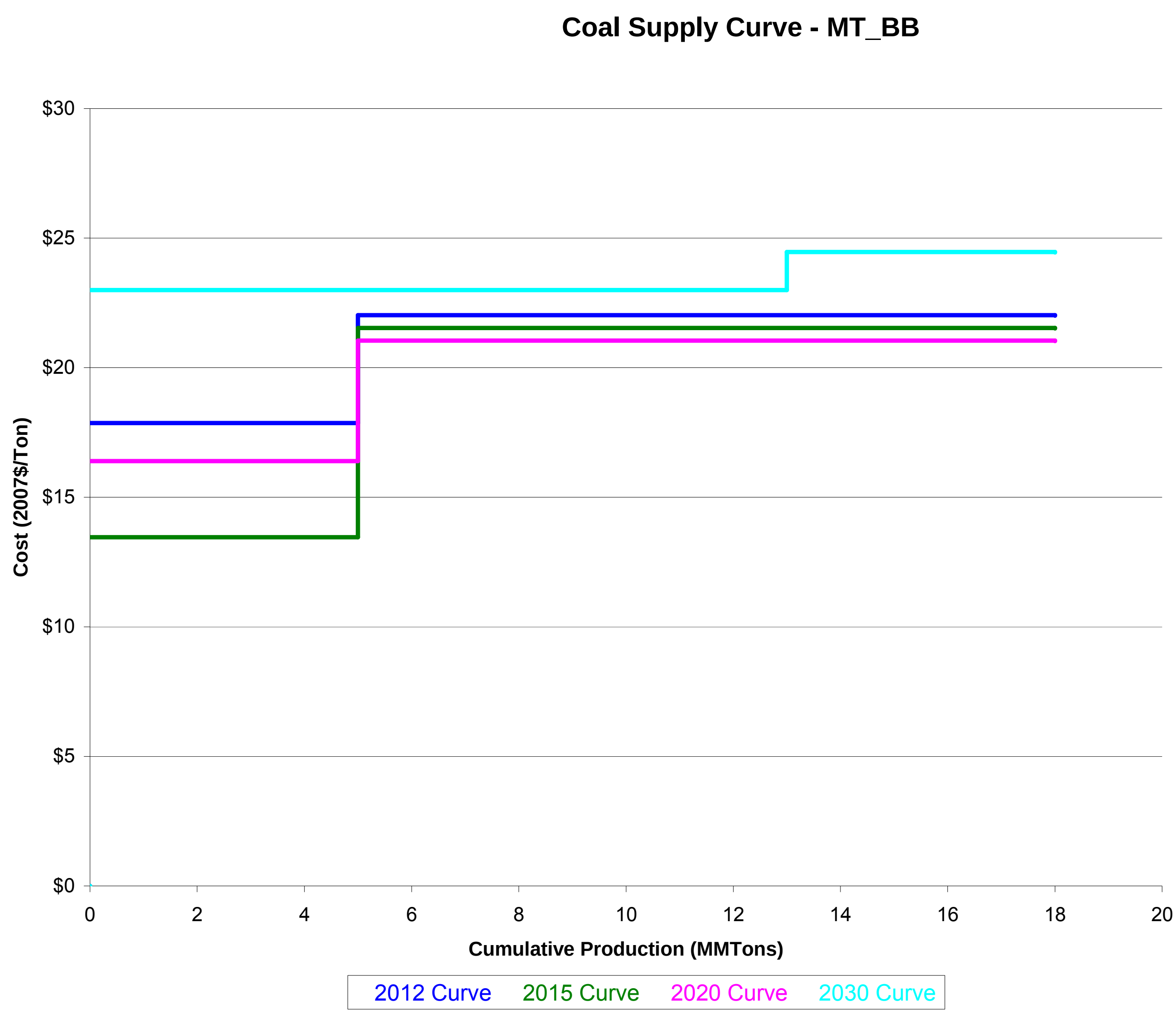


Coal Supply Curve - WH_SB
Cost (2007$/Ton)
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
0
10
20
30
40
50
60
70
80
90
100
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

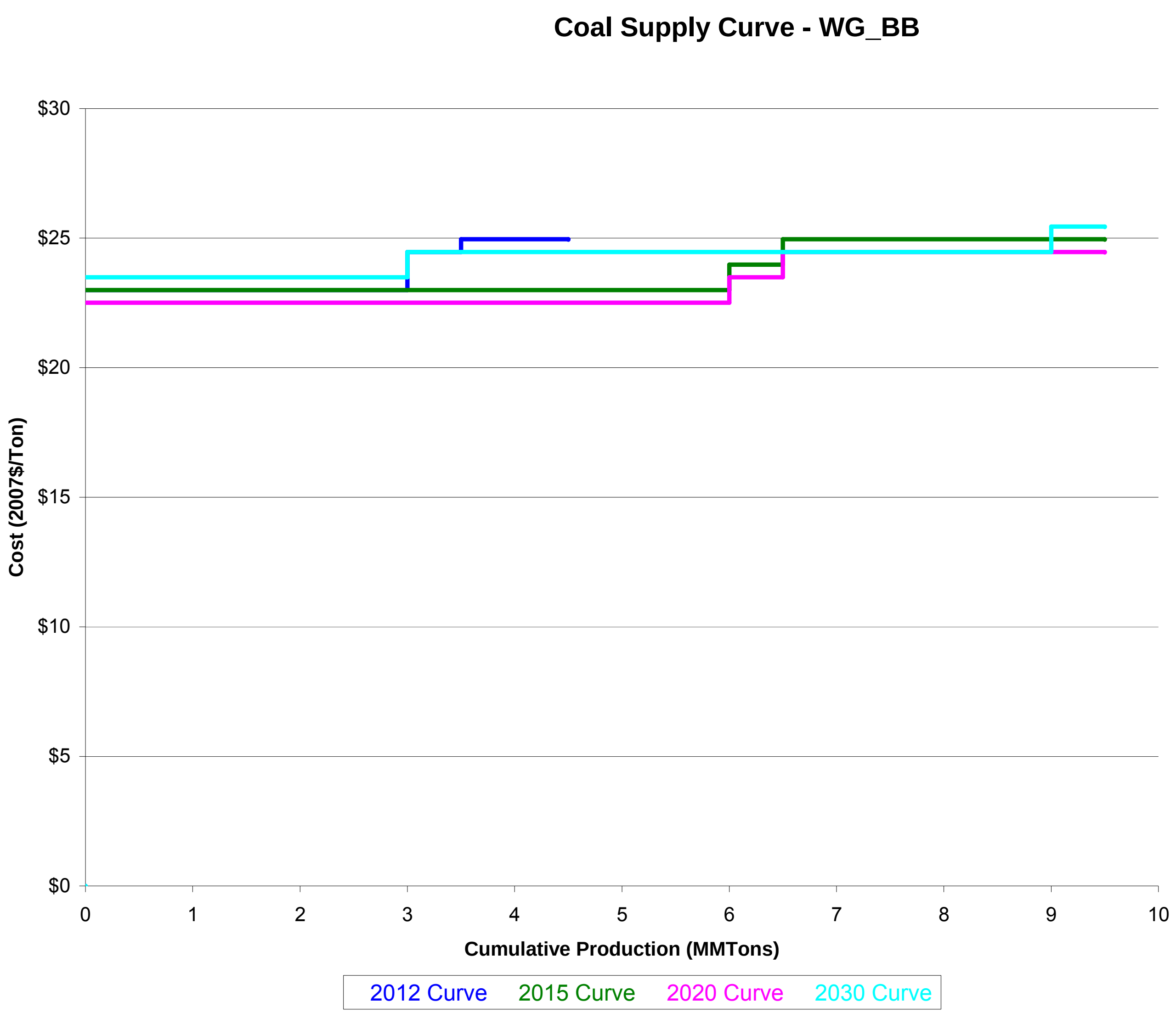

Coal Supply Curve - WL_SB
Cost (2007$/Ton)
$25
$20
$15
$10
$5
$0
0
100
200
300
400
500
600
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

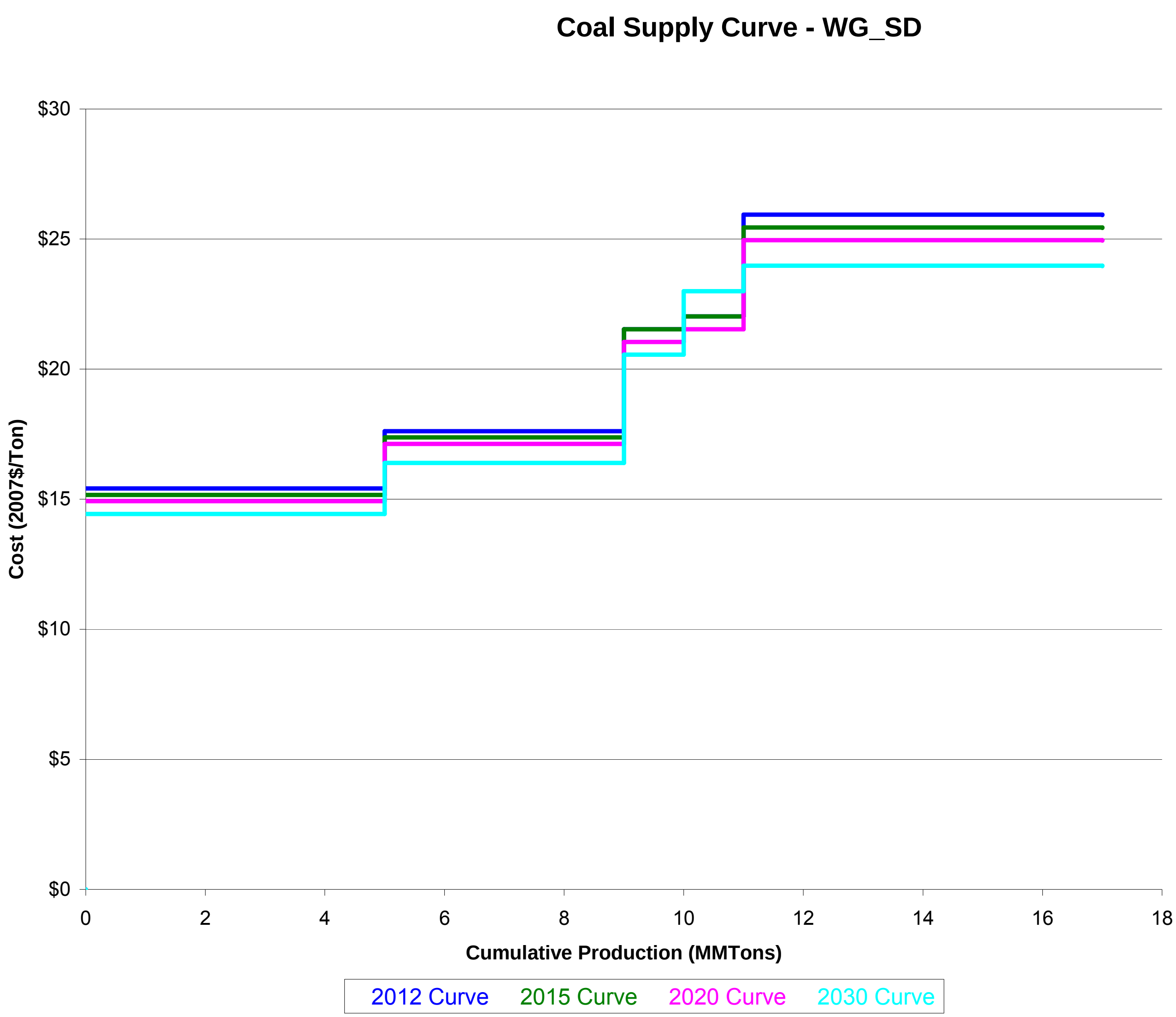

Coal Supply Curve - MP_SA
Cost (2007$/Ton)
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
0
10
20
30
40
50
60
70
80
90
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

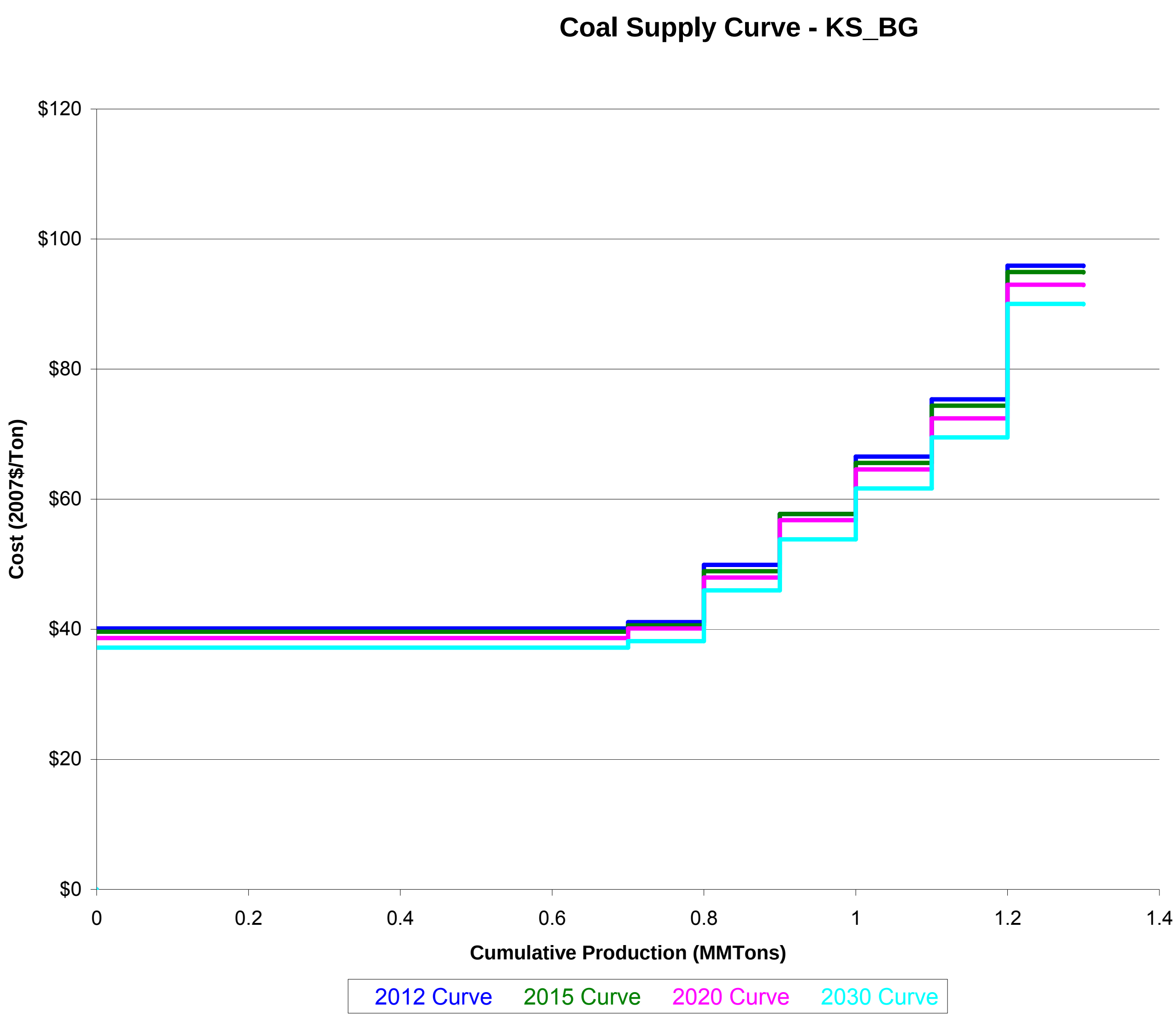

Coal Supply Curve - MP_SD
Cost (2007$/Ton)
$25
$20
$15
$10
$5
$0
0
10
20
30
40
50
60
70
80
90
100
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

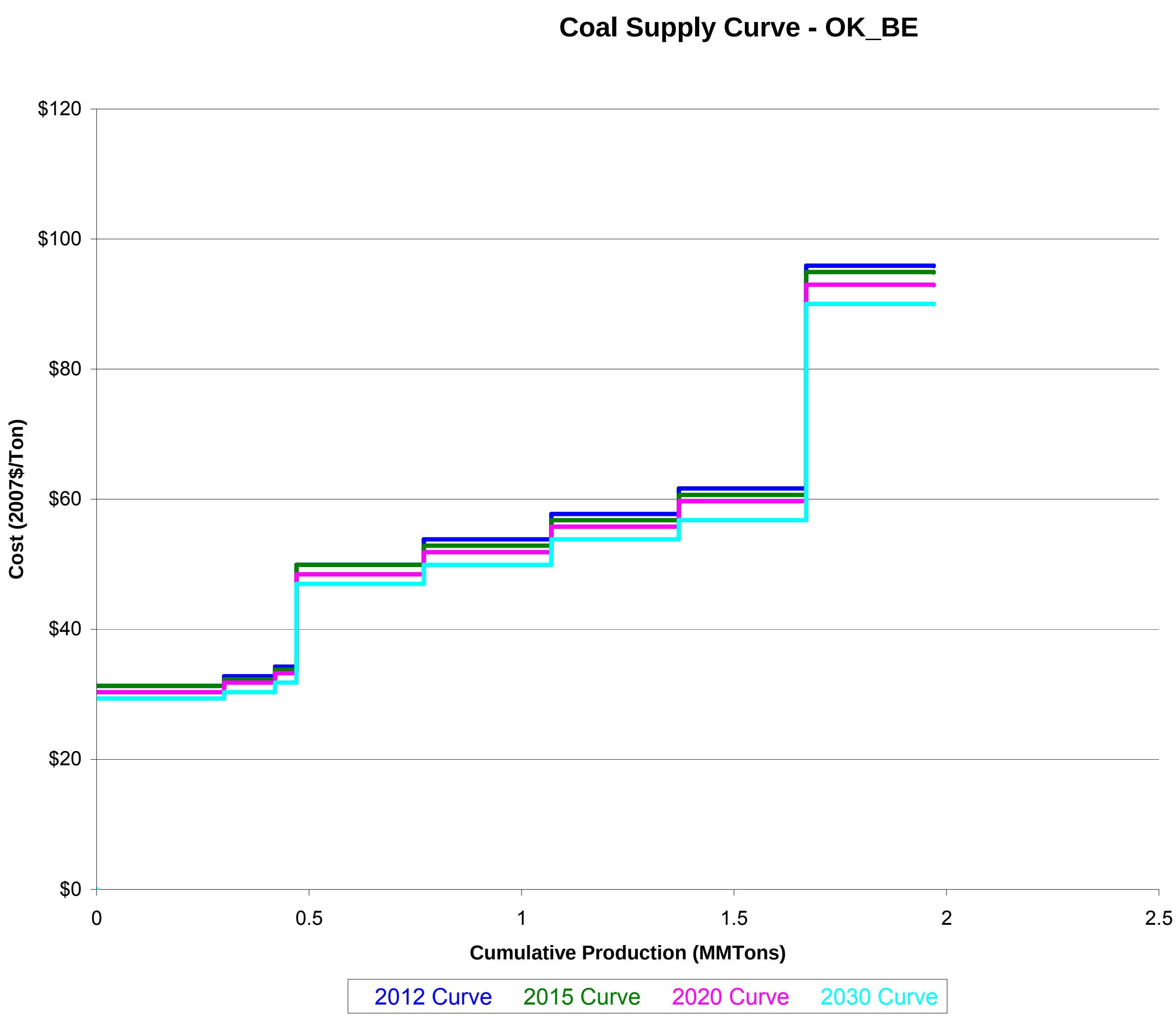


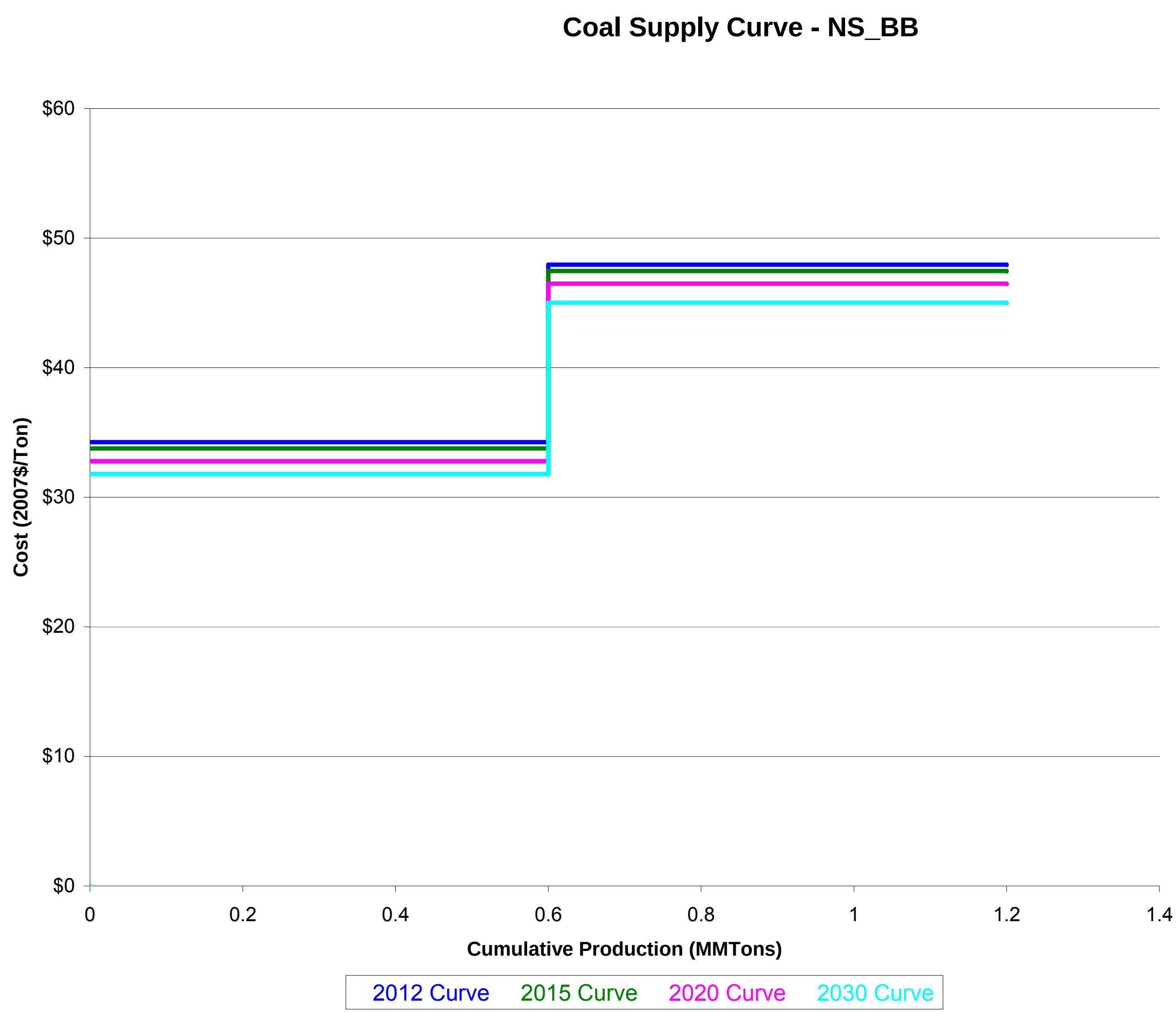
Coal Supply Curve - MT_BB
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
20
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

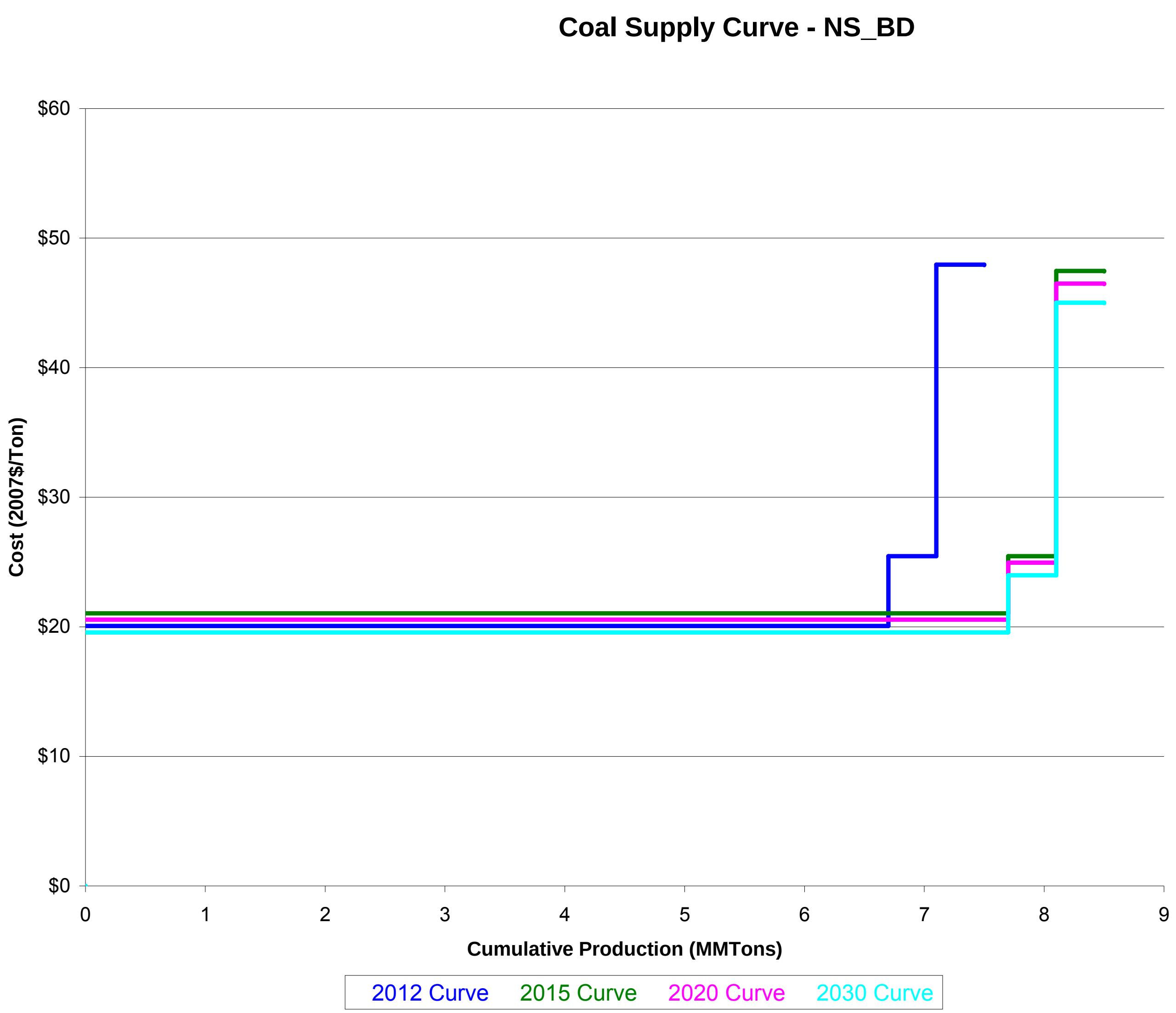

Coal Supply Curve - WG_BB
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
10
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - WG_SD
Cost (2007$/Ton)
$30
$25
$20
$15
$10
$5
$0
0
2
4
6
8
10
12
14
16
18
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

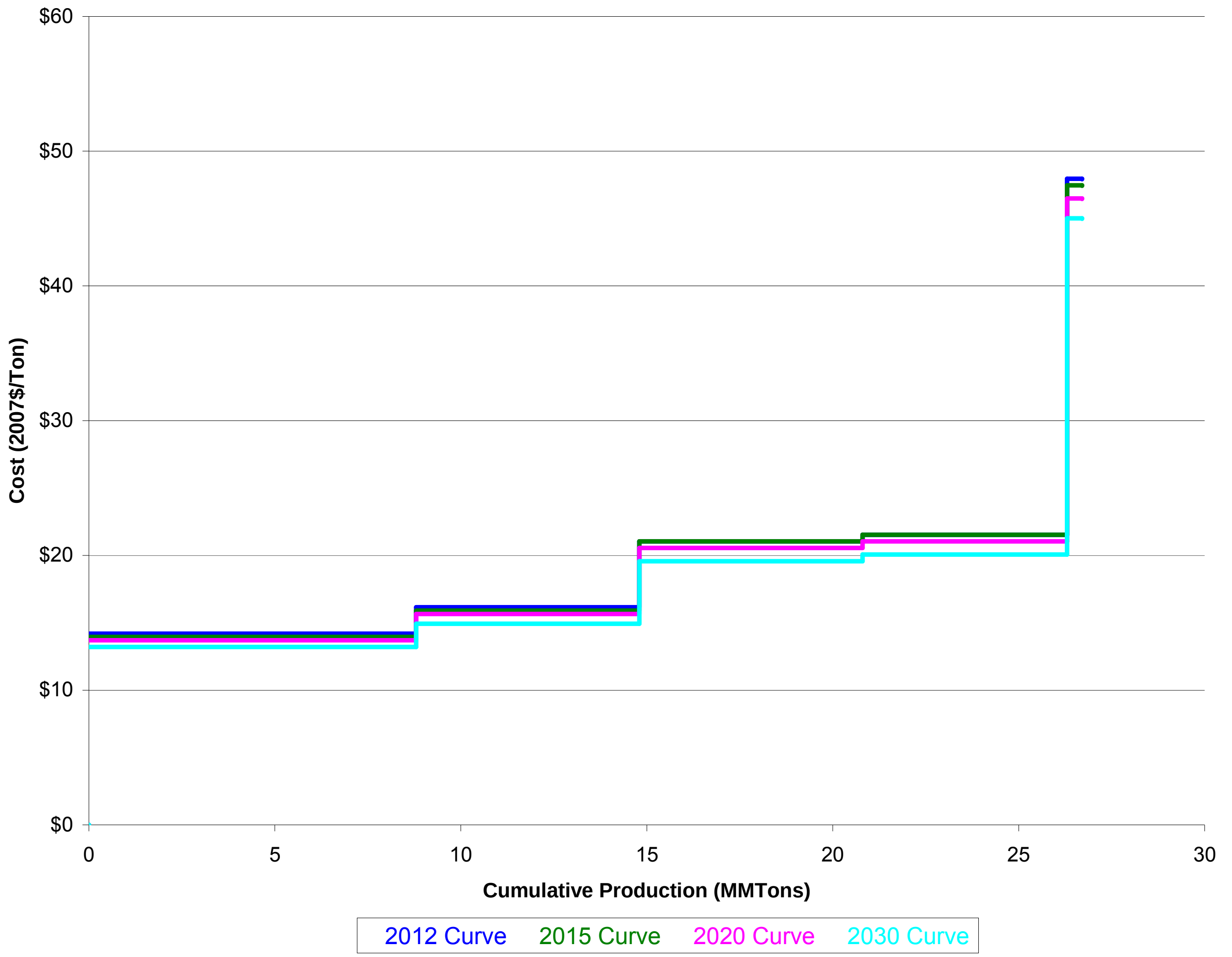

Coal Supply Curve - KS_BG
$120
$100
$80
$60
$40
$20
$0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
Cost (2007$/Ton)
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

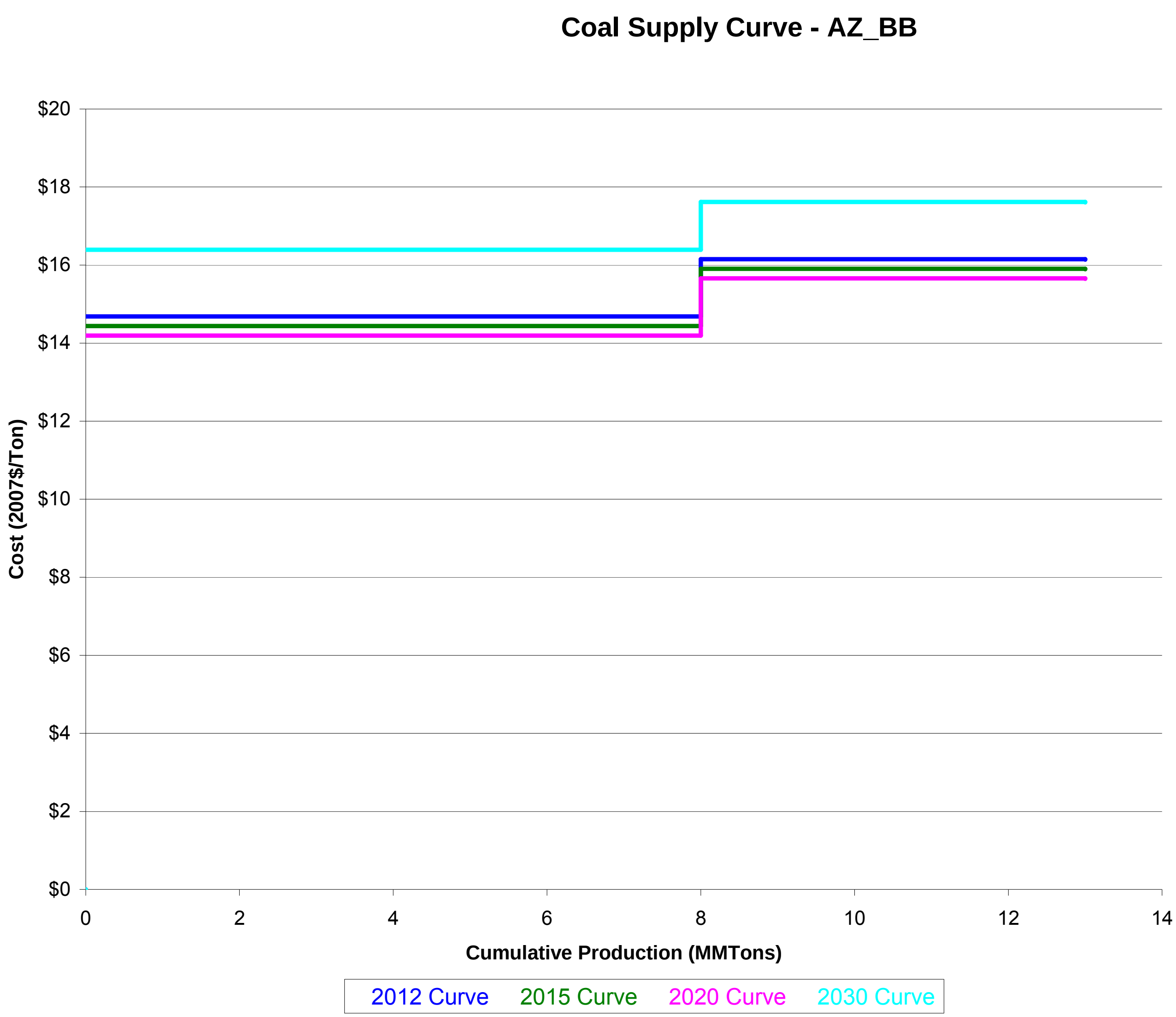

Coal Supply Curve - OK_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

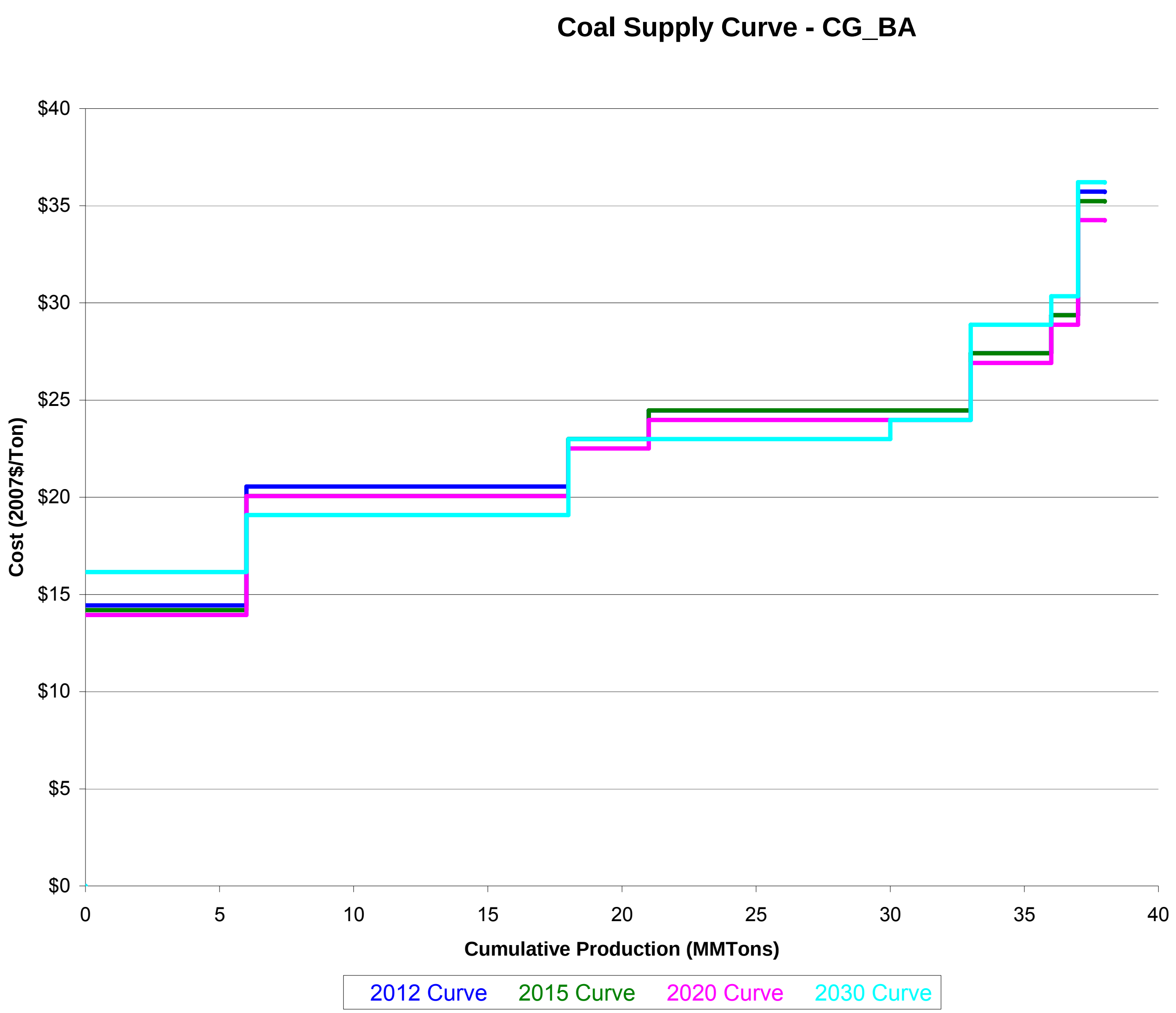

Coal Supply Curve - NS_BB
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - NS_BD
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

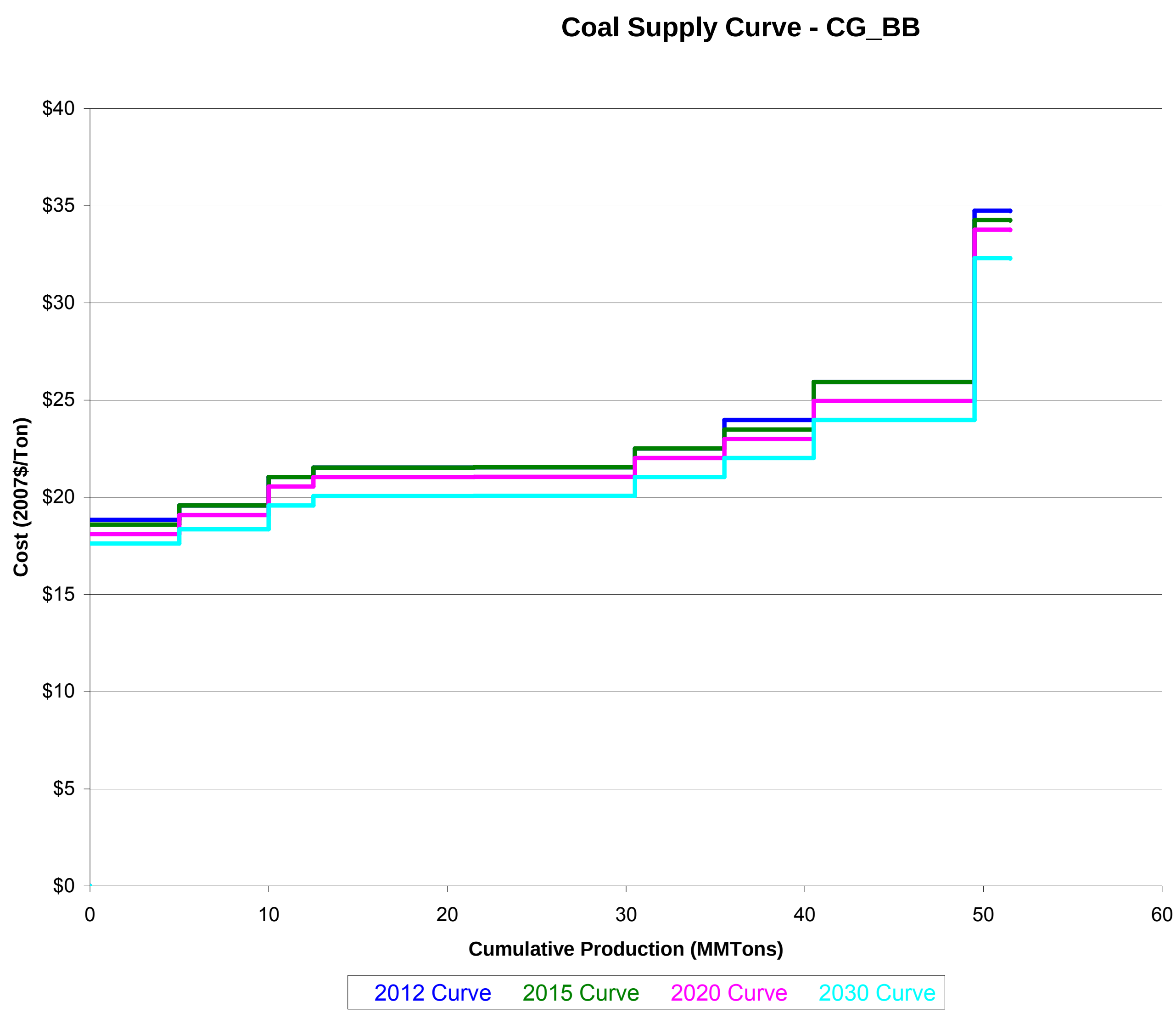
Coal Supply Curve - NS_BE

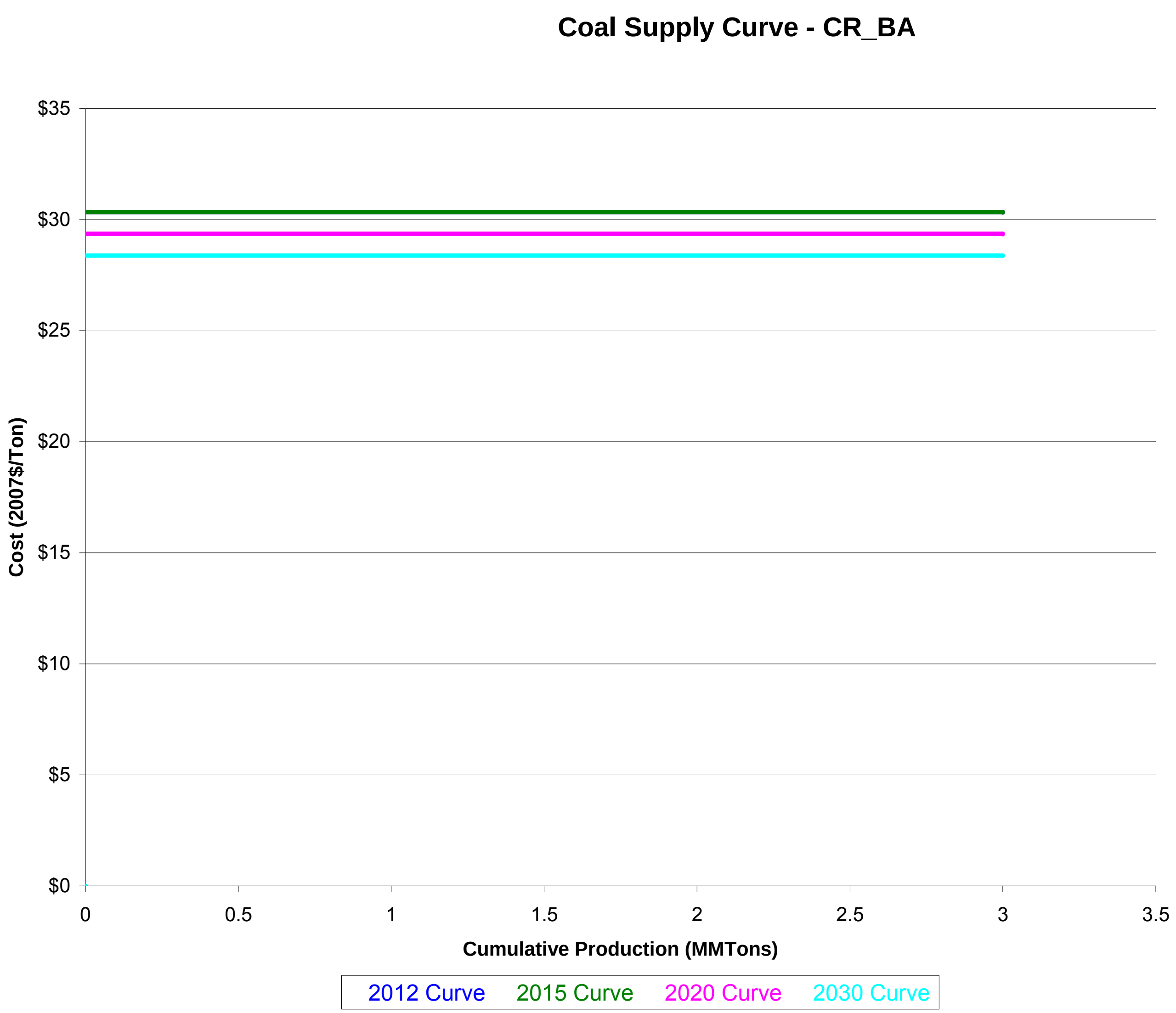


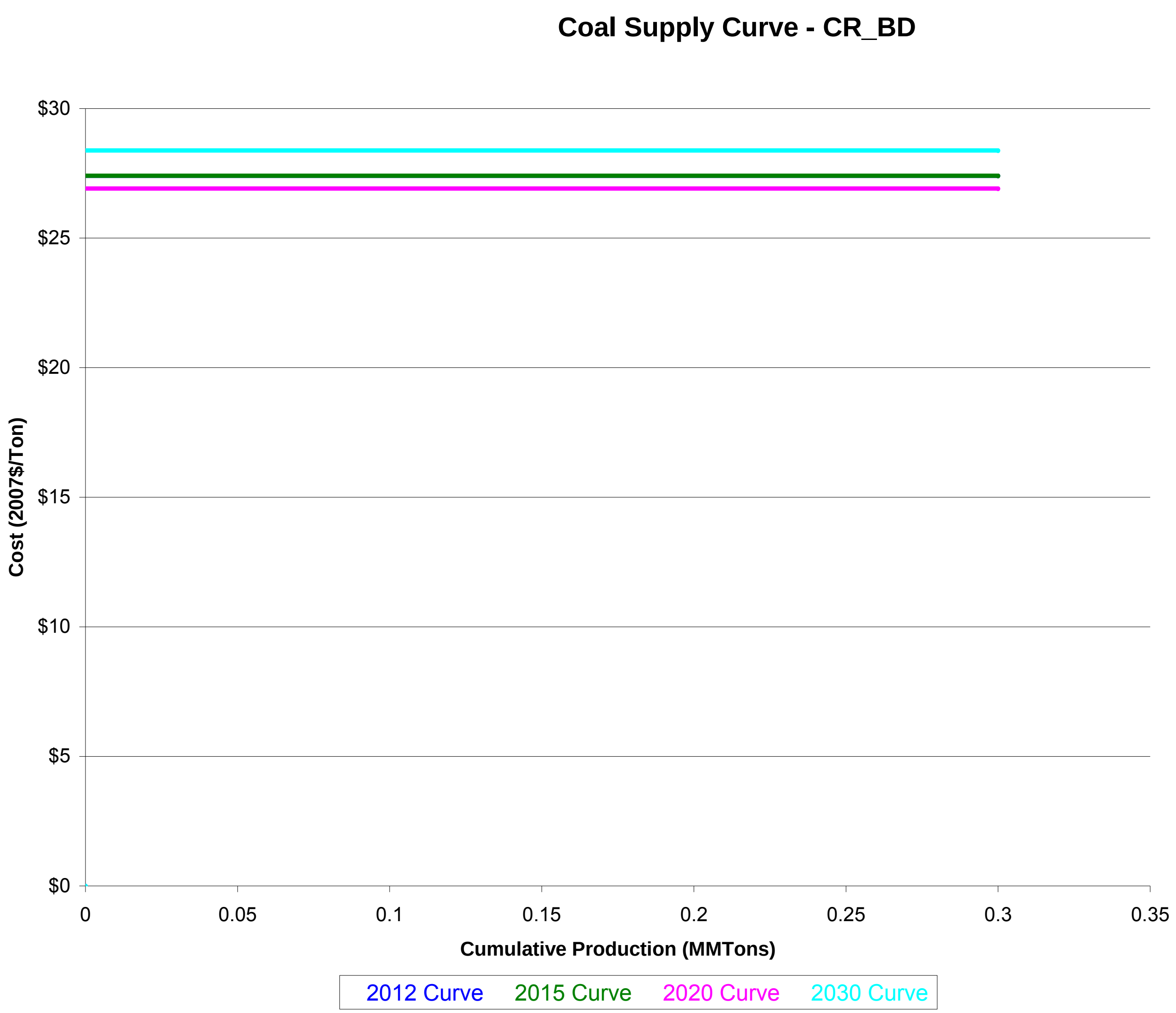

Coal Supply Curve - AZ_BB
Cost (2007$/Ton)
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
0
2
4
6
8
10
12
14
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

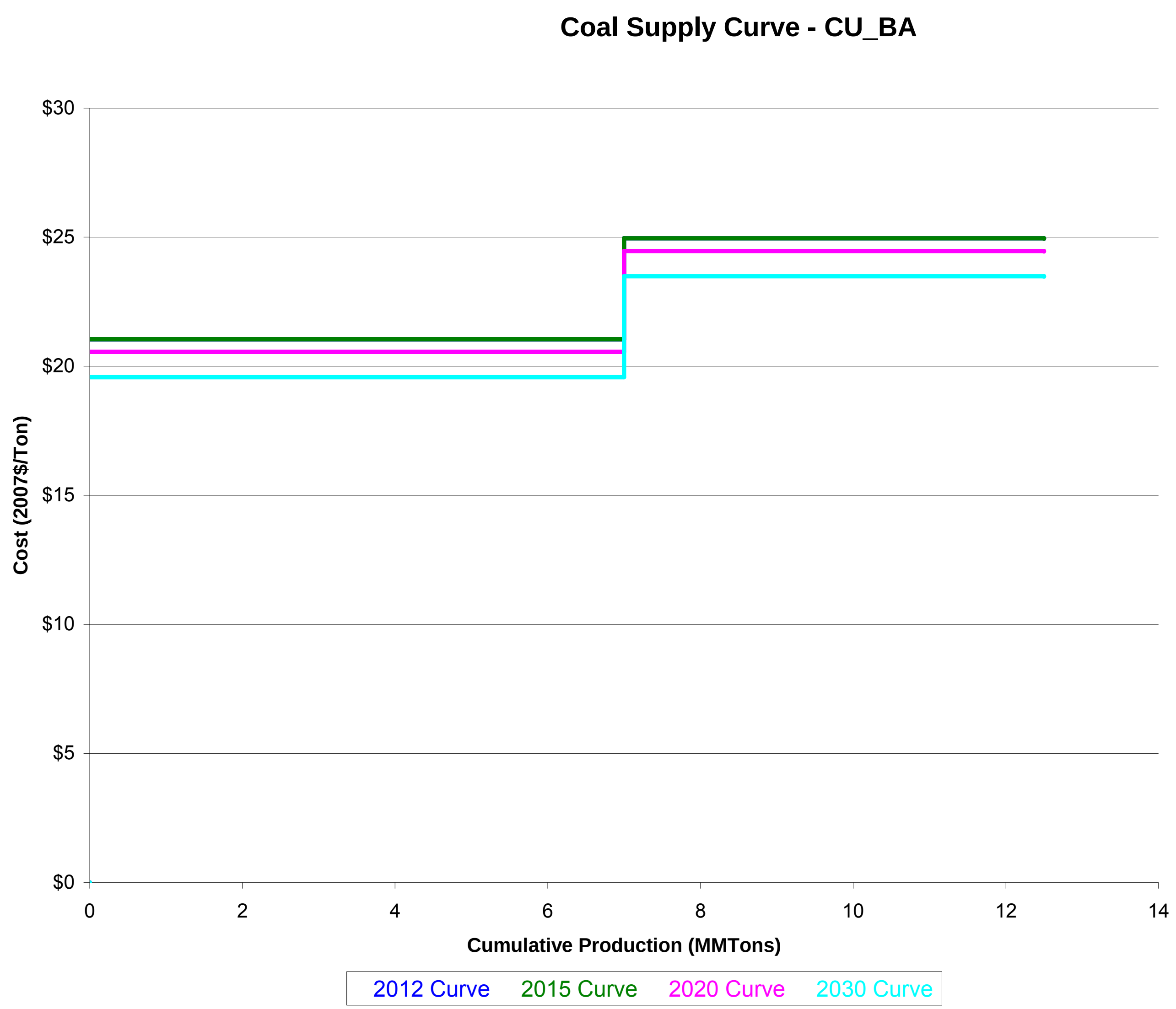


Coal Supply Curve - CG_BA
Cost (2007$/Ton)
$40
$35
$30
$25
$20
$15
$10
$5
$0
0
5
10
15
20
25
30
35
40
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

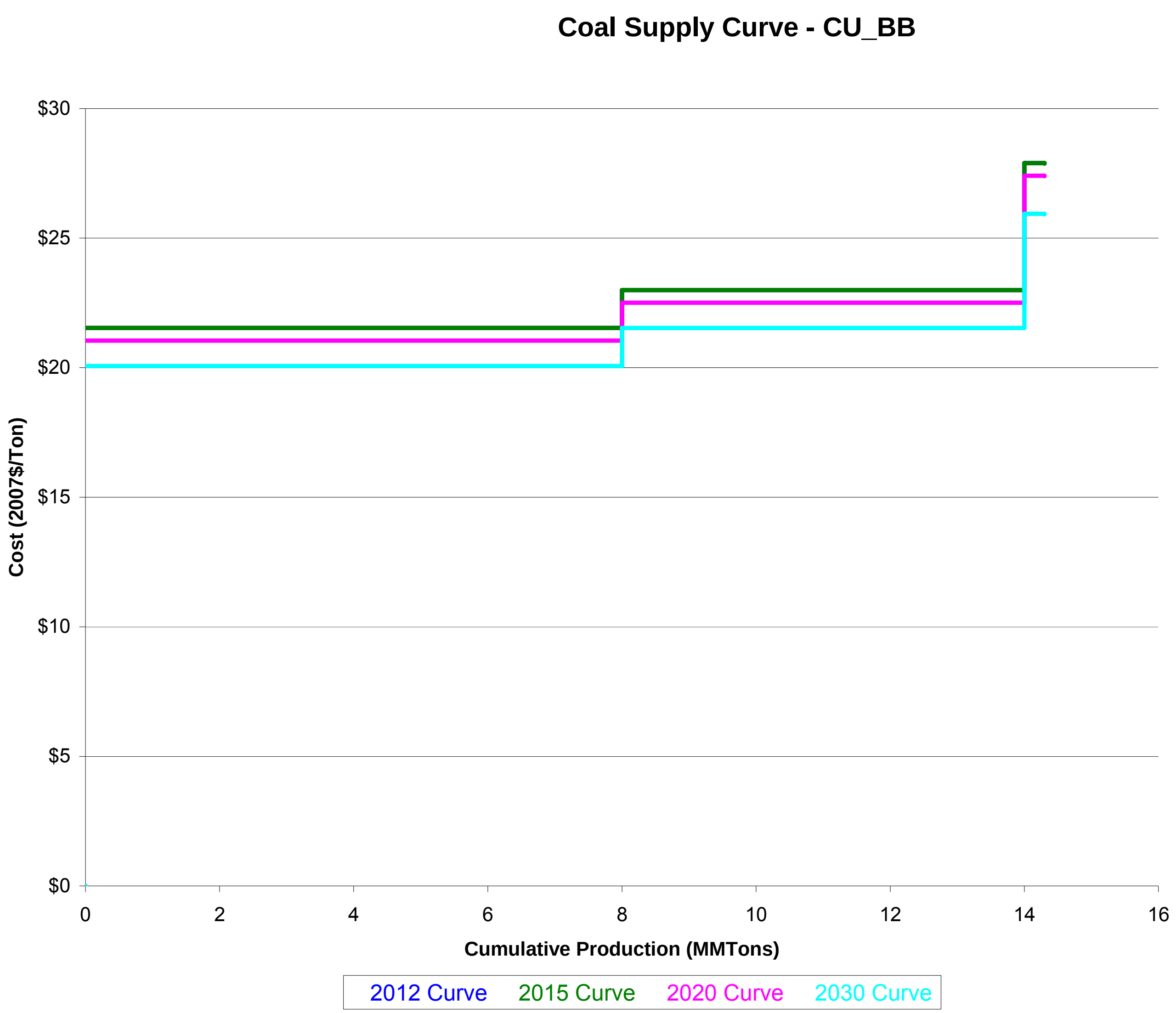

Coal Supply Curve - CG_BB
Cost (2007$/Ton)
$40
$35
$30
$25
$20
$15
$10
$5
$0
0
10
20
30
40
50
60
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

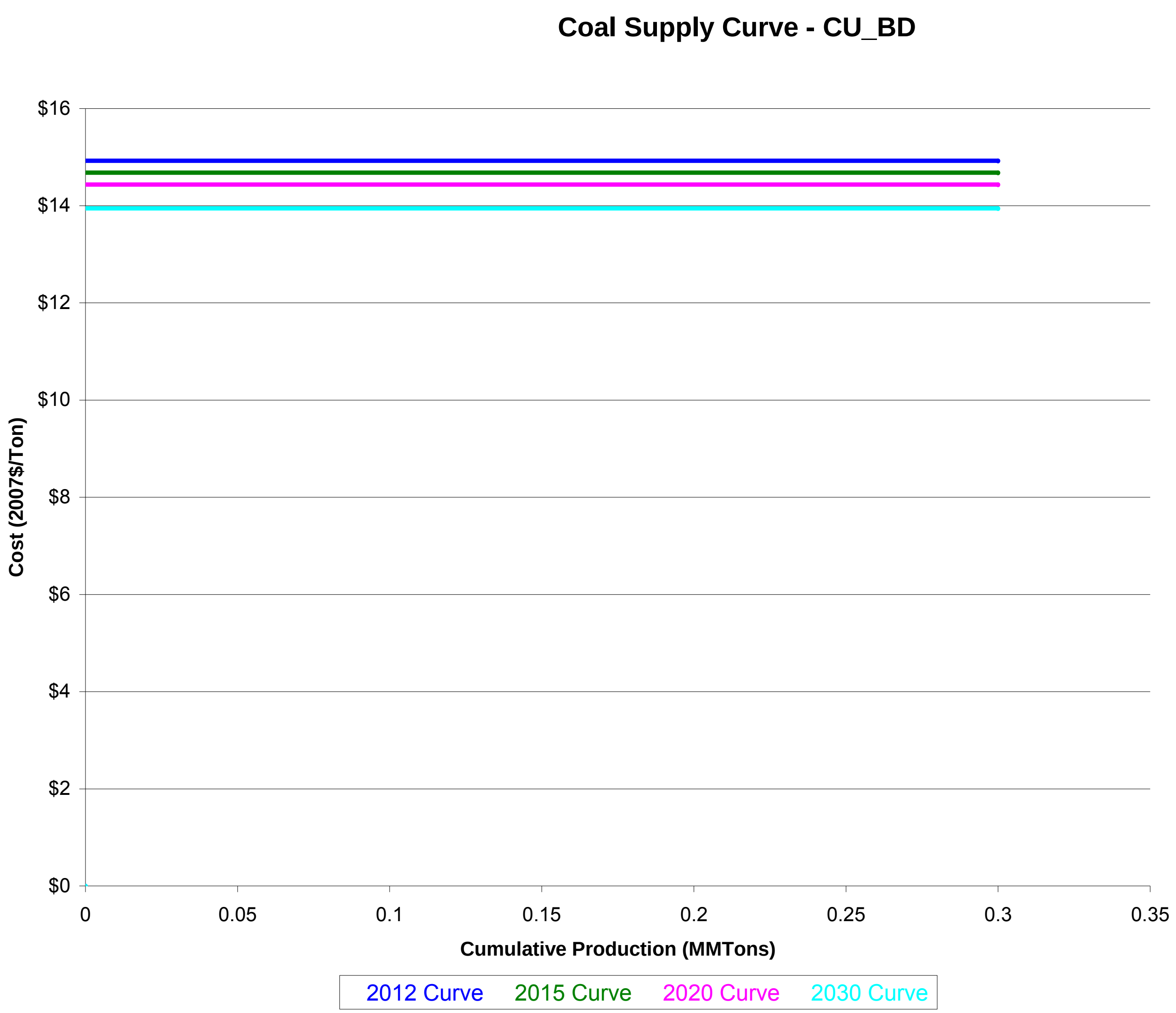

Coal Supply Curve - CR_BA
Cost (2007$/Ton)
$35
$30
$25
$20
$15
$10
$5
$0
0
0.5
1
1.5
2
2.5
3
3.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

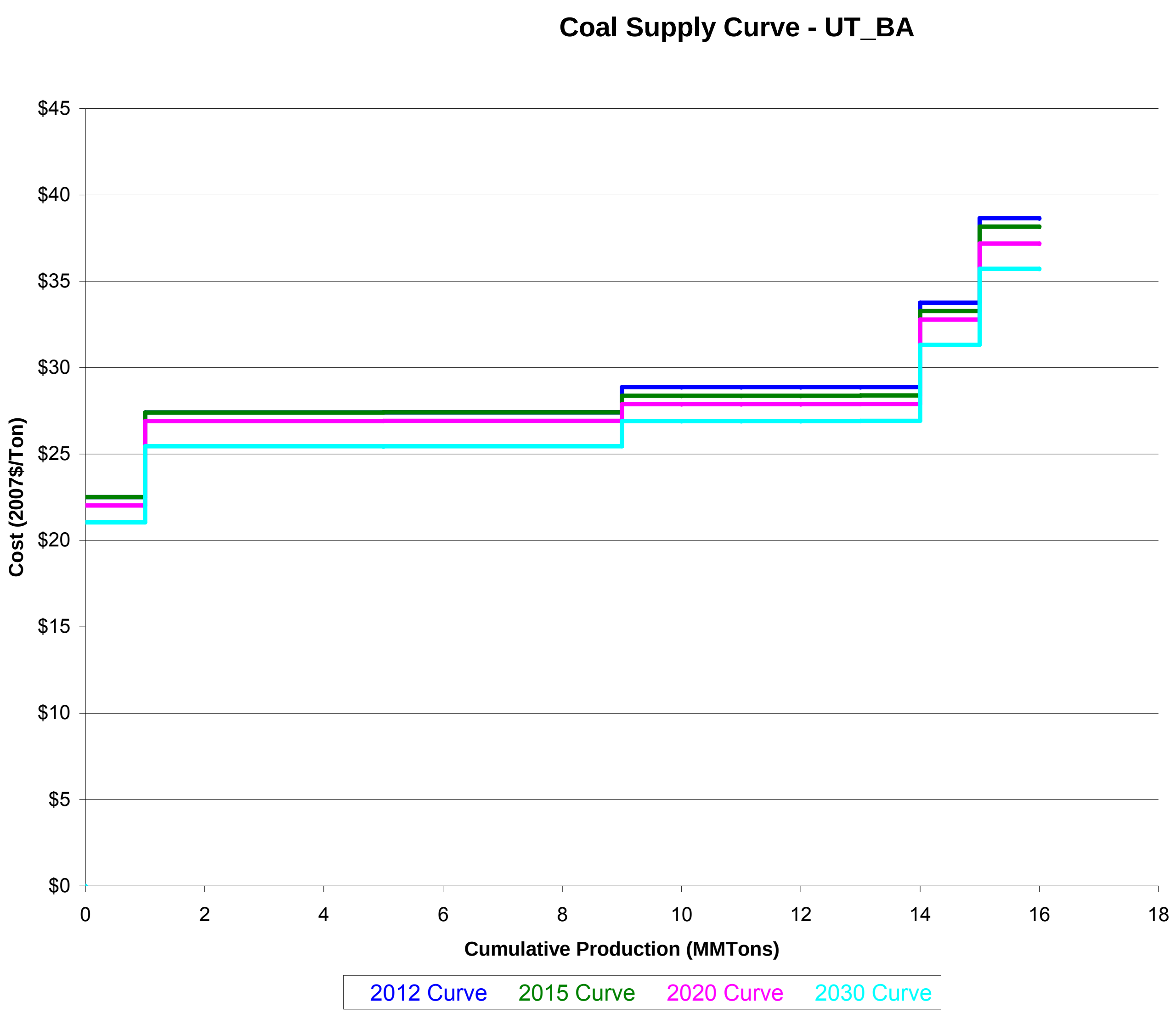

Coal Supply Curve - CR_BD
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

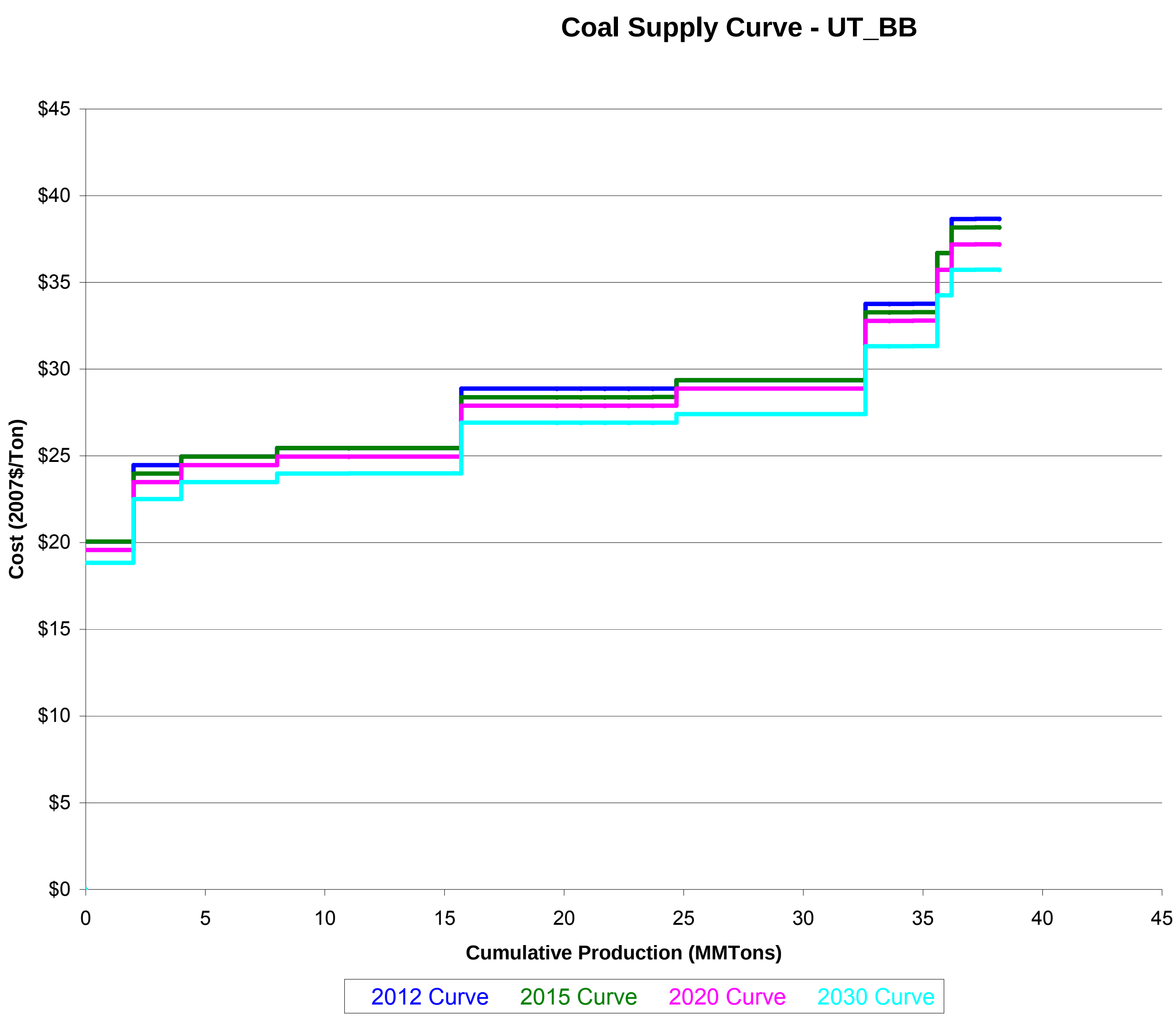


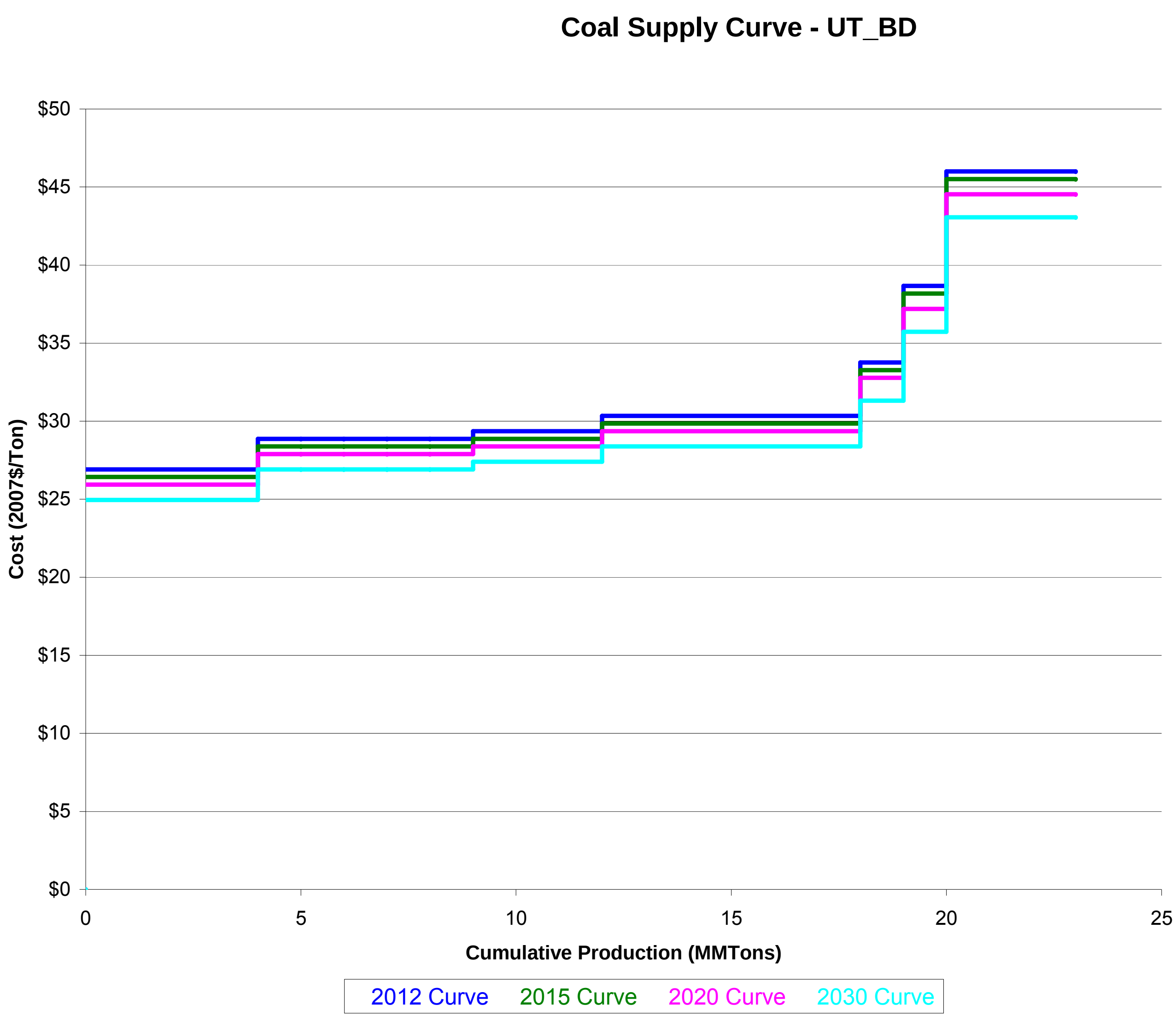
Coal Supply Curve - CU_BA
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - CU_BB
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

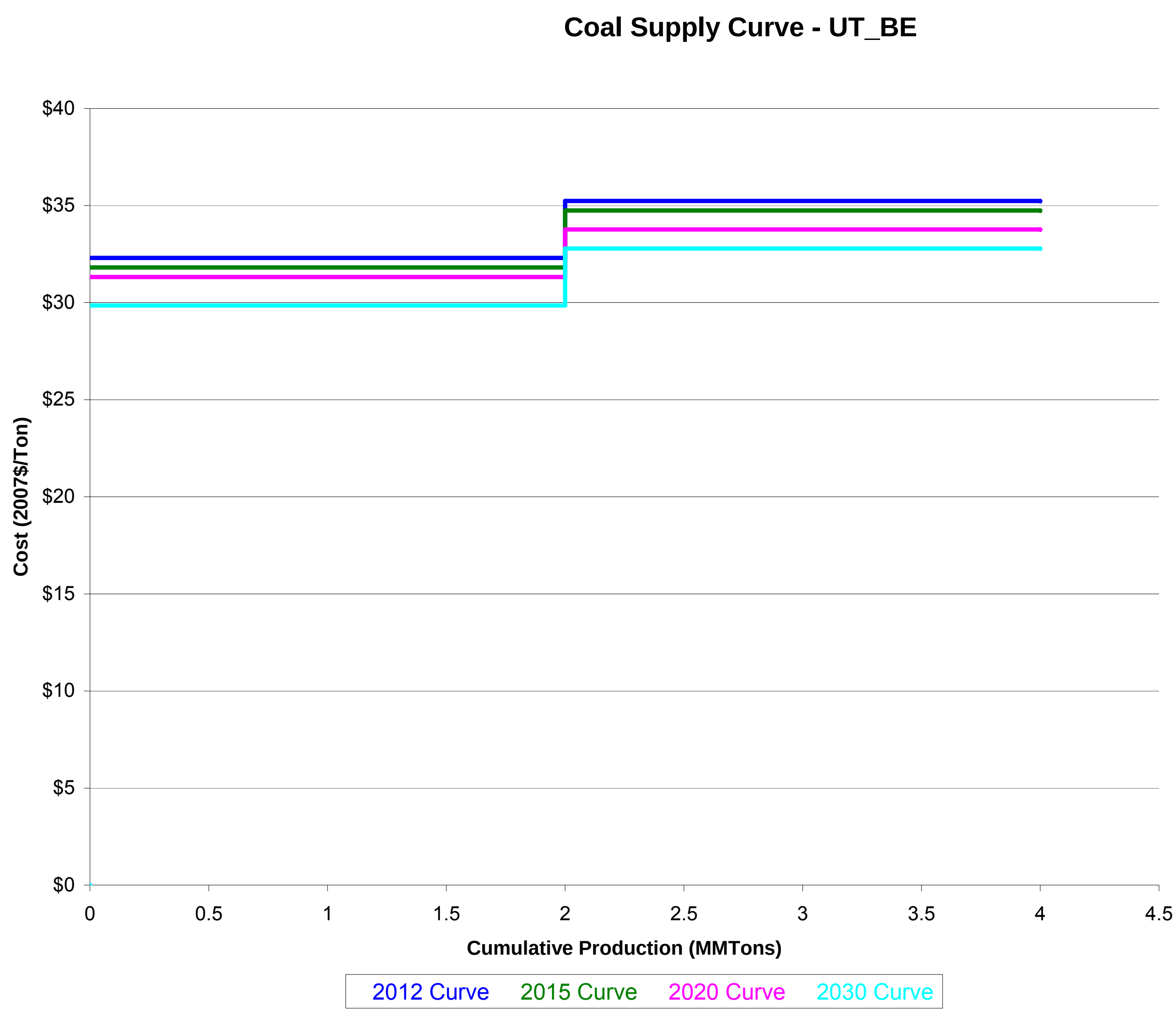

Coal Supply Curve - CU_BD
Cost (2007$/Ton)
$16
$14
$12
$10
$8
$6
$4
$2
$0
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

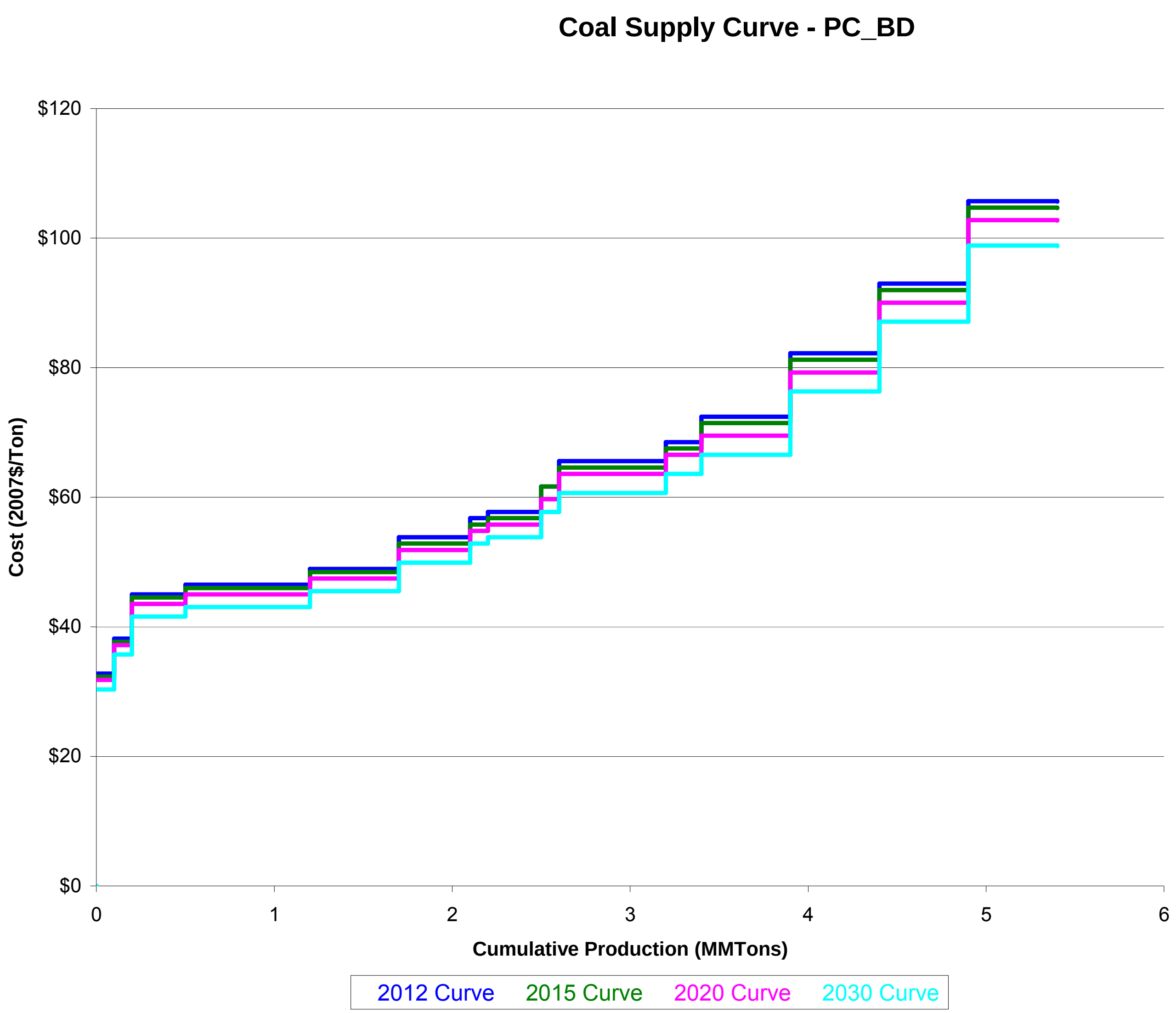

Coal Supply Curve - UT_BA
$45
$40
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

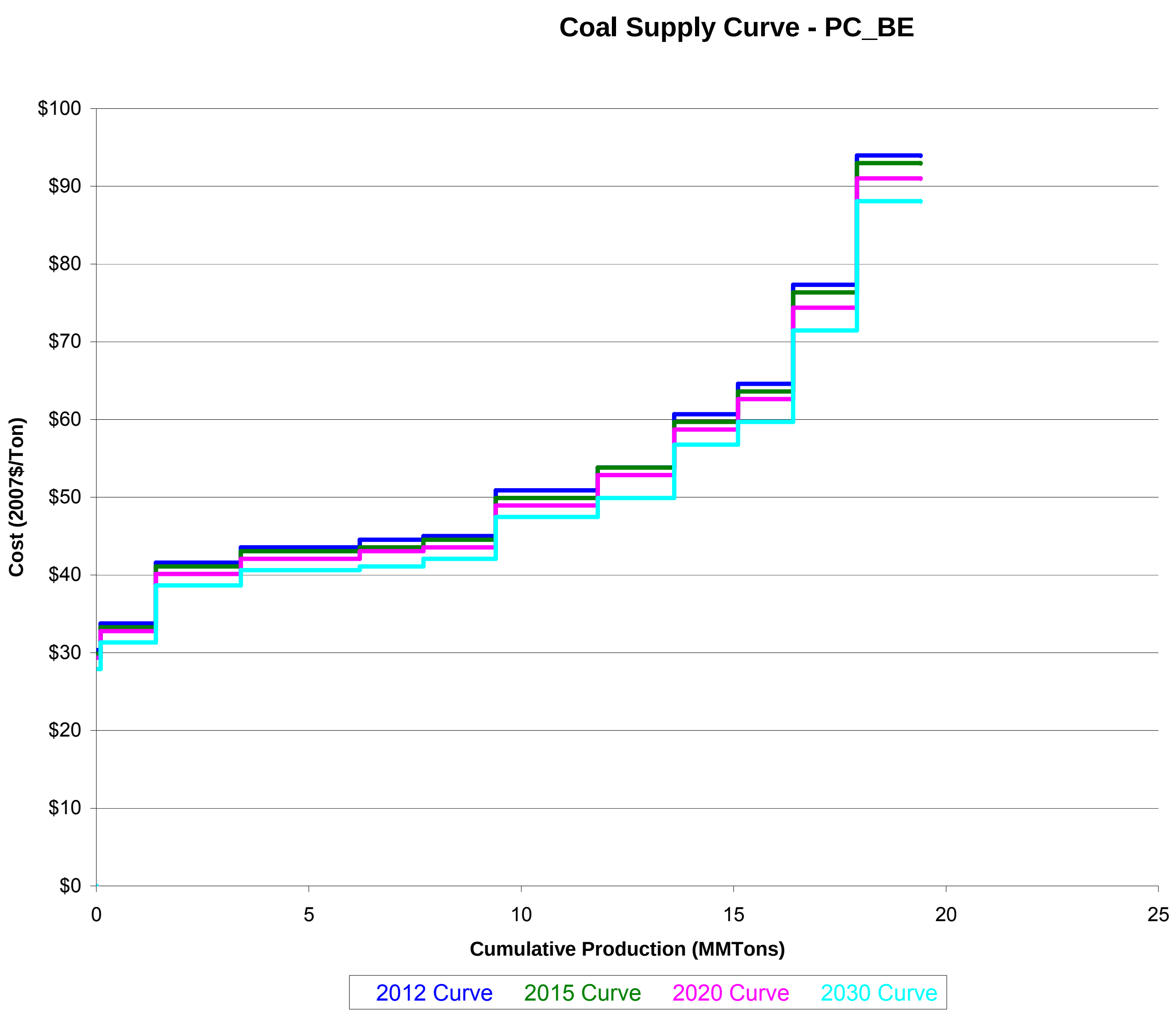

Coal Supply Curve - UT_BB
$45
$40
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
35
40
45
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve



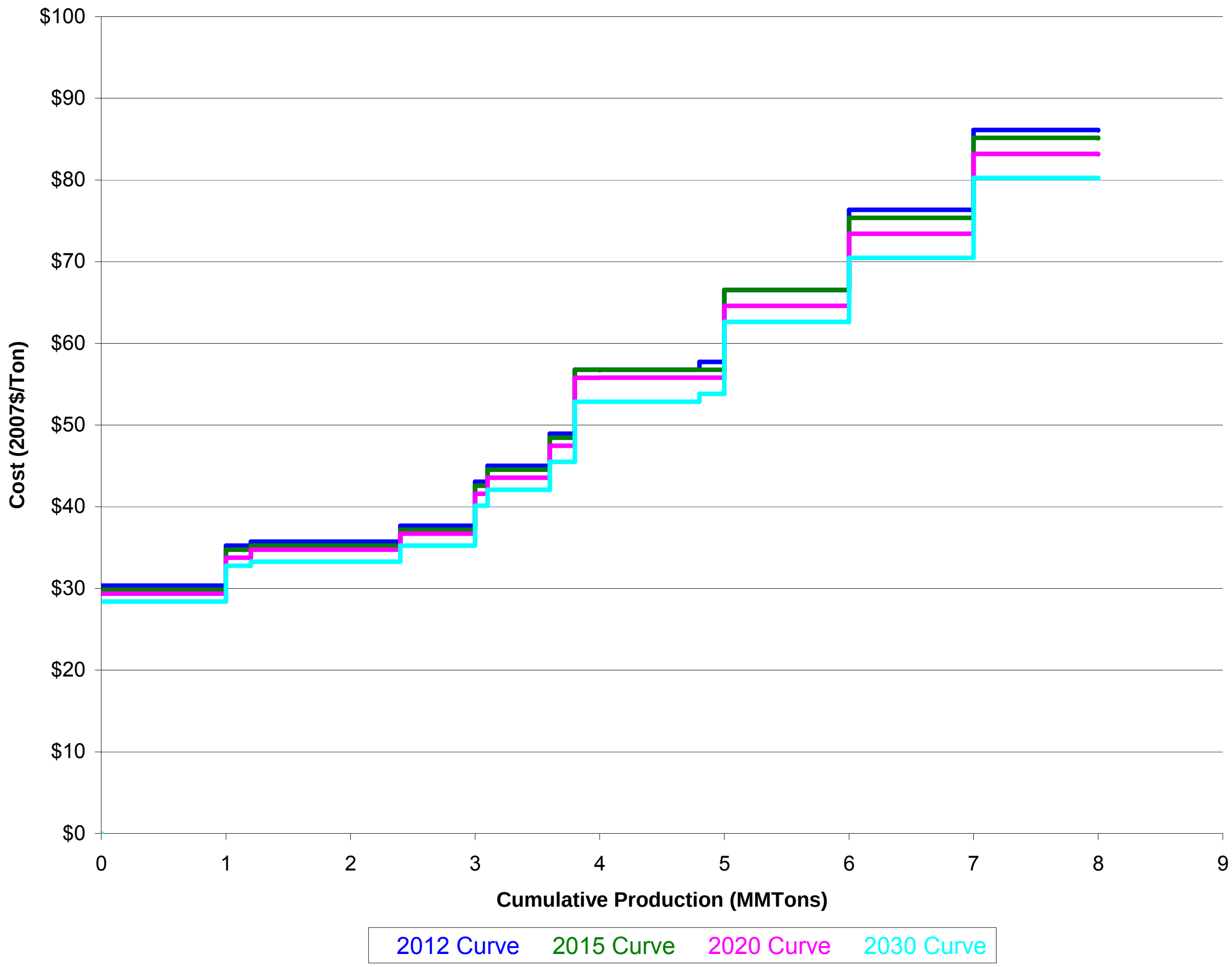
Coal Supply Curve - UT_BD
Cost (2007$/Ton)
$50
$45
$40
$35
$30
$25
$20
$15
$10
$5
$0
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

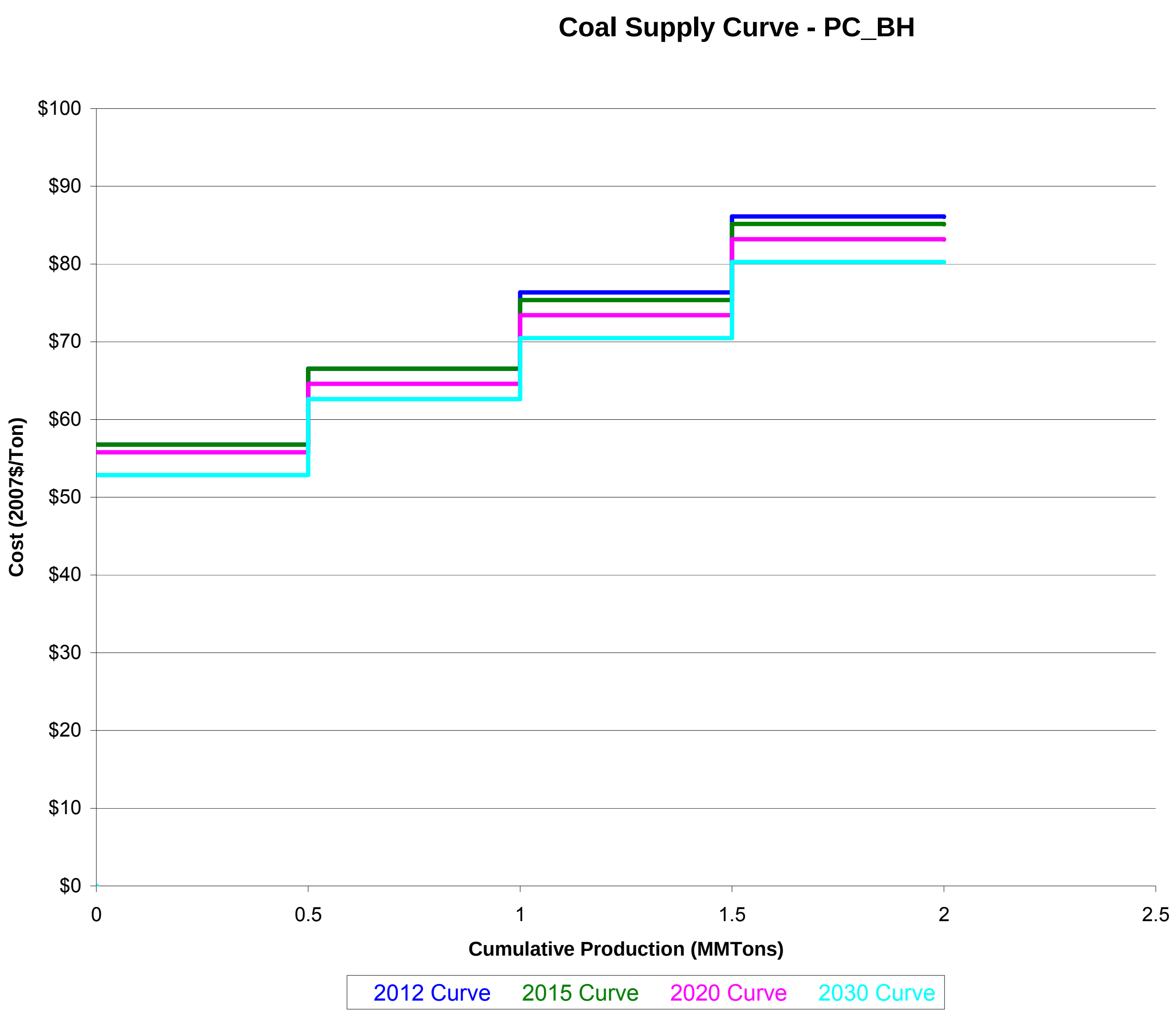

Coal Supply Curve - UT_BE
$40
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - PC_BD
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

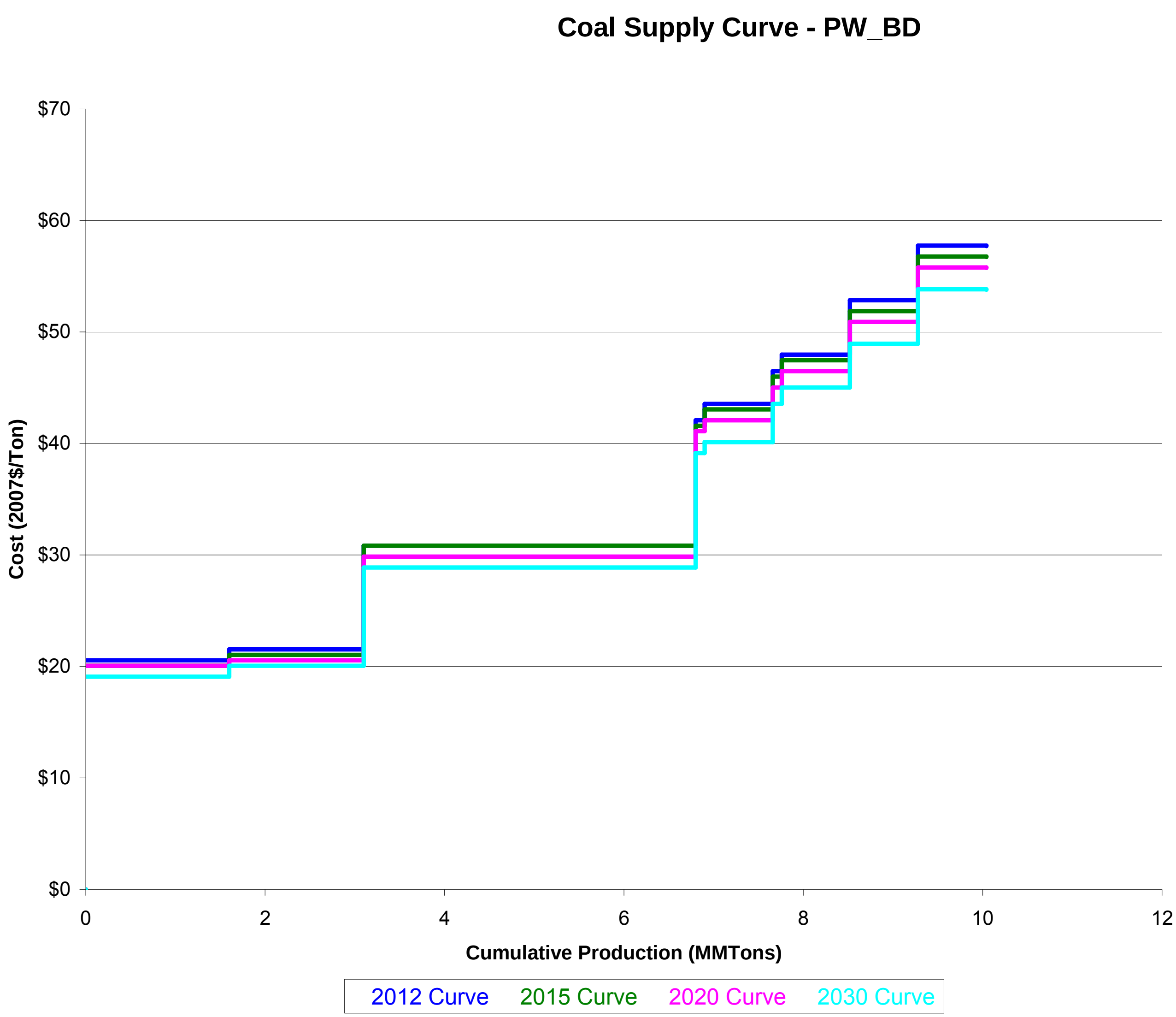

Coal Supply Curve - PC_BE
Cost (2007$/Ton)
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

Coal Supply Curve - PC_BG

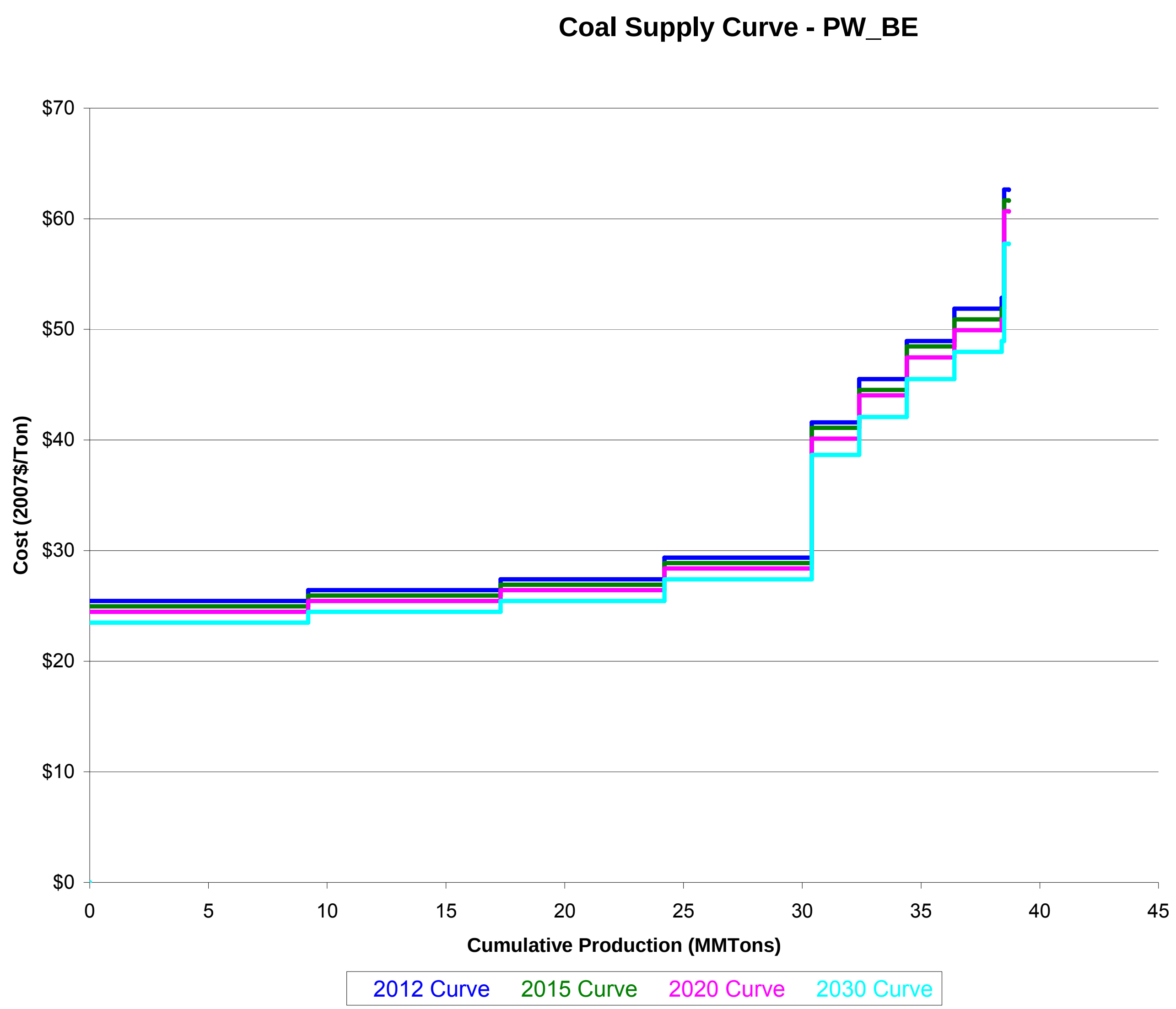




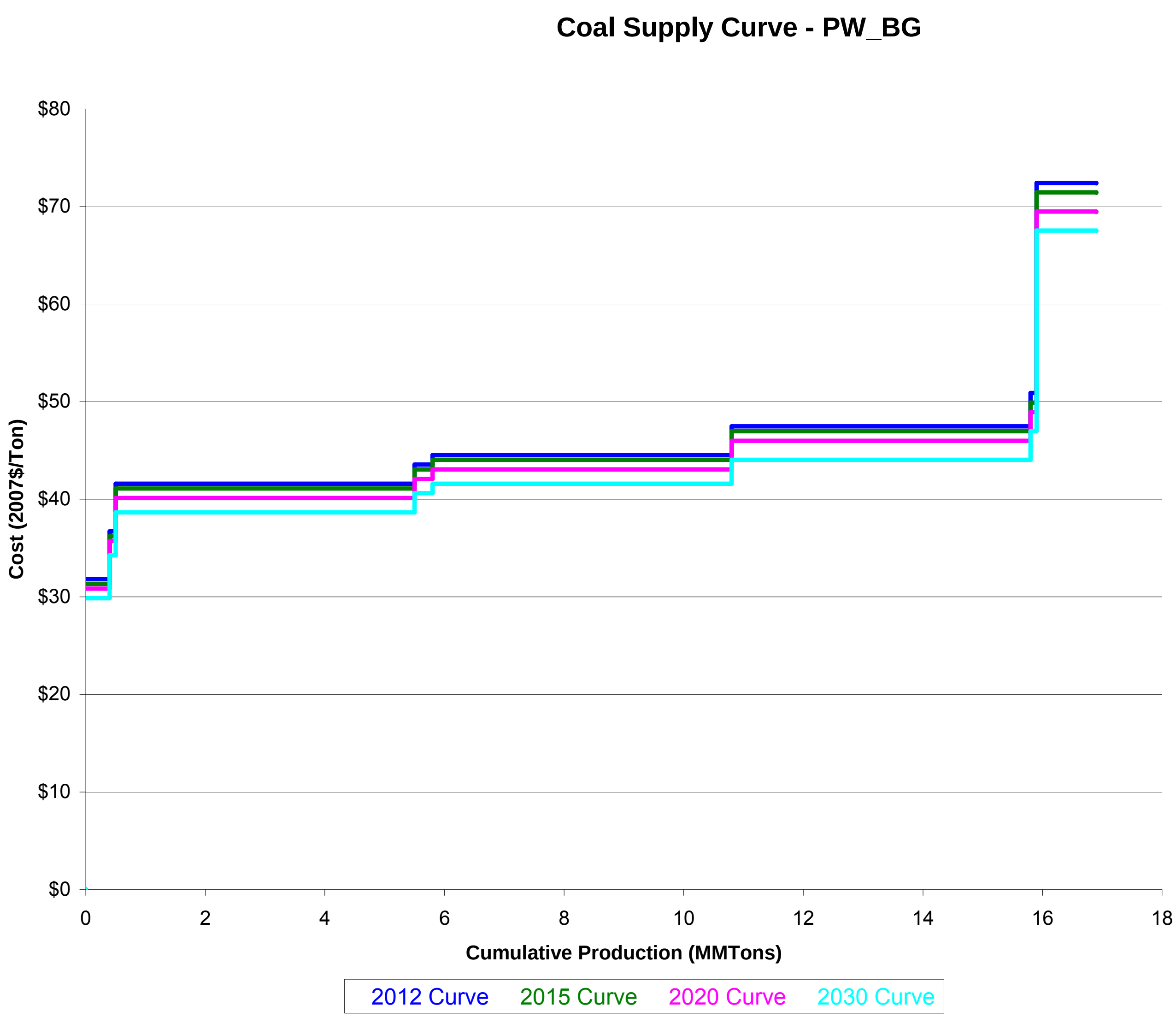
Coal Supply Curve - PC_BH
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

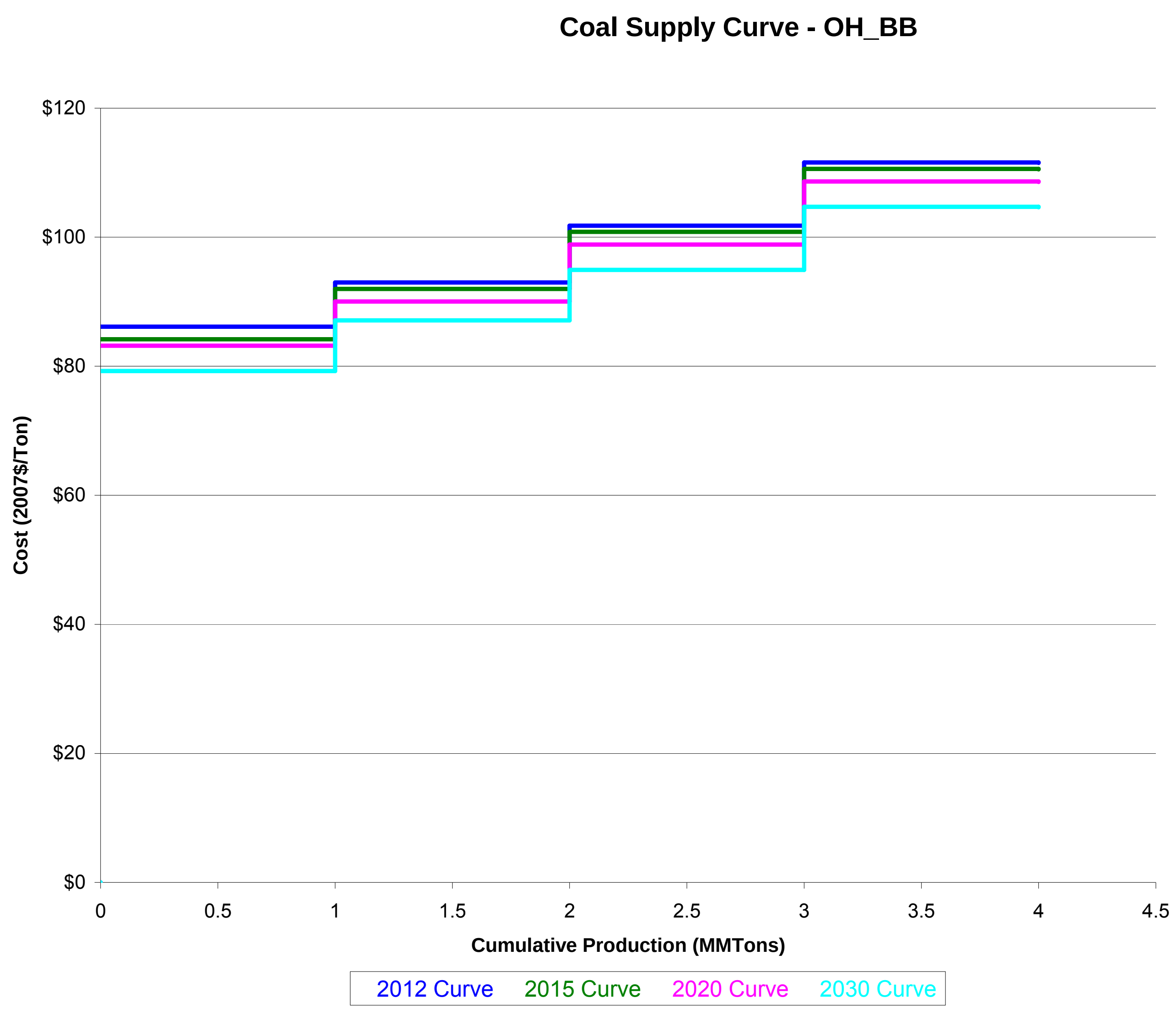


Coal Supply Curve - PW_BD
Cost (2007$/Ton)
$70
$60
$50
$40
$30
$20
$10
$0
0
2
4
6
8
10
12
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

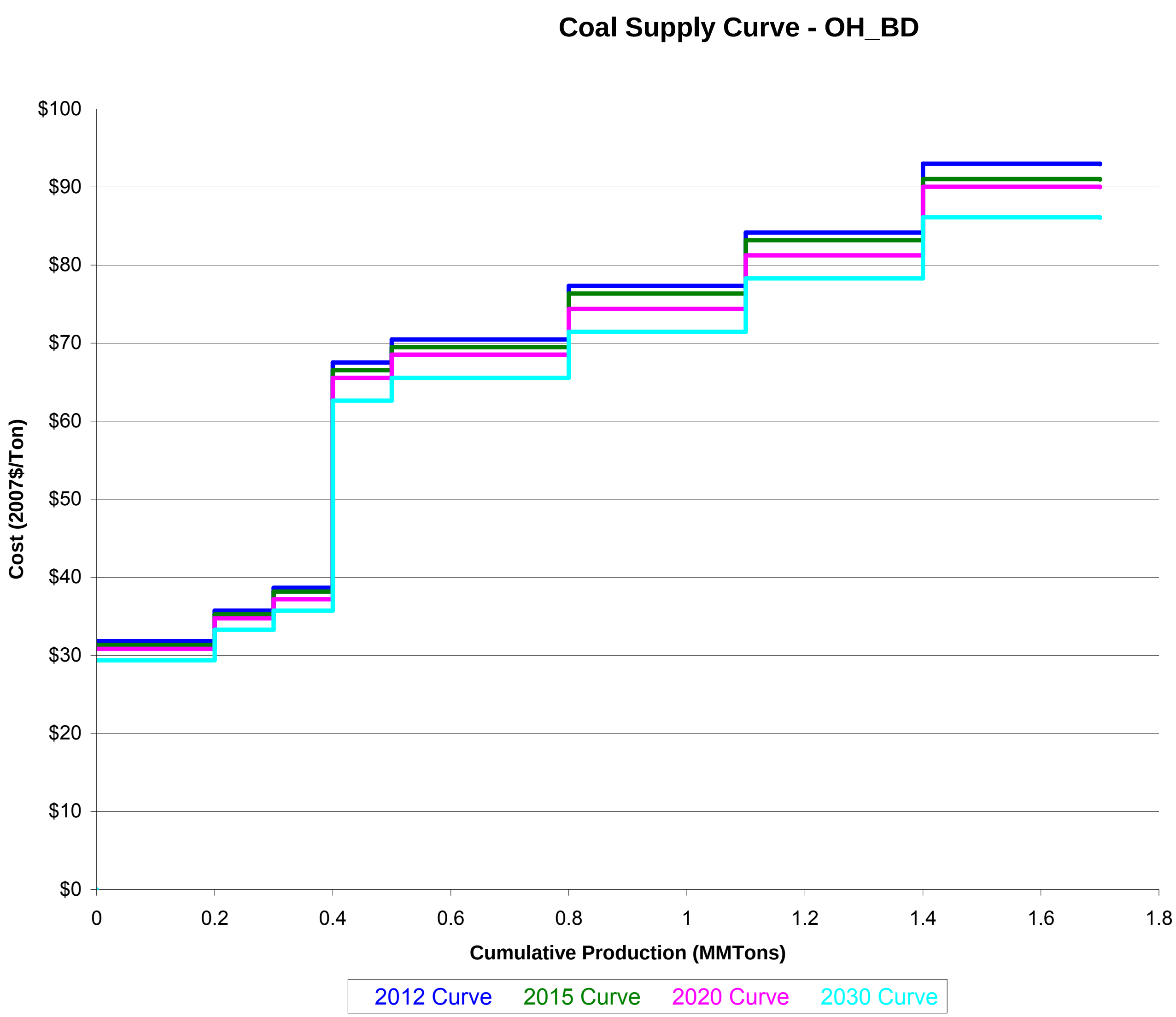


Coal Supply Curve - PW_BE
Cost (2007$/Ton)
$70
$60
$50
$40
$30
$20
$10
$0
0
5
10
15
20
25
30
35
40
45
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

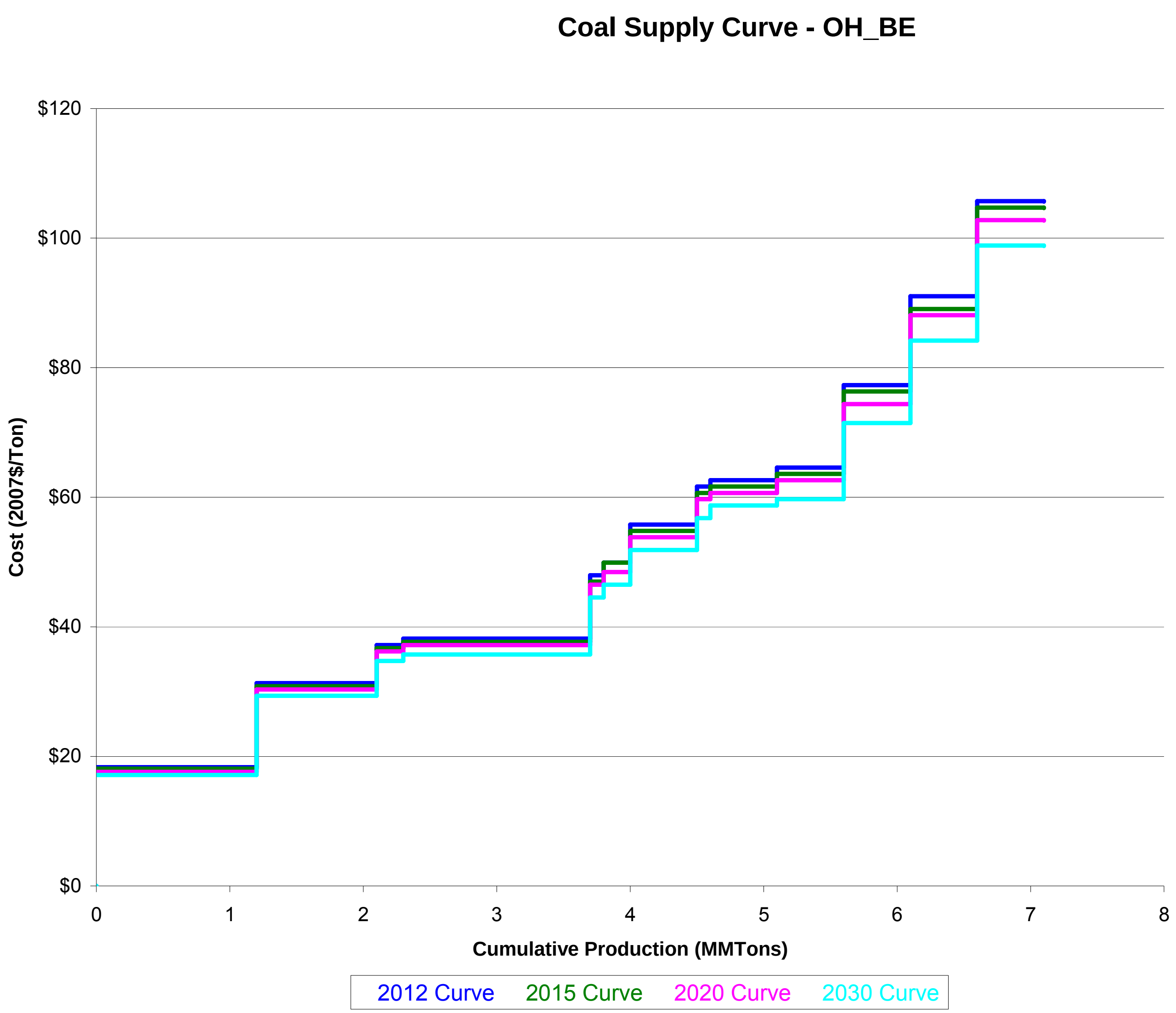

Coal Supply Curve - PW_BG
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

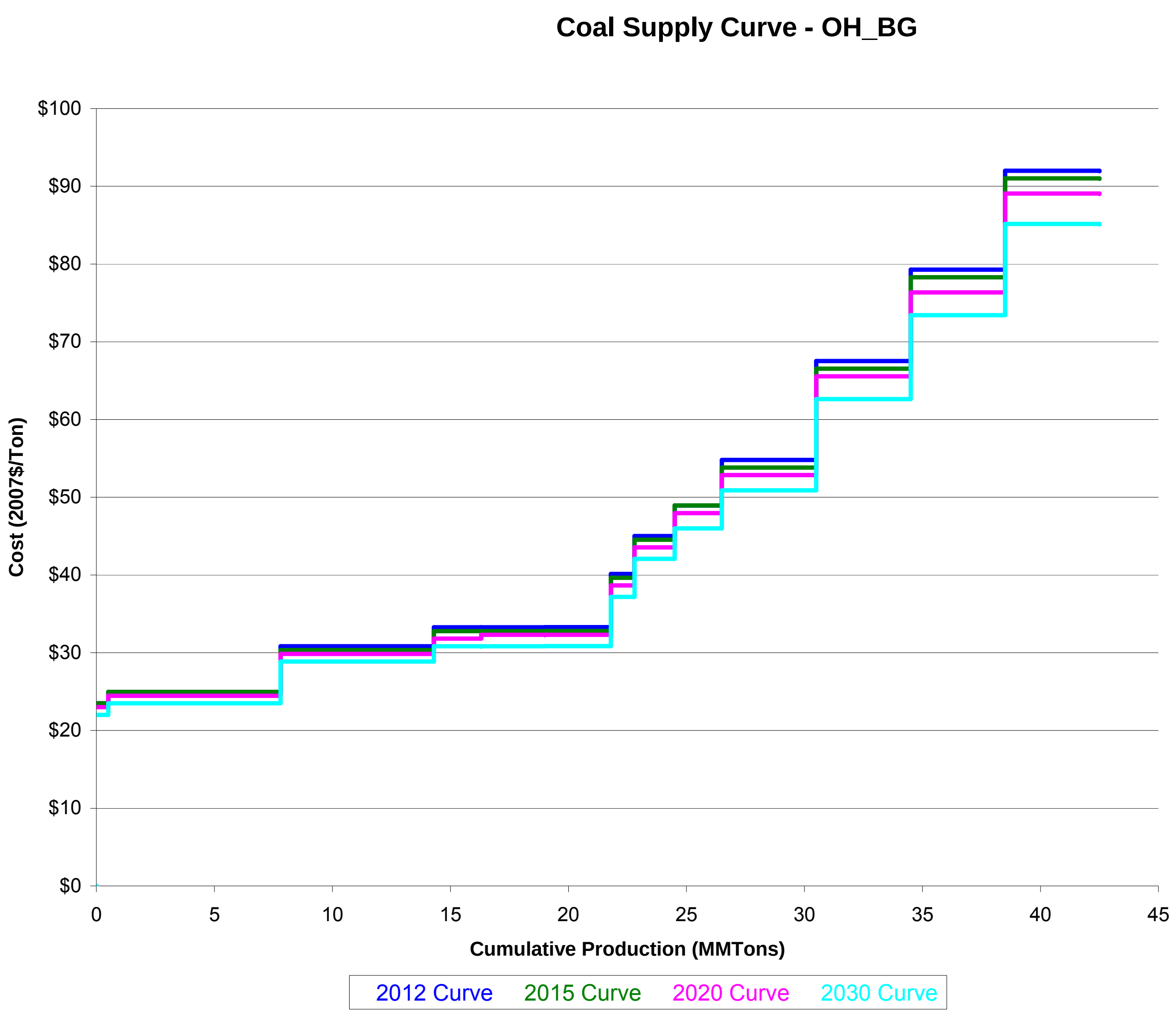


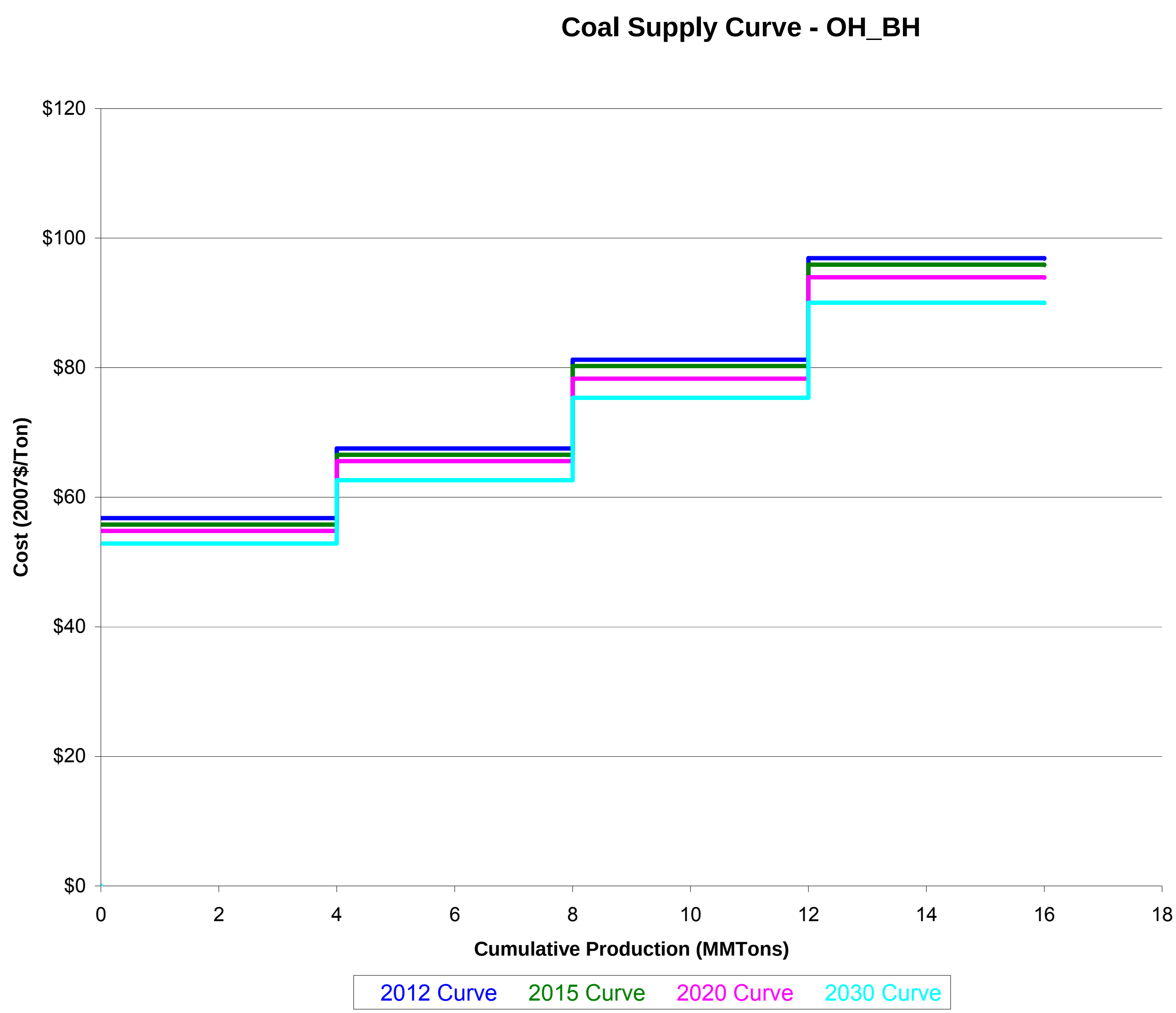
Coal Supply Curve - OH_BB
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

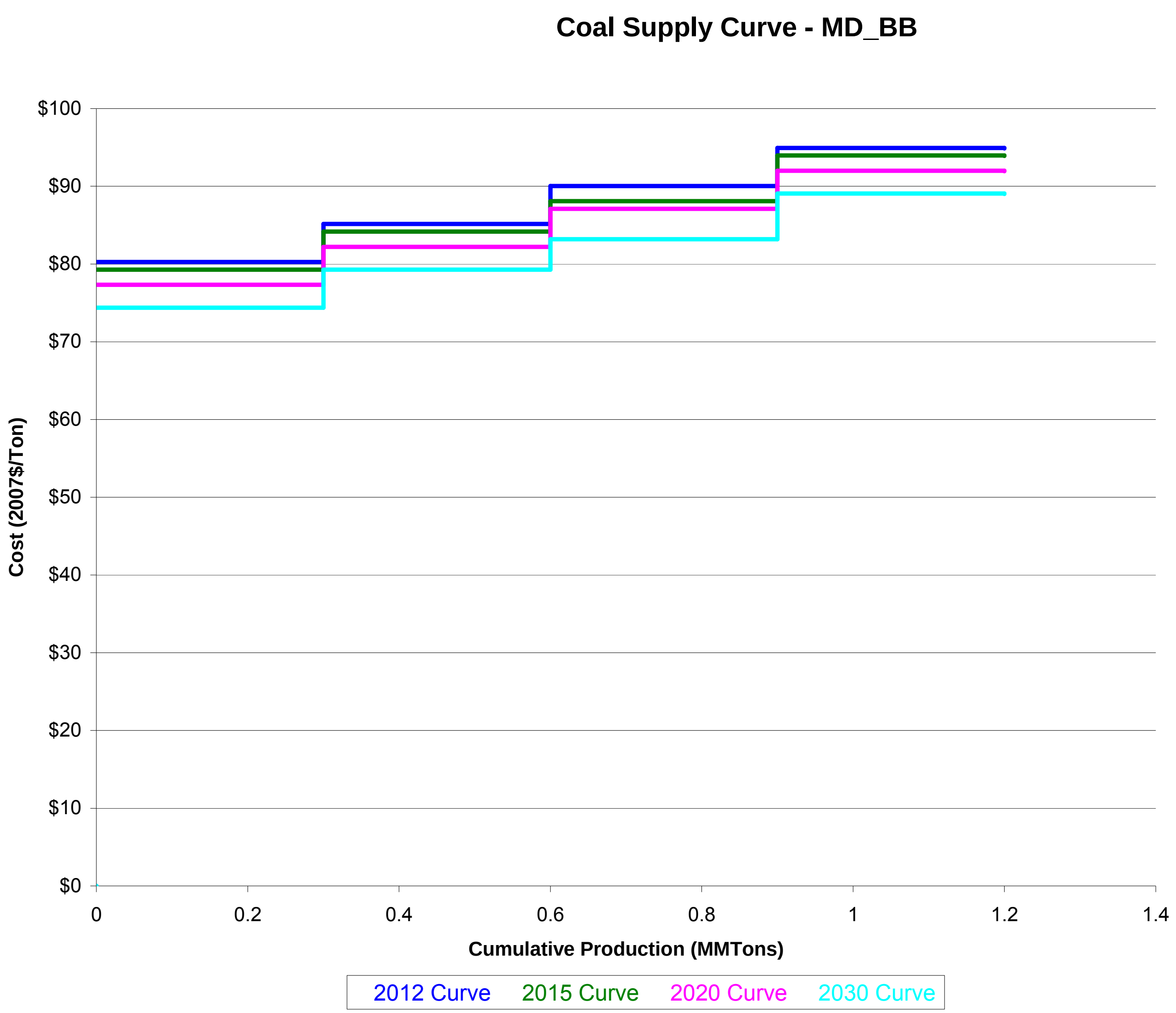


Coal Supply Curve - OH_BD
Cost (2007$/Ton)
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

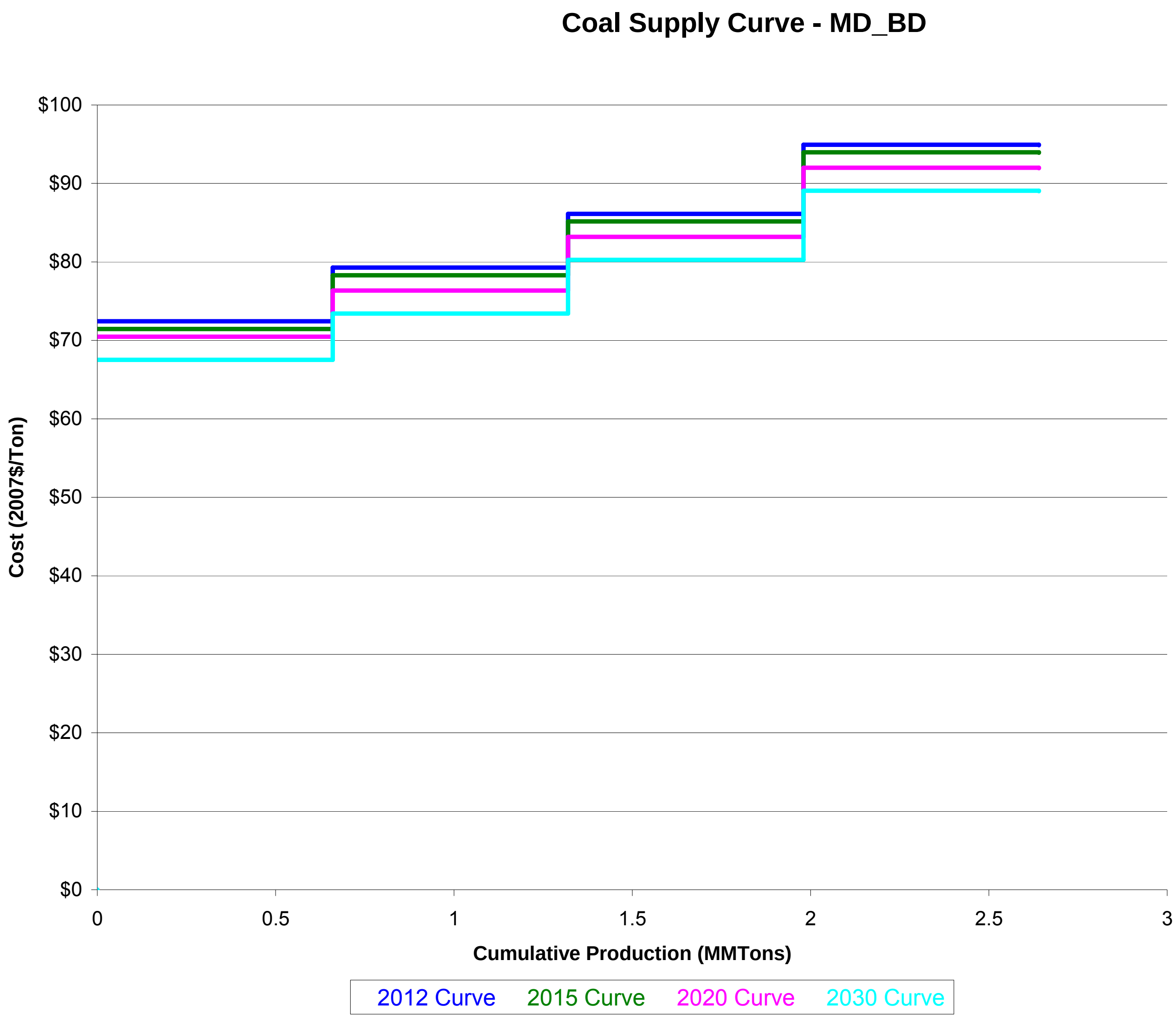

Coal Supply Curve - OH_BE
Cost (2007$/Ton)
$0
$20
$40
$60
$80
$100
$120
0
1
2
3
4
5
6
7
8
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

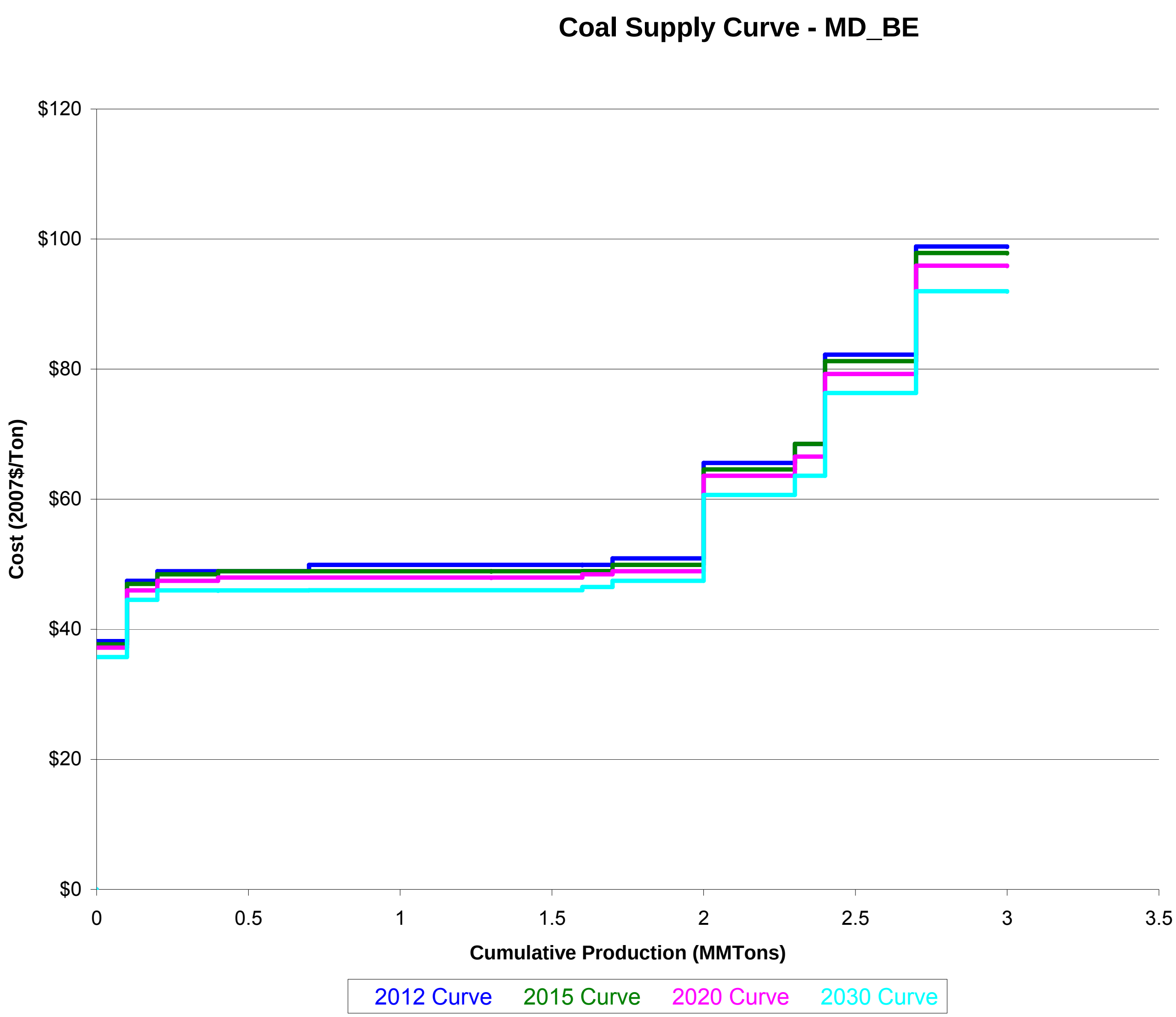

Coal Supply Curve - OH_BG
Cost (2007$/Ton)
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
0
5
10
15
20
25
30
35
40
45
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - OH_BH
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

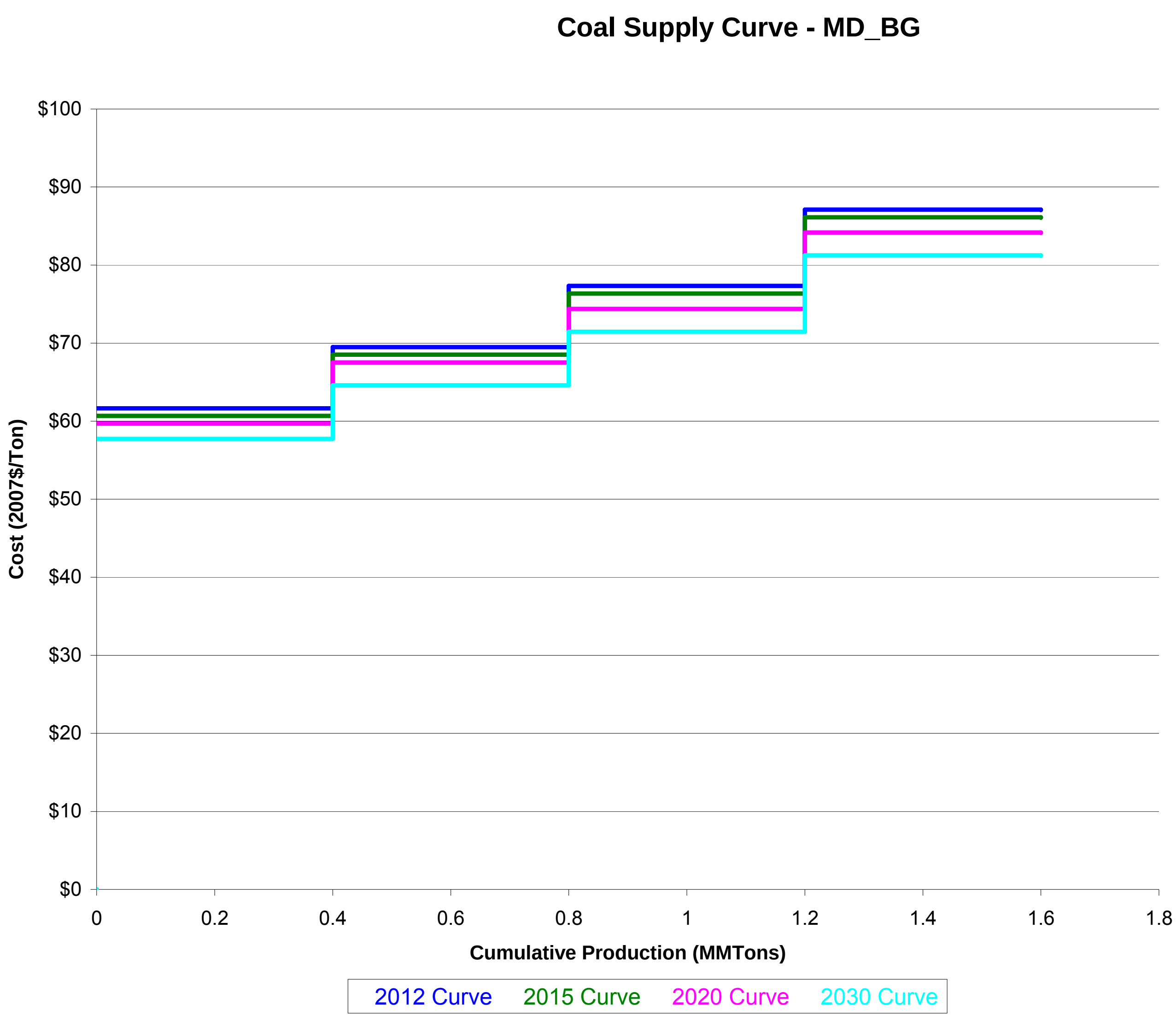


Coal Supply Curve - MD_BB
Cost (2007$/Ton)
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

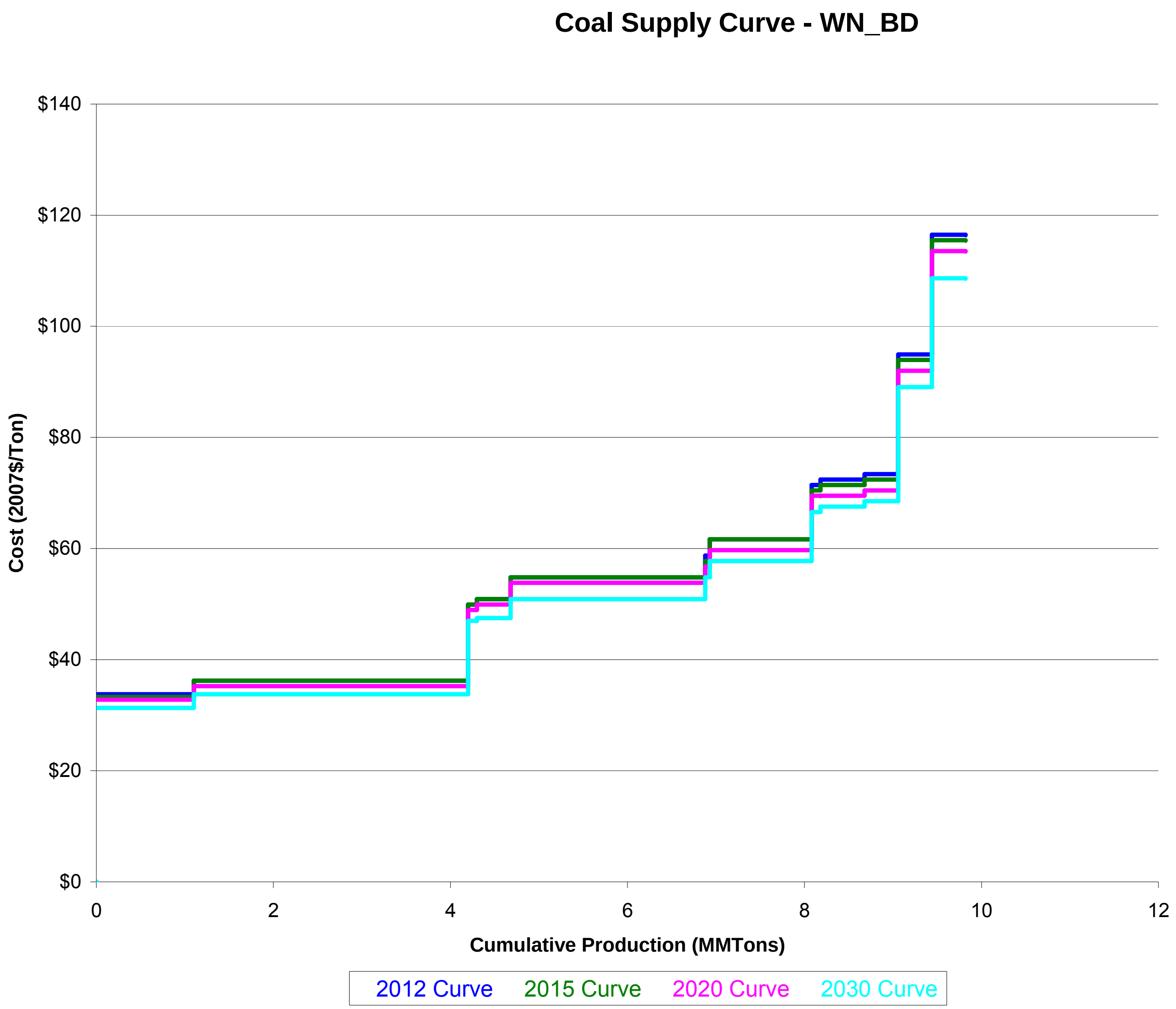

Coal Supply Curve - MD_BD
Cost (2007$/Ton)
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
0
0.5
1
1.5
2
2.5
3
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

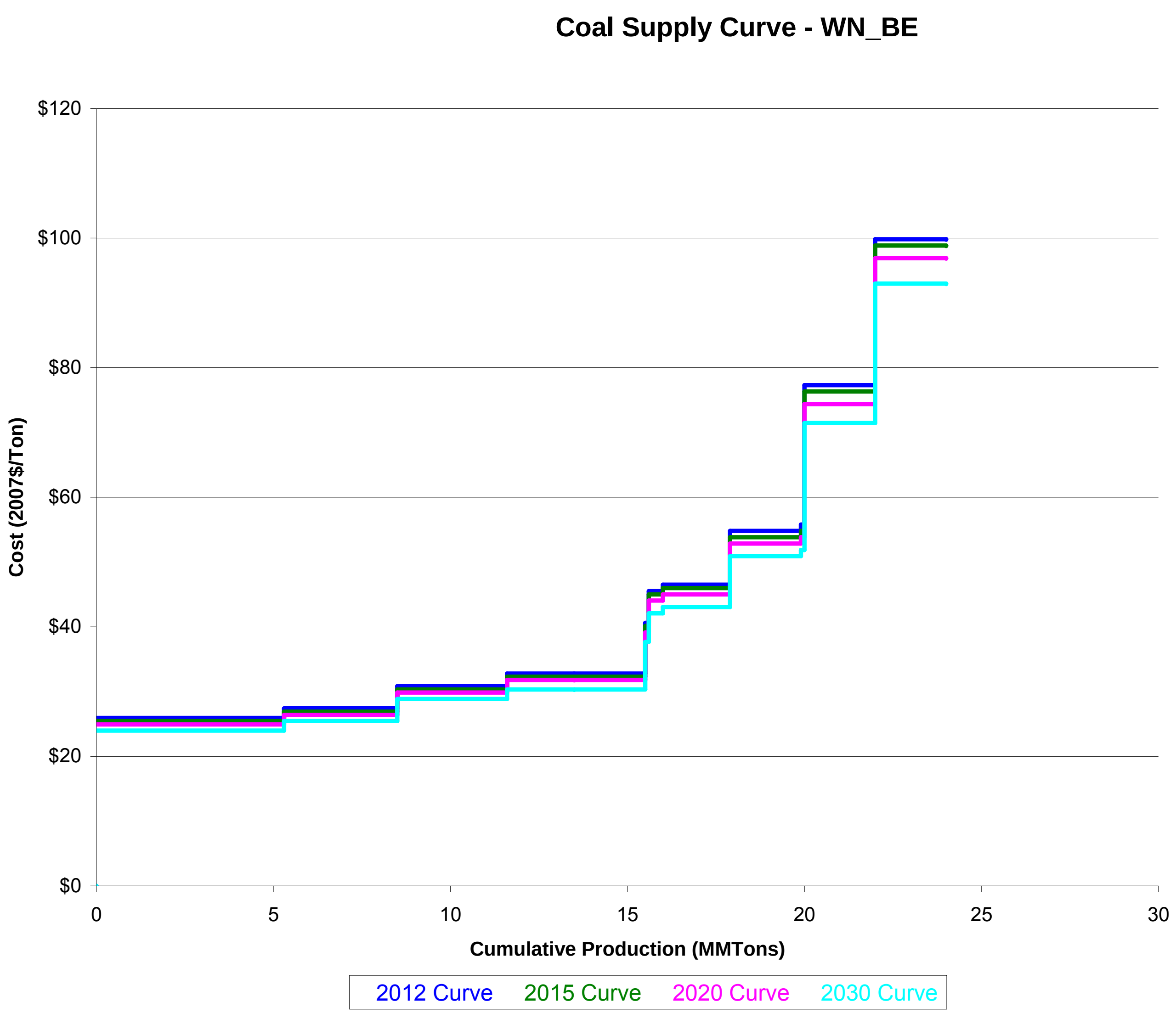


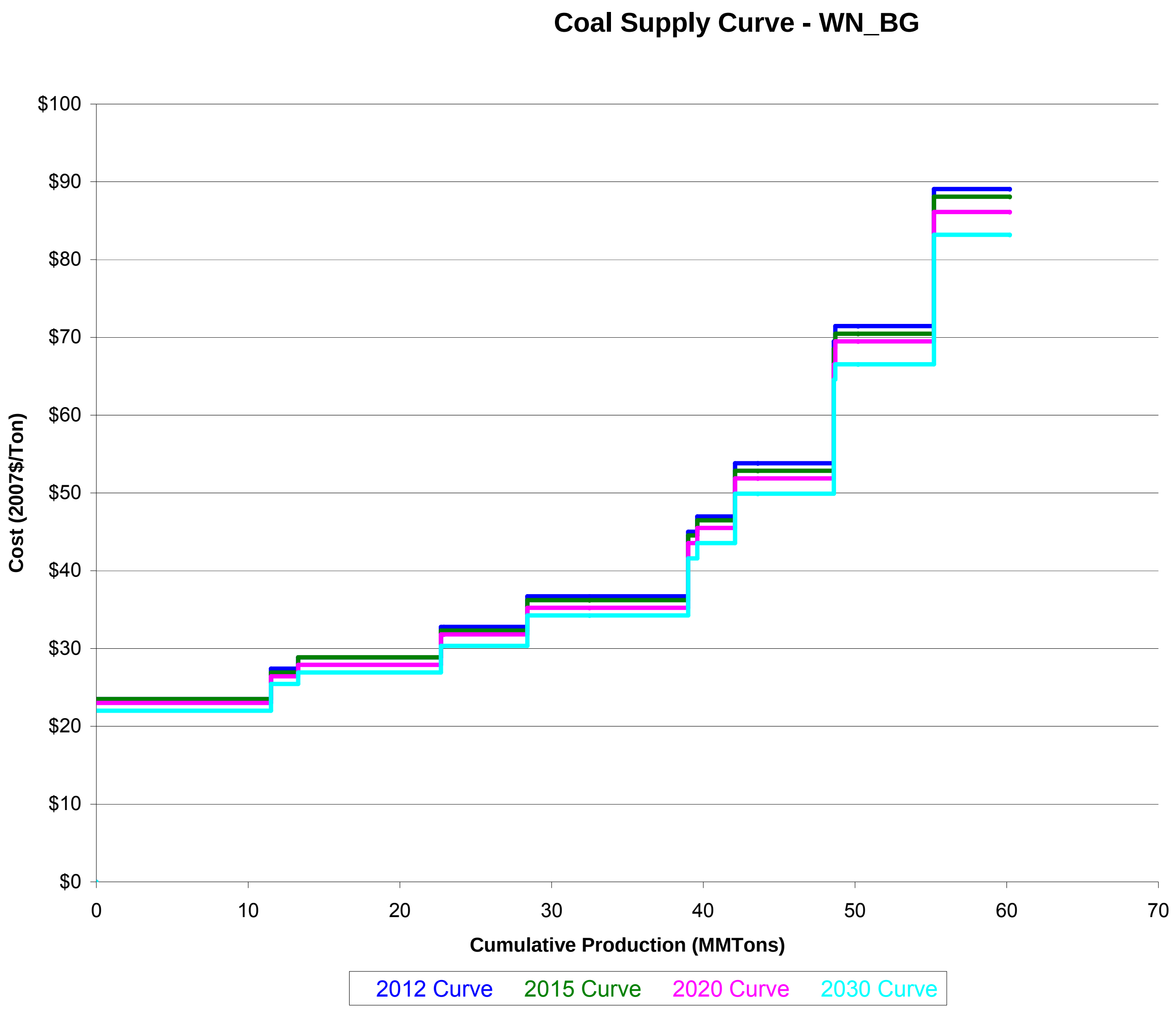
Coal Supply Curve - MD_BE
Cost (2007$/Ton)
$120
$100
$80
$60
$40
$20
$0
0
0.5
1
1.5
2
2.5
3
3.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

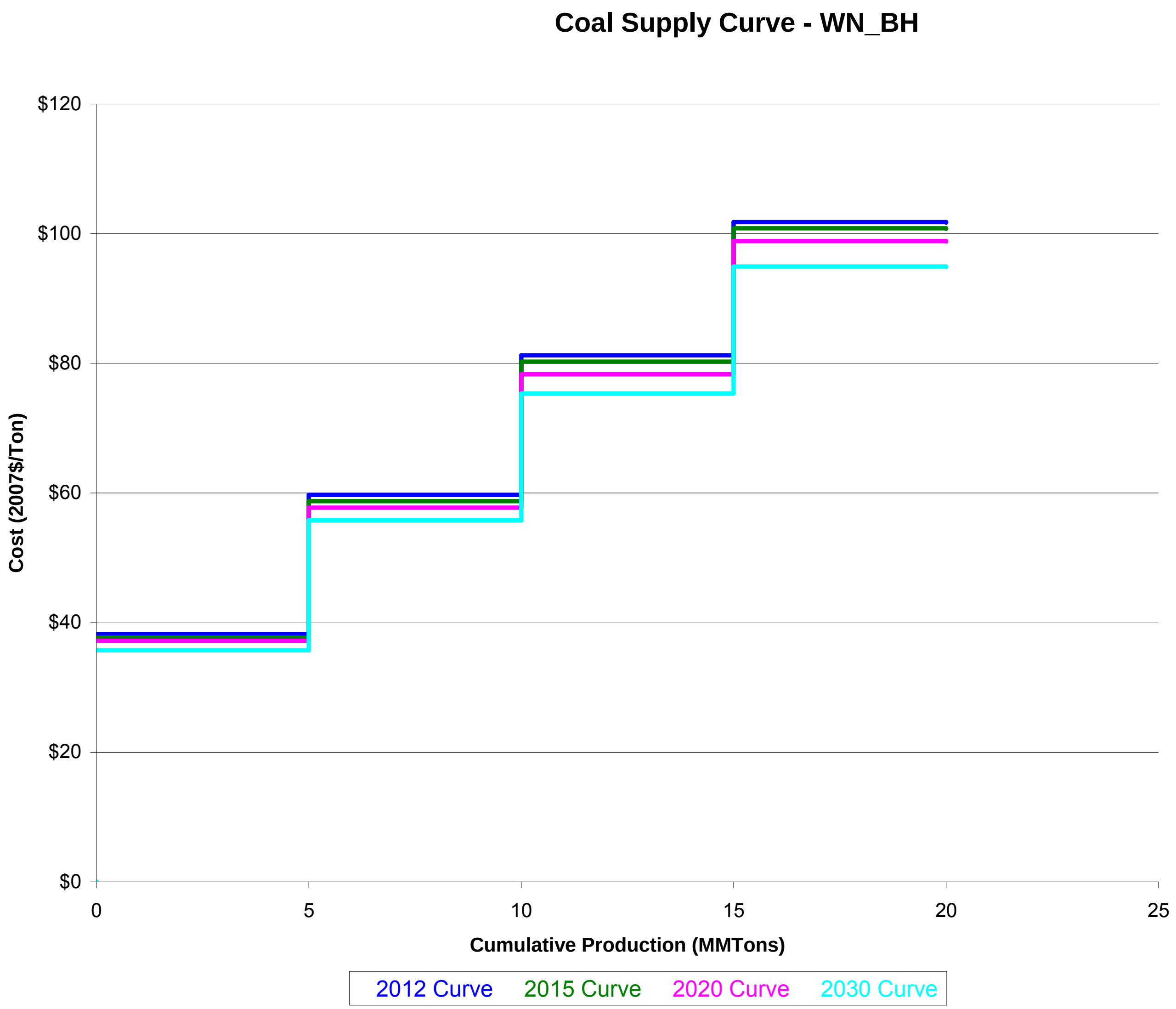


Coal Supply Curve - MD_BG
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

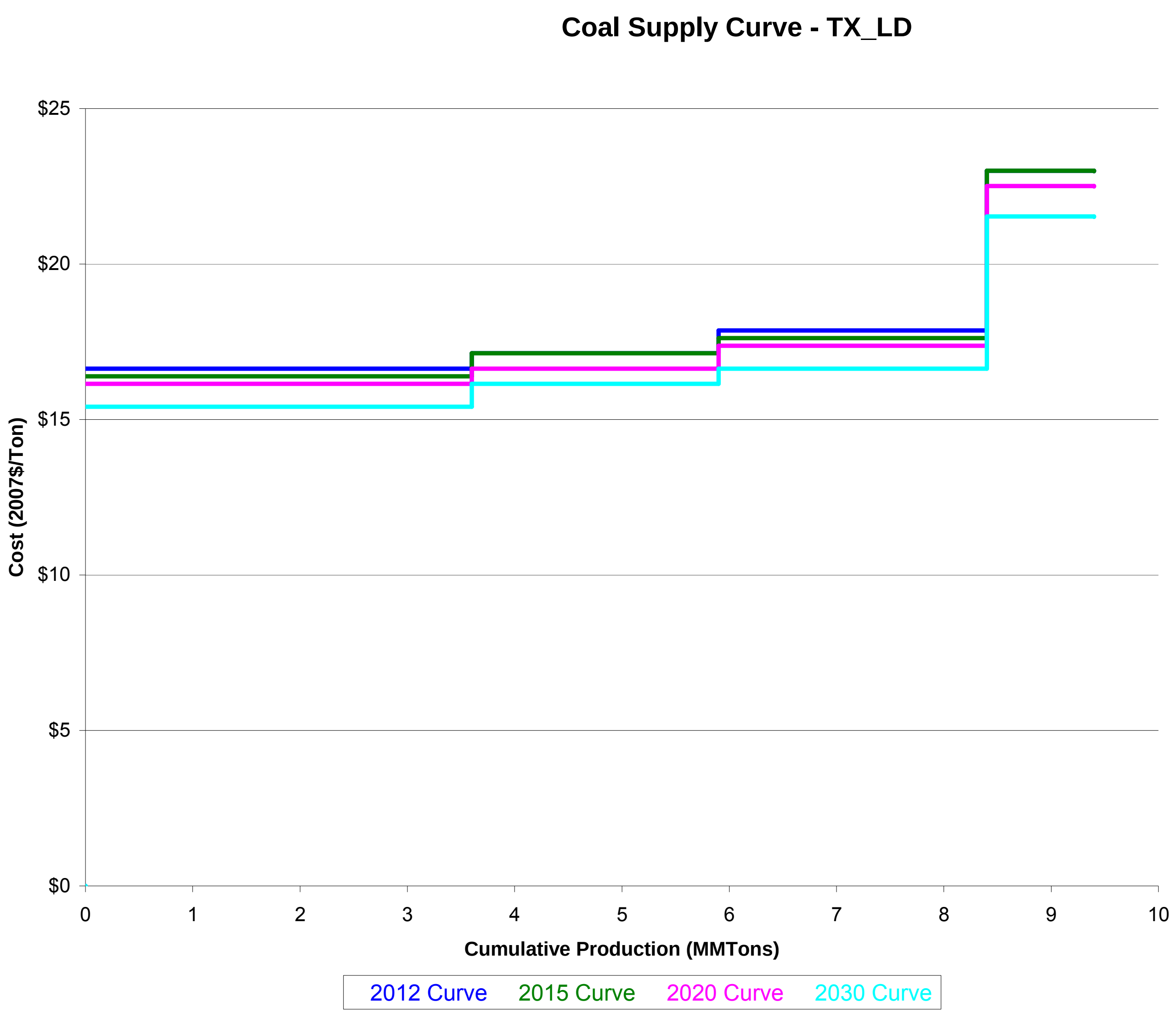

Coal Supply Curve - WN_BD
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - WN_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

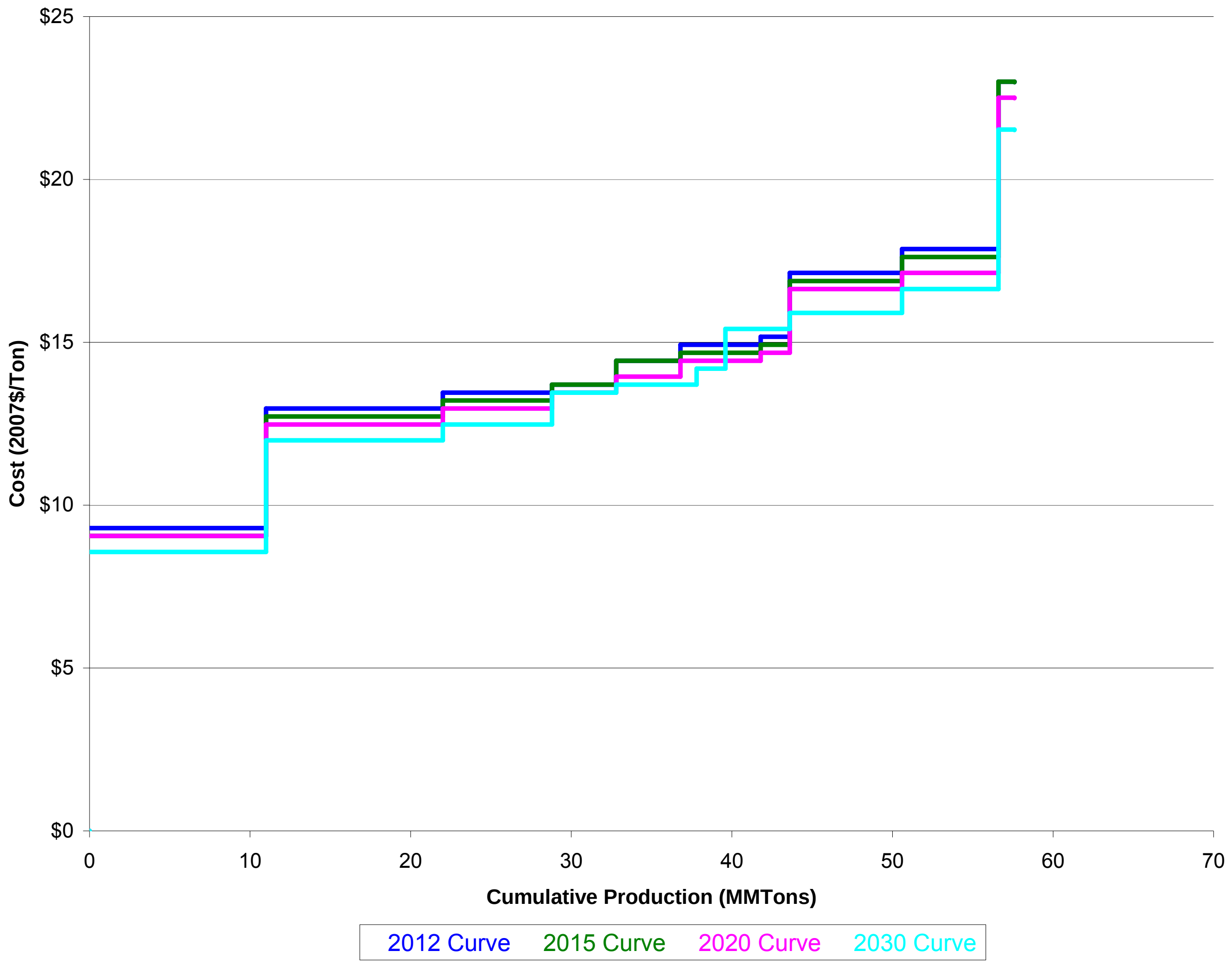

Coal Supply Curve - WN_BG
Cost (2007$/Ton)
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
0
10
20
30
40
50
60
70
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

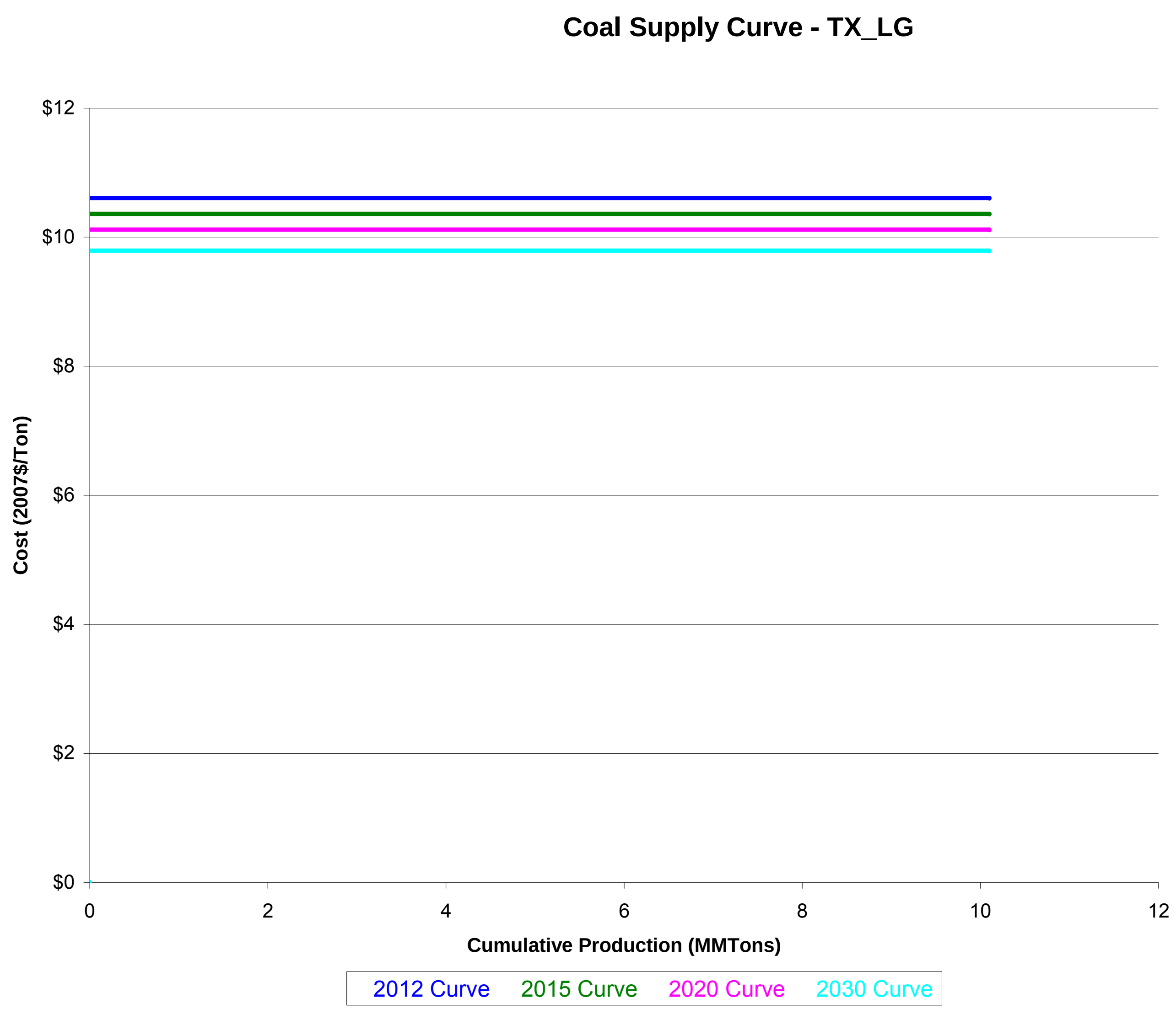


Coal Supply Curve - WN_BH
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

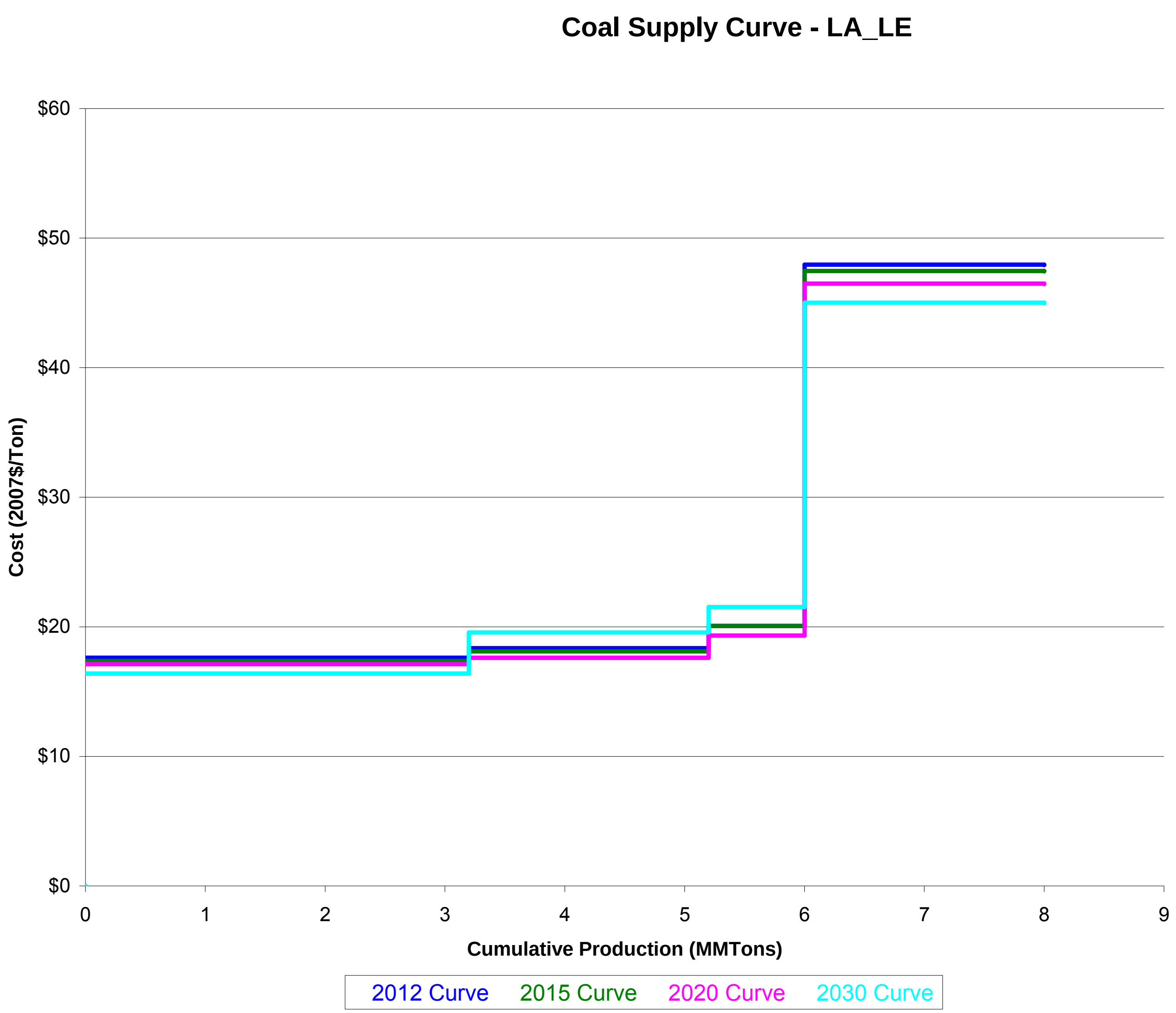

Coal Supply Curve - TX_LD
Cost (2007$/Ton)
$25
$20
$15
$10
$5
$0
0
1
2
3
4
5
6
7
8
9
10
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

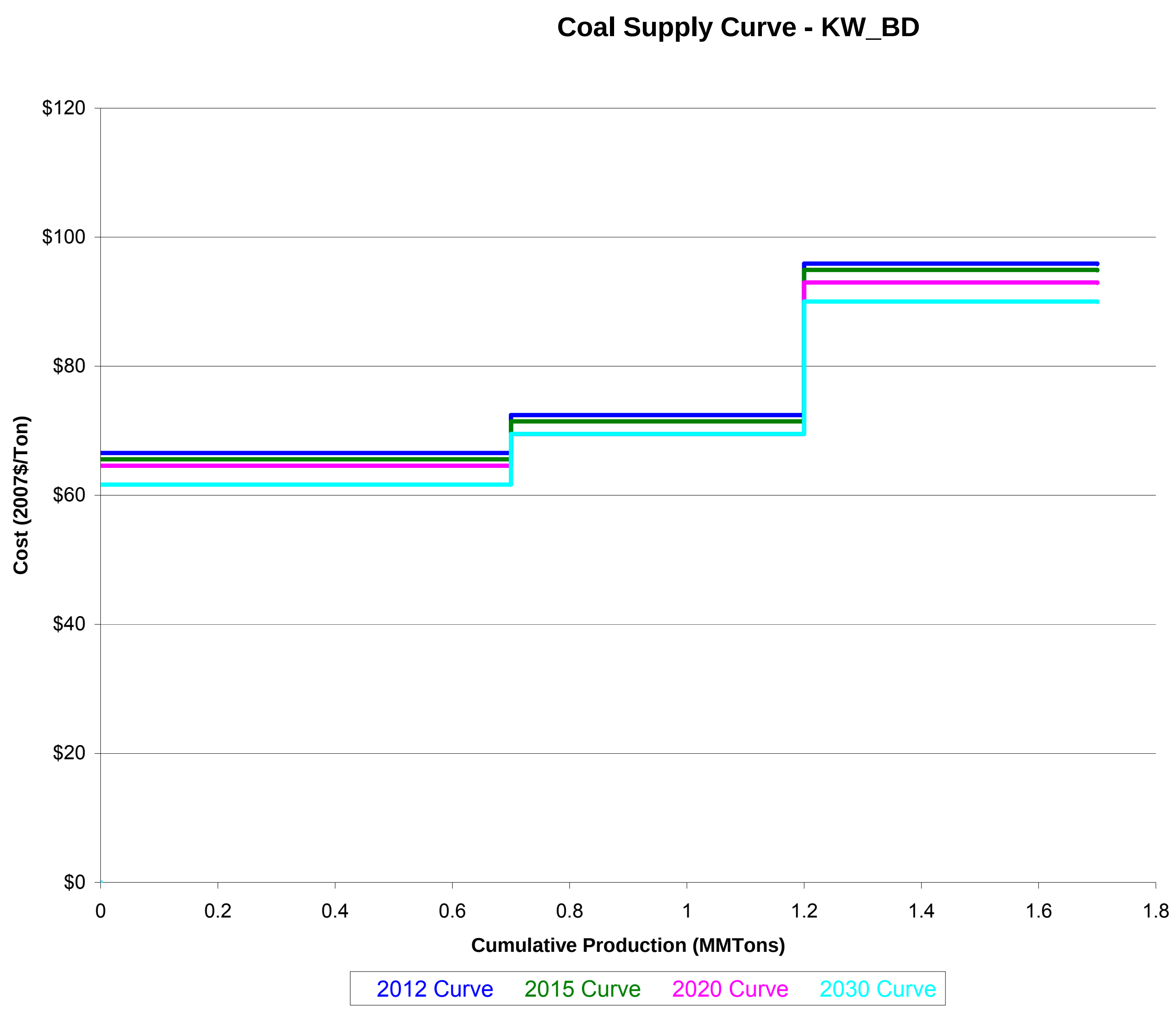
Coal Supply Curve - TX_LE



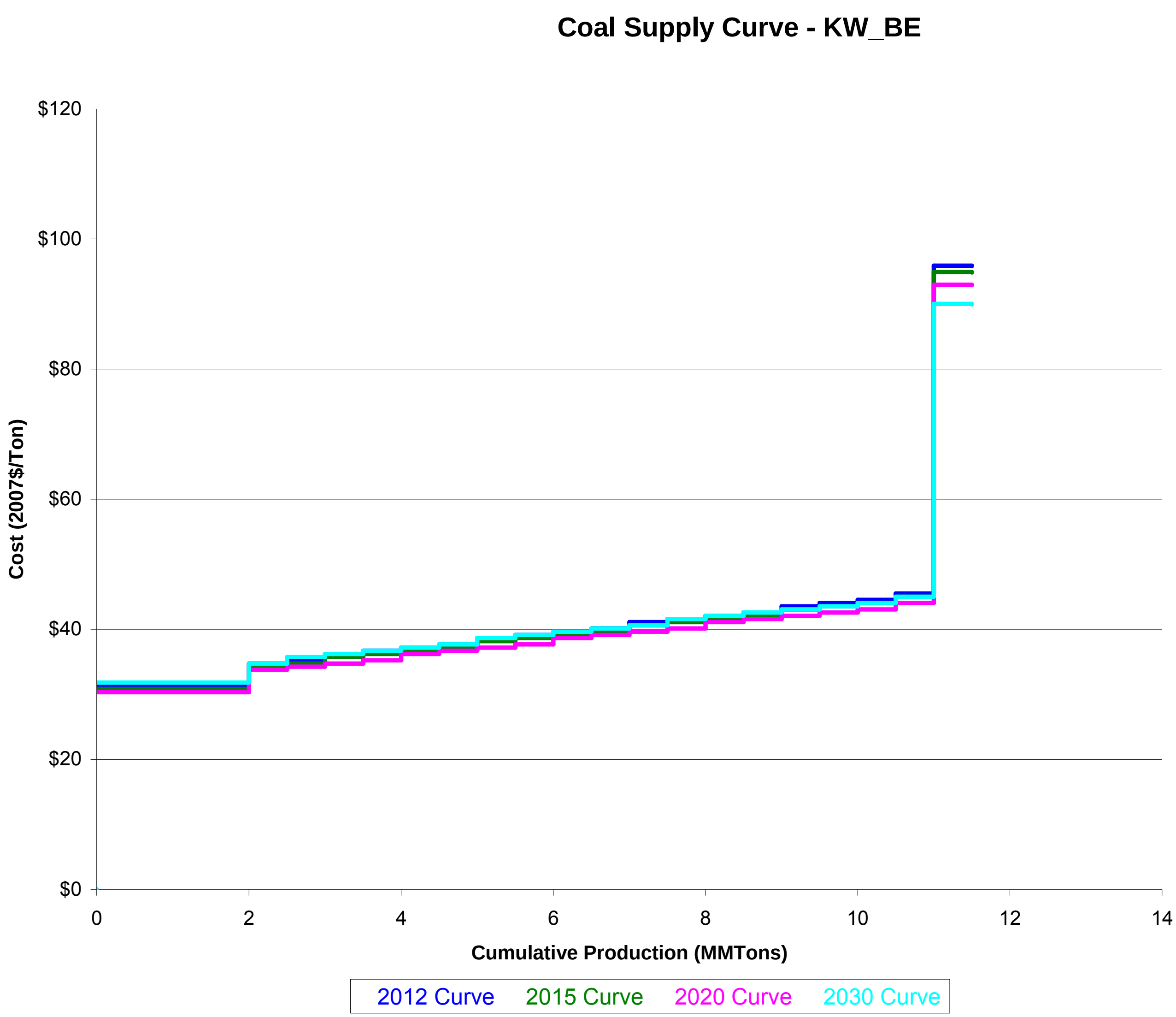


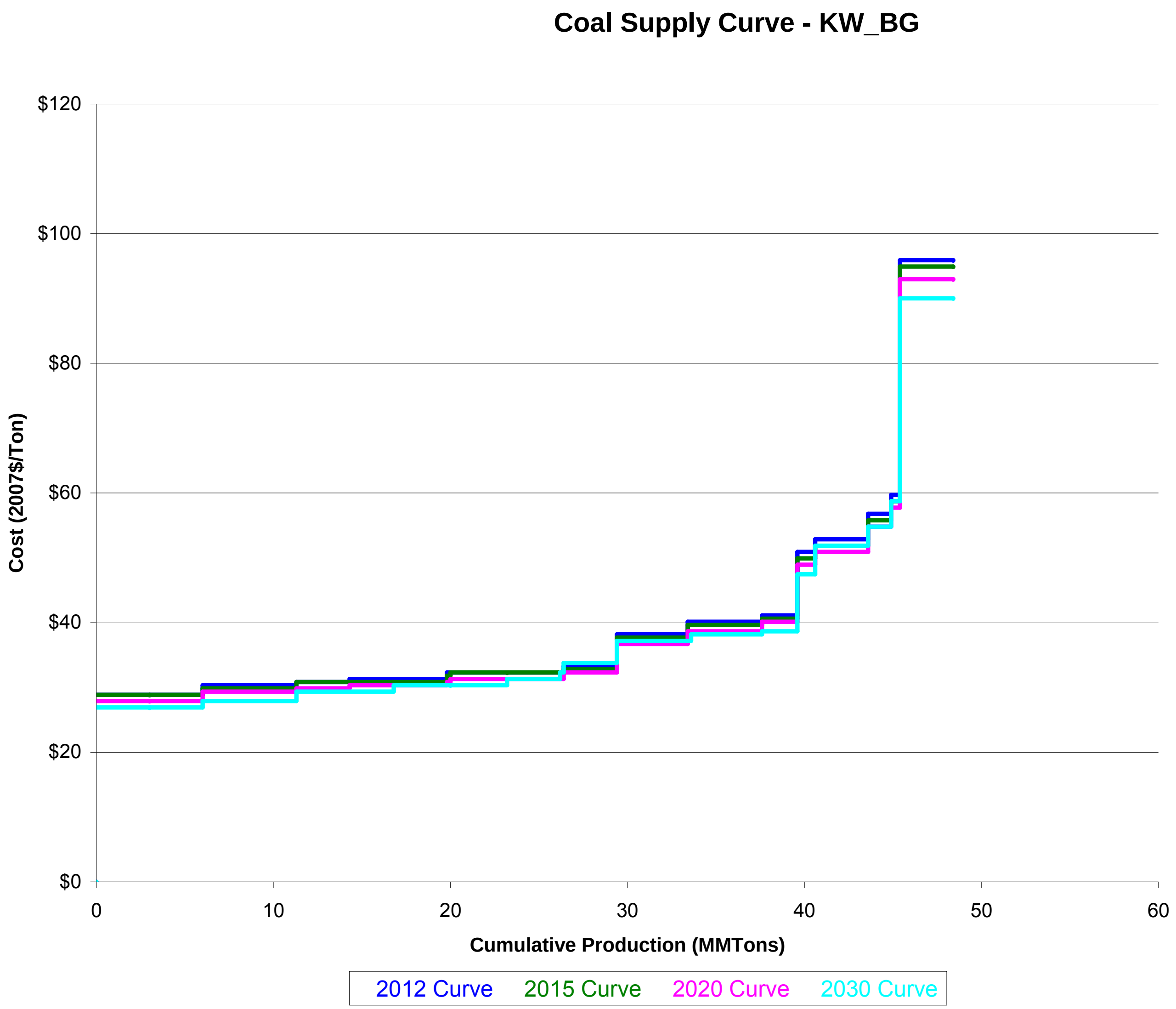
Coal Supply Curve - TX_LG
Cost (2007$/Ton)
$12
$10
$8
$6
$4
$2
$0
0
2
4
6
8
10
12
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

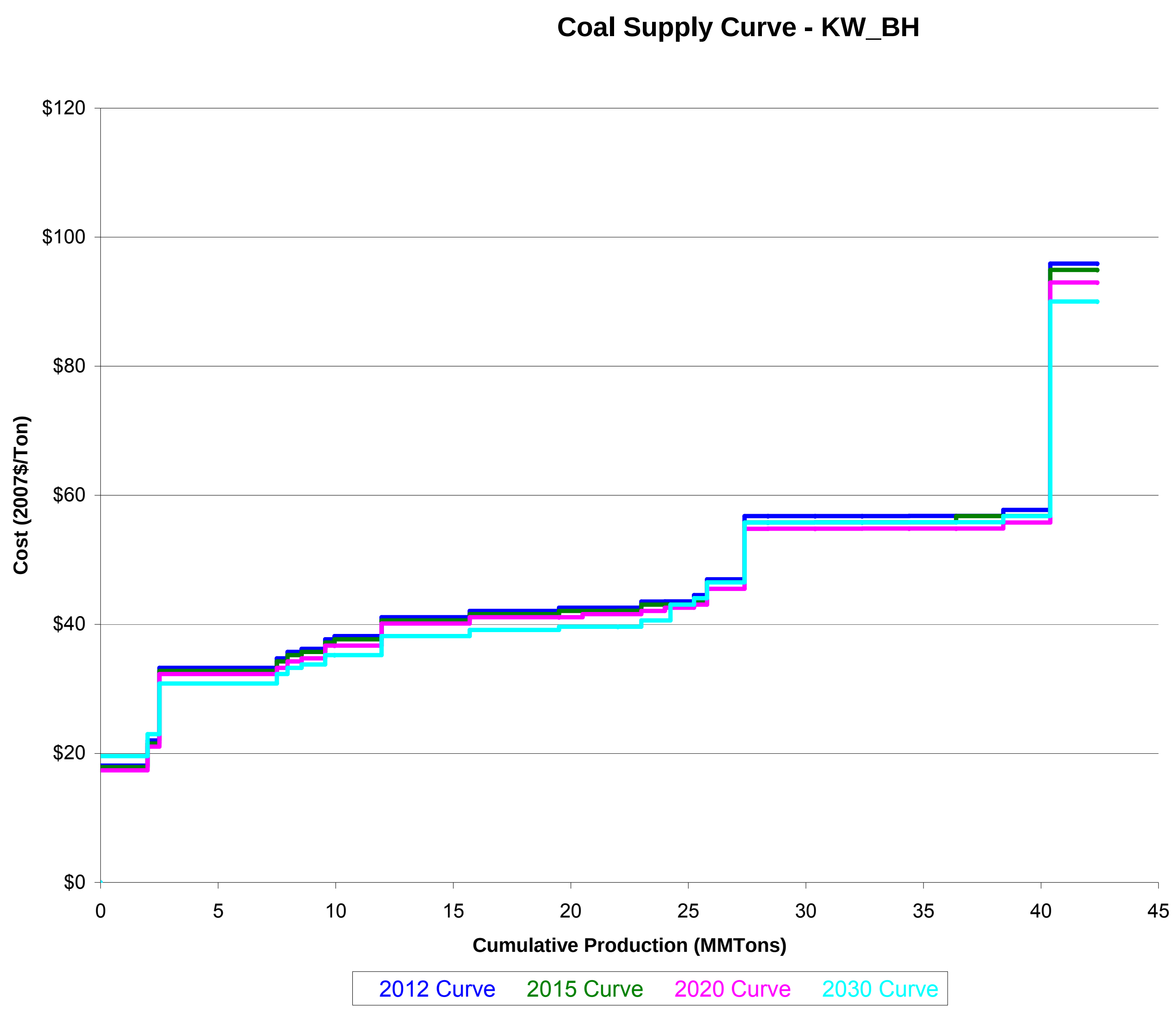

Coal Supply Curve - LA_LE
Cost (2007$/Ton)
$0
$10
$20
$30
$40
$50
$60
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

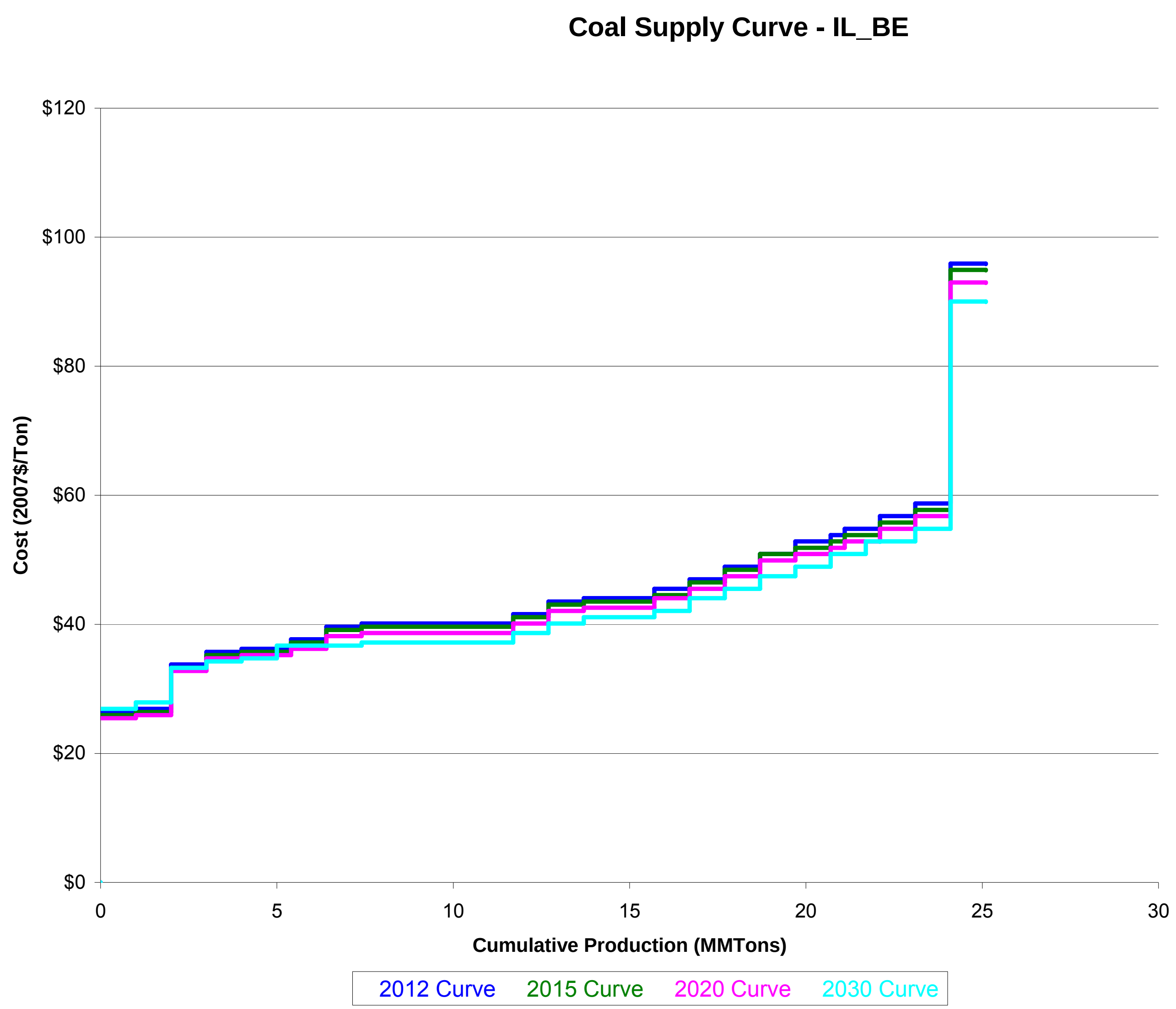


Coal Supply Curve - KW_BD
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

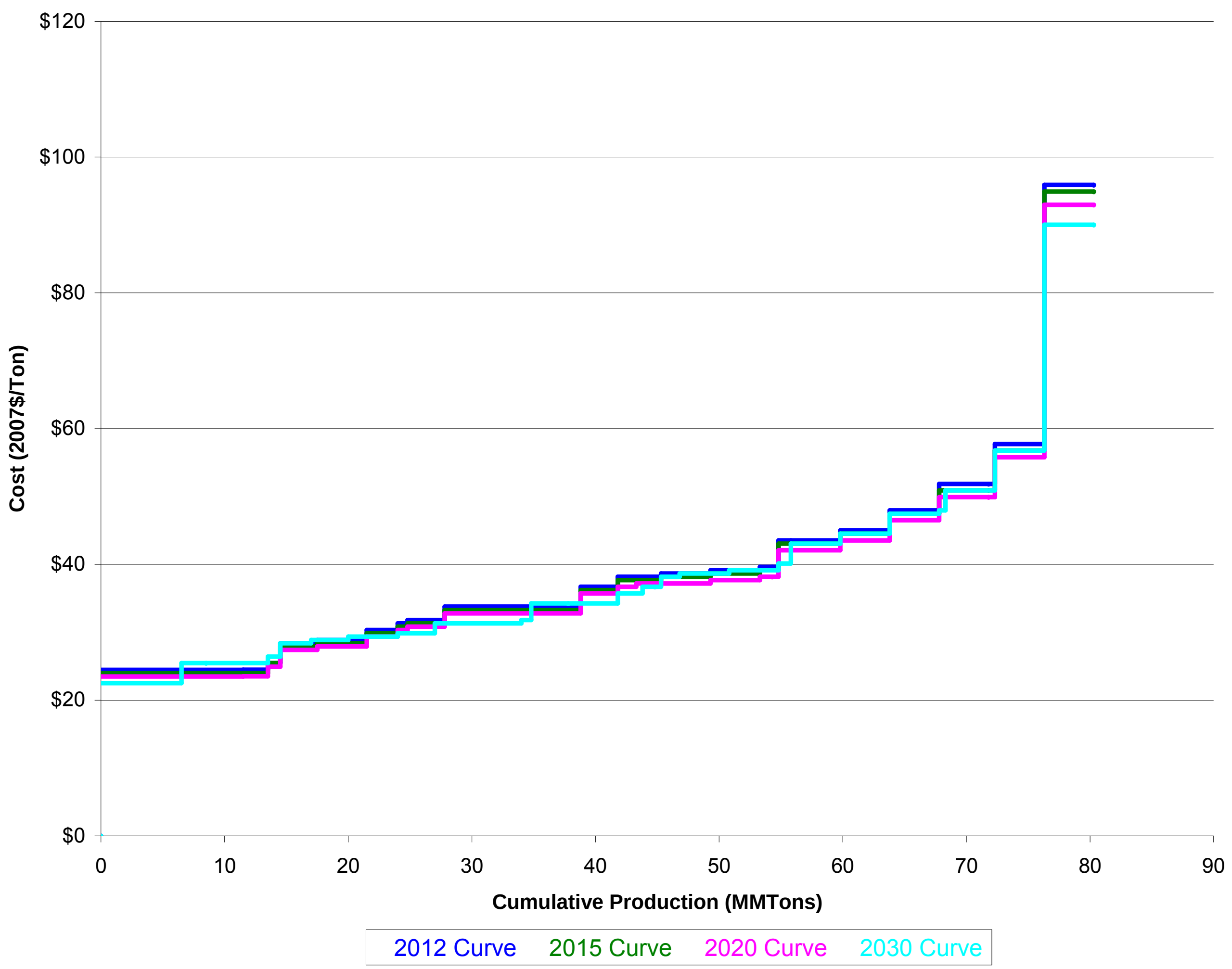

Coal Supply Curve - KW_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - KW_BG
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

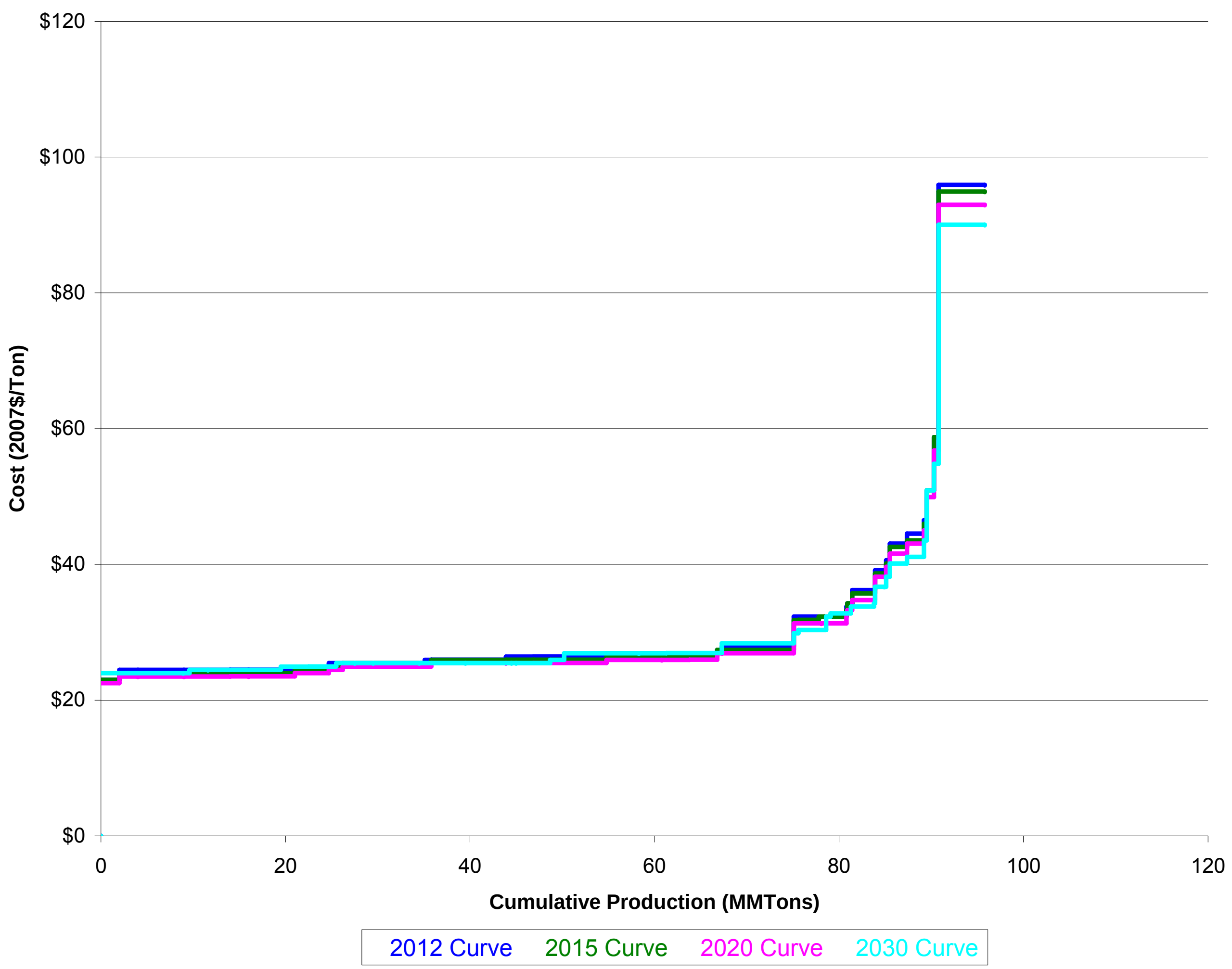

Coal Supply Curve - KW_BH
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
35
40
45
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

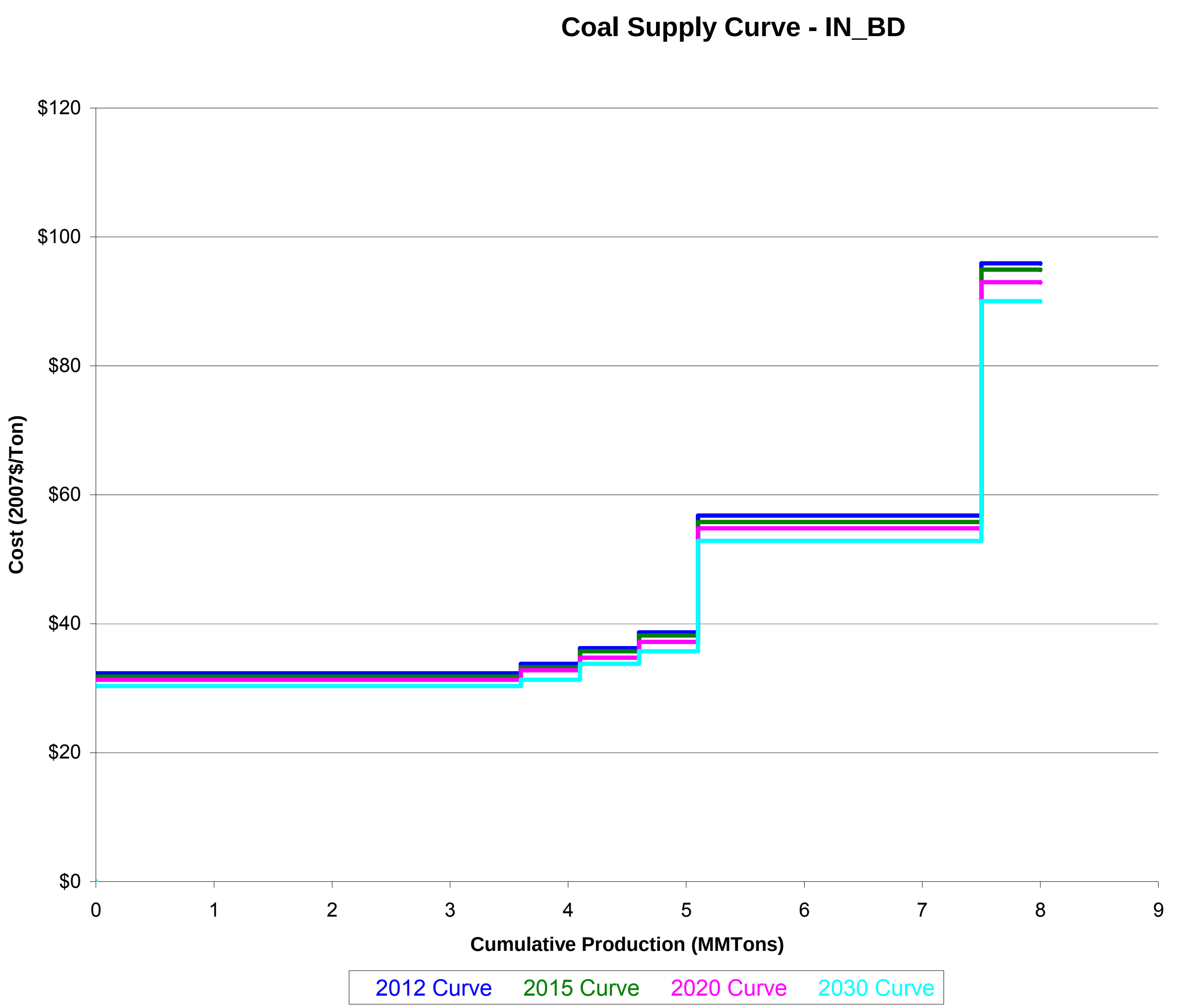

Coal Supply Curve - IL_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

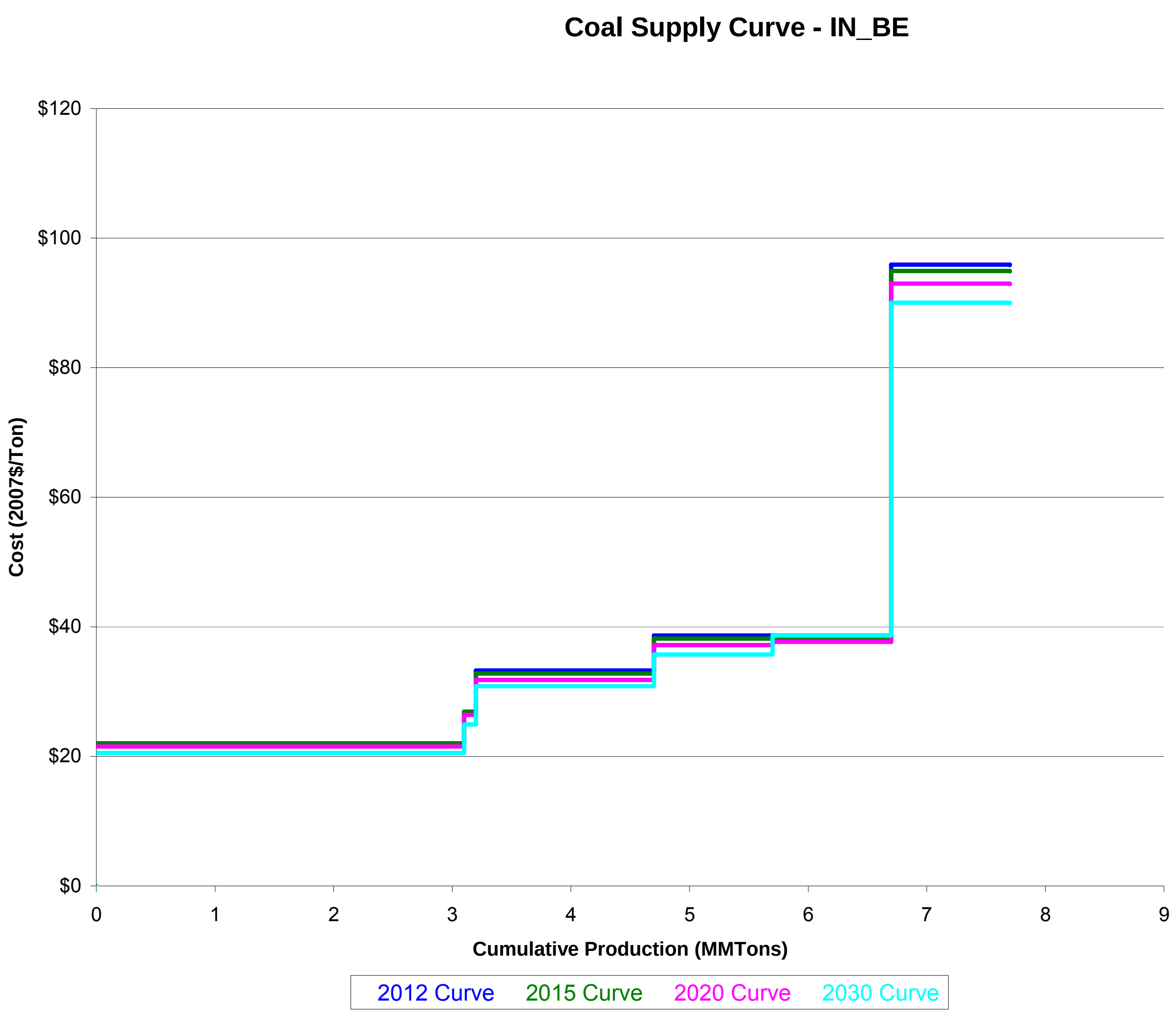
Coal Supply Curve - IL_BG

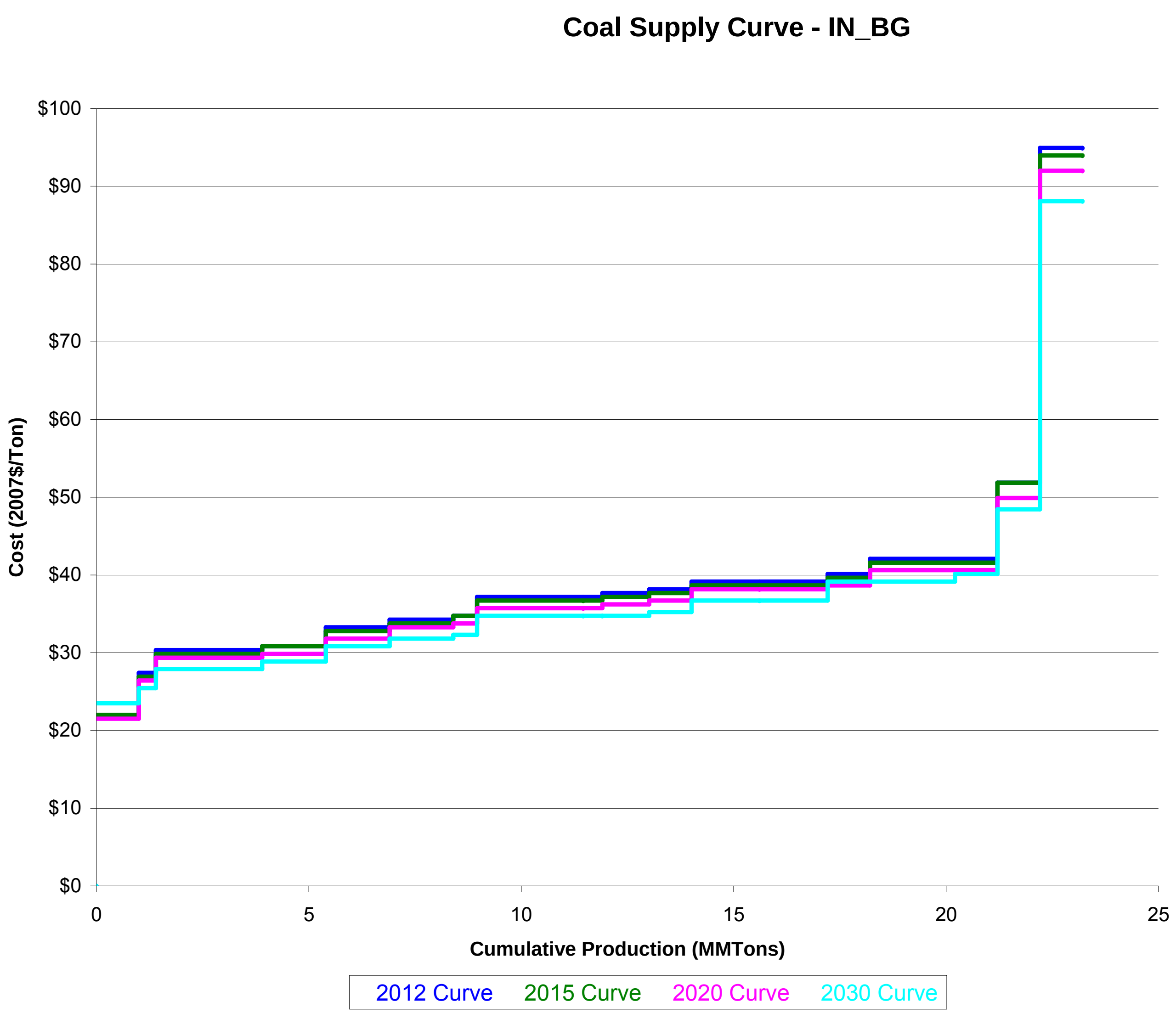


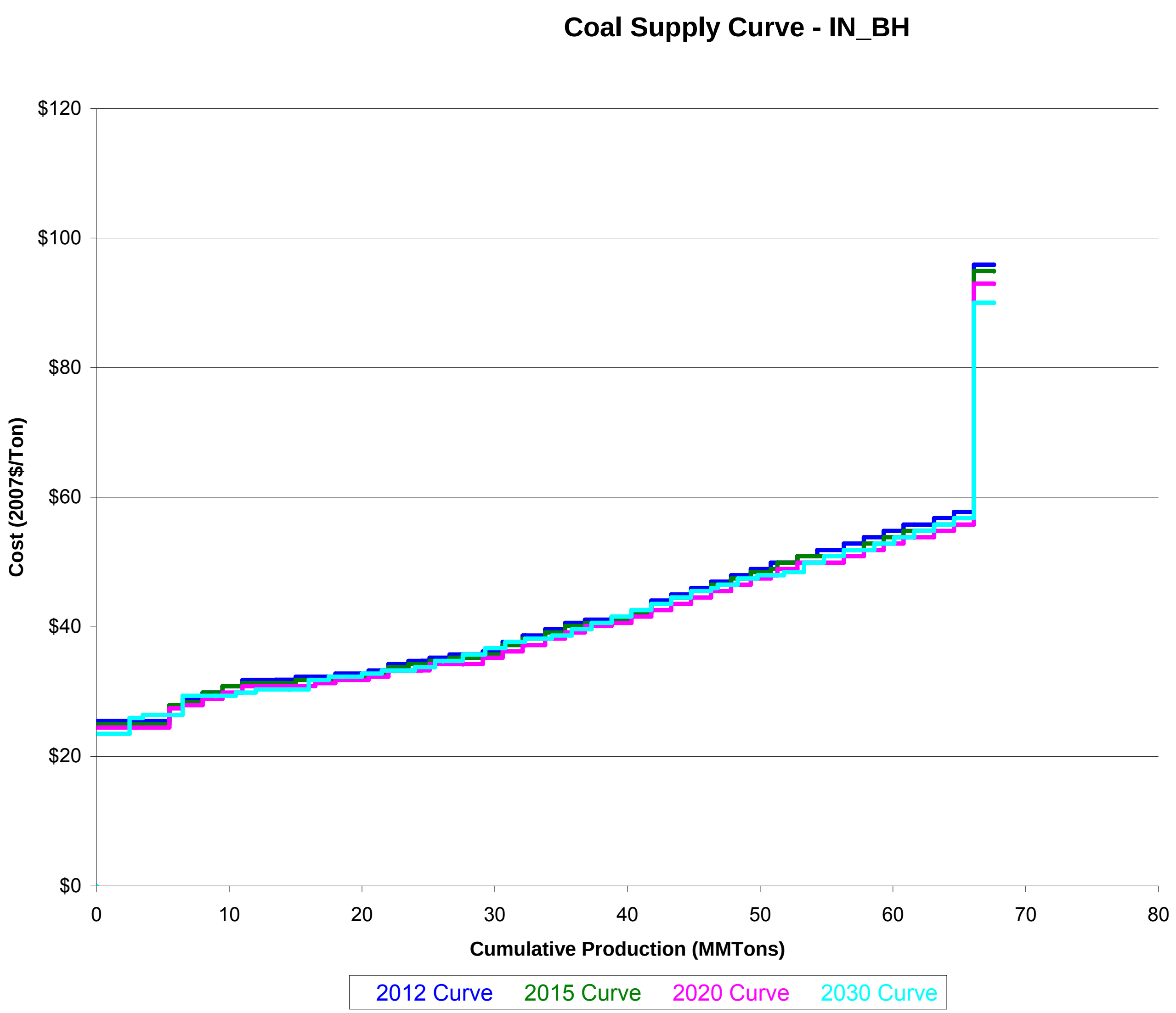
Coal Supply Curve - IL_BH

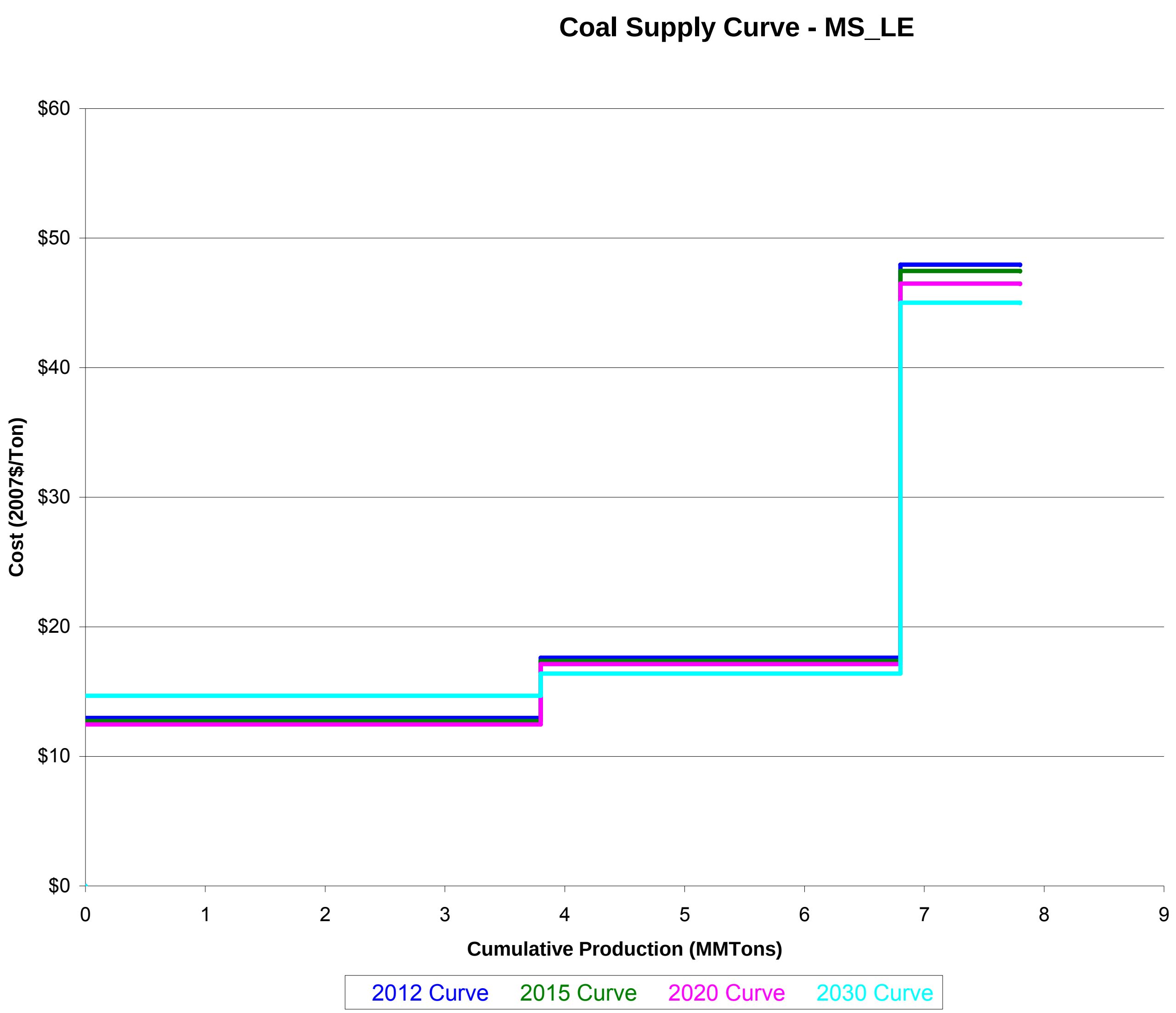



Coal Supply Curve - IN_BD
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

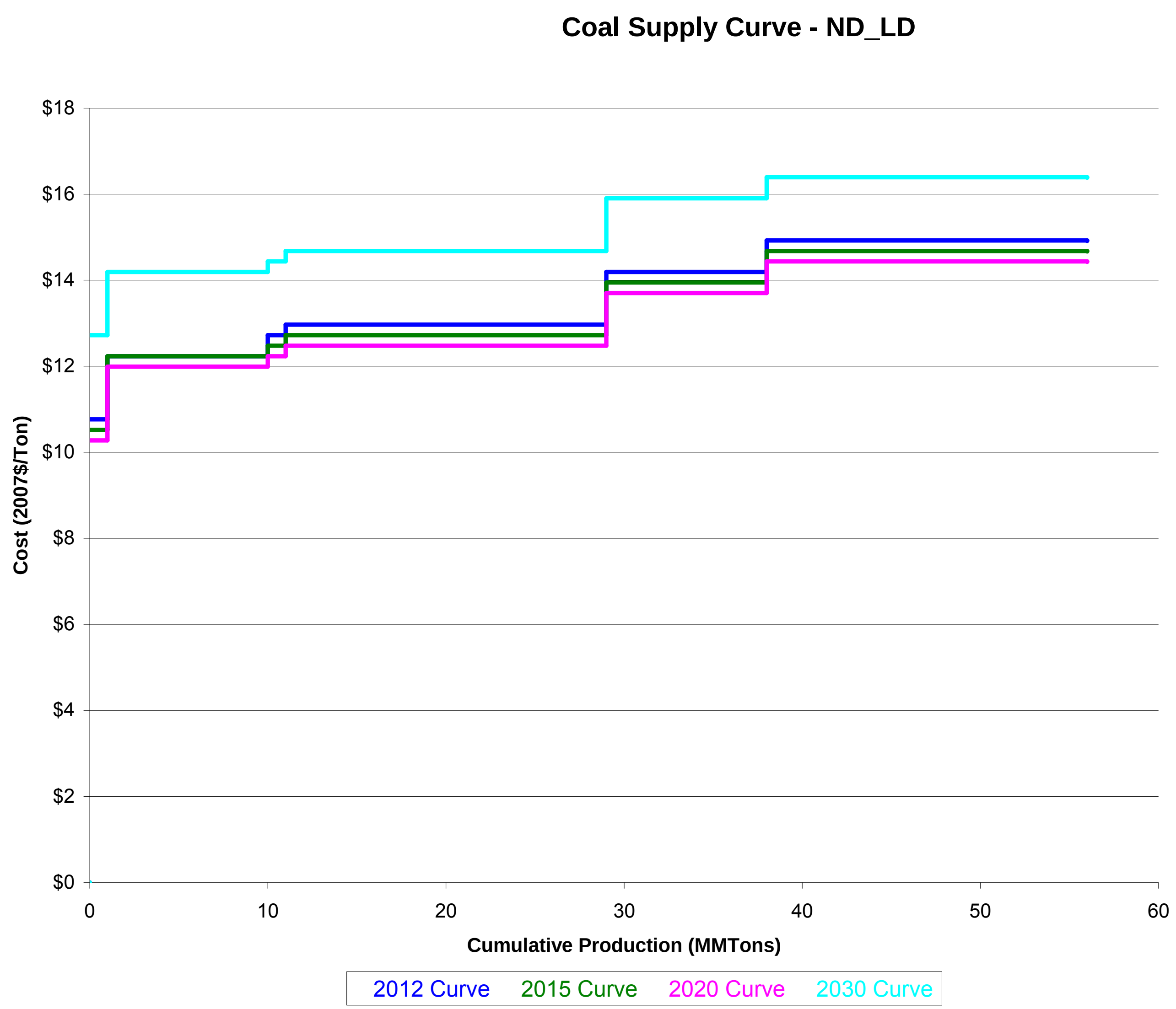

Coal Supply Curve - IN_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

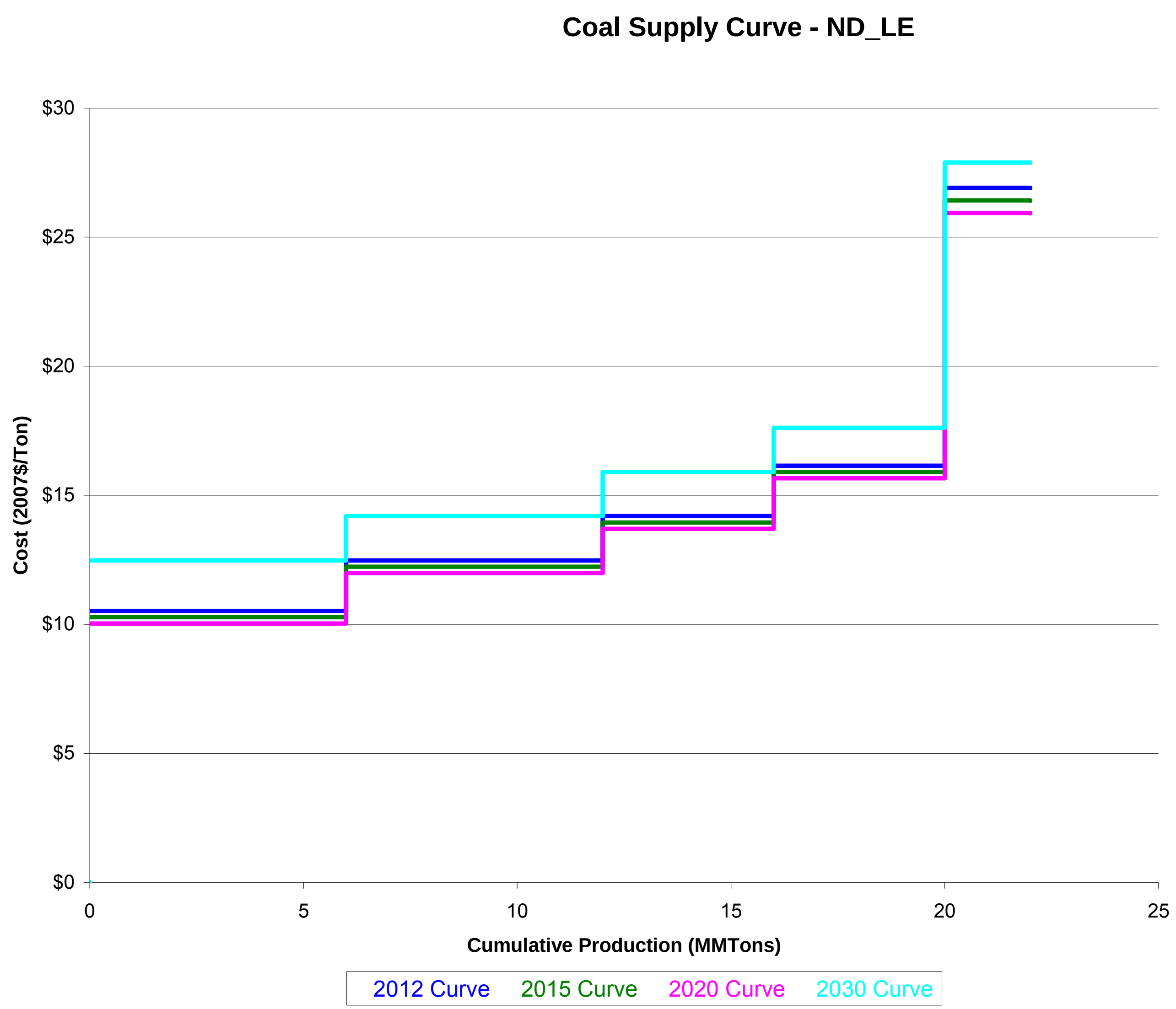

Coal Supply Curve - IN_BG
Cost (2007$/Ton)
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

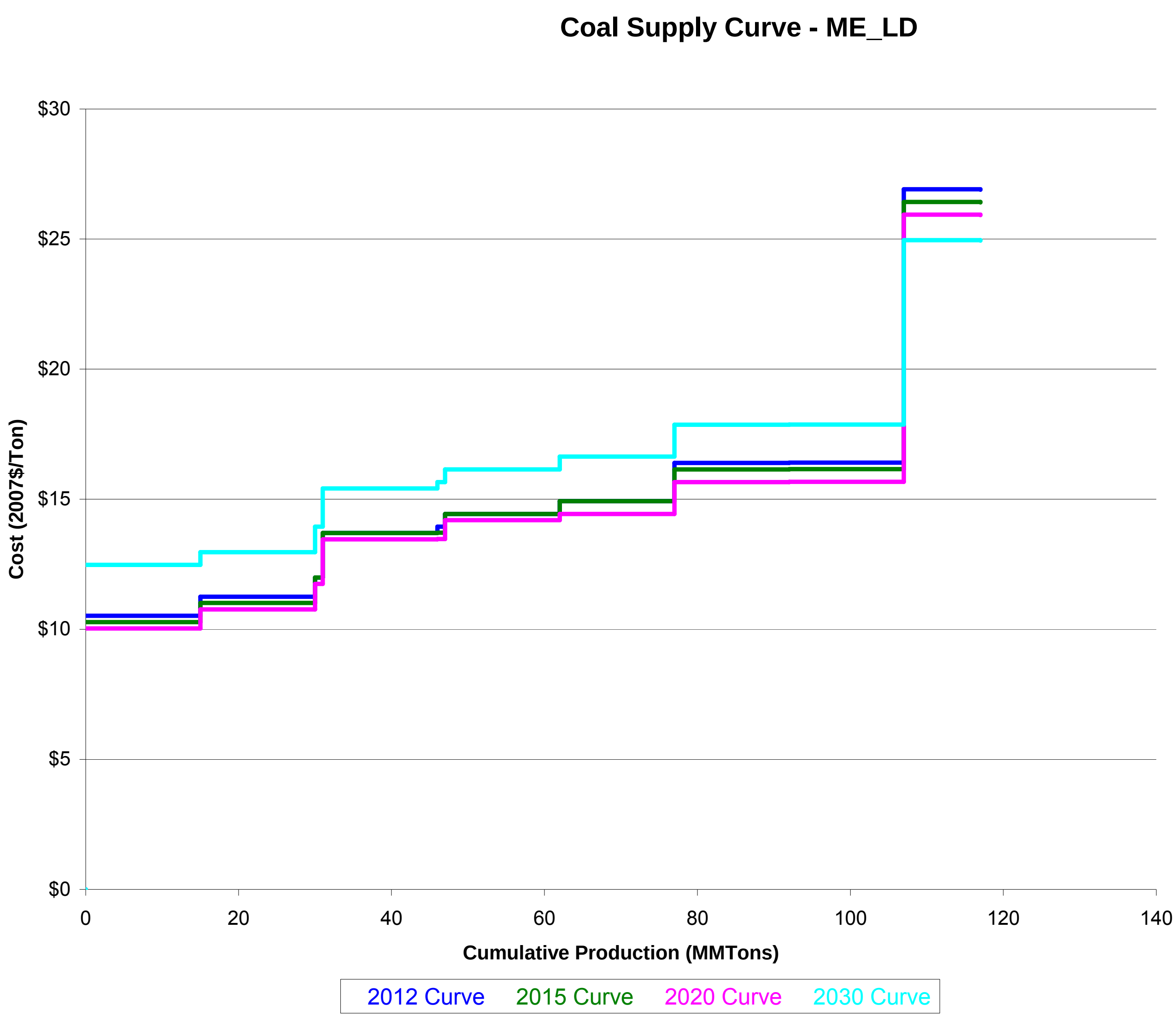

Coal Supply Curve - IN_BH
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
70
80
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve



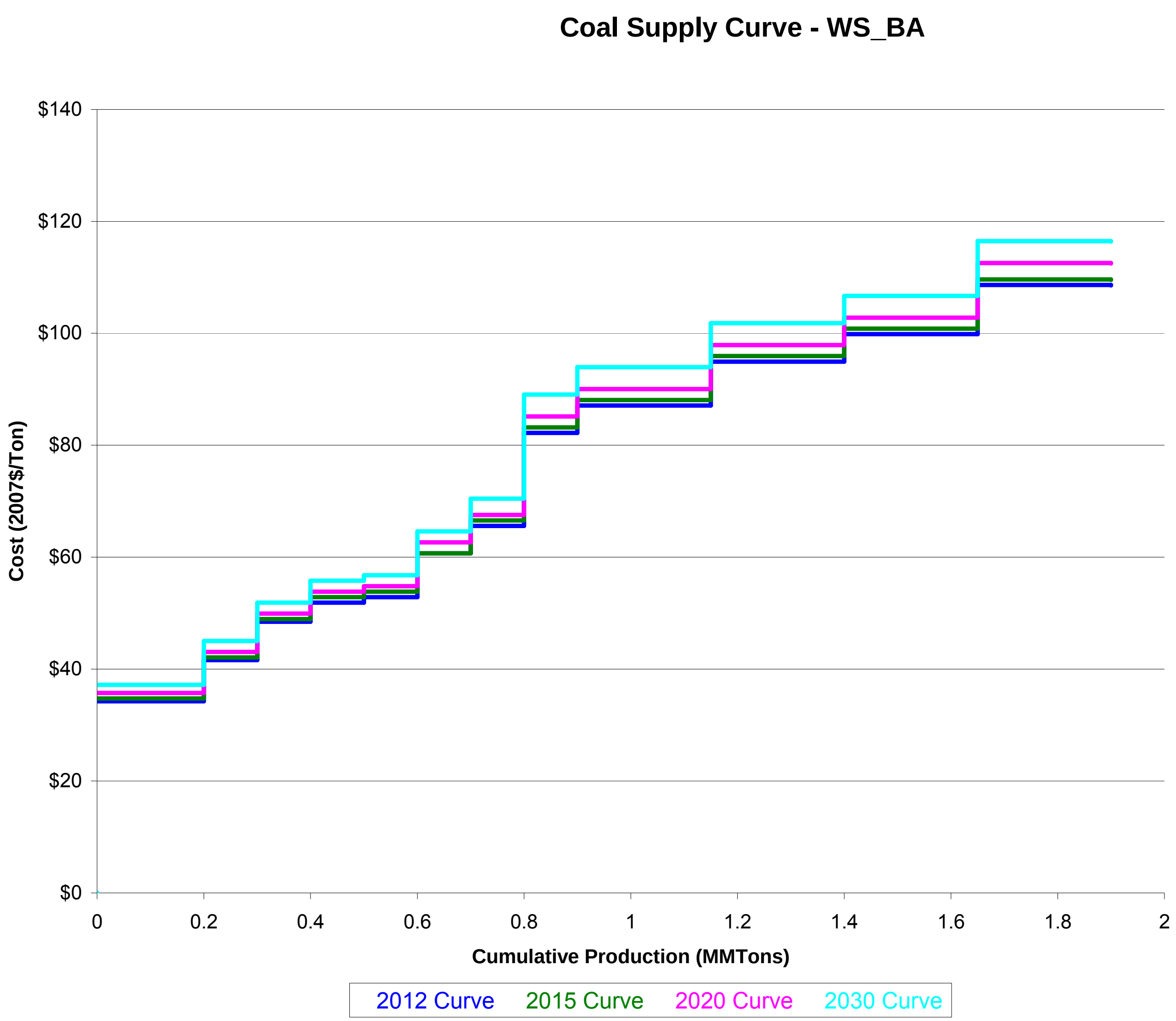
Coal Supply Curve - MS_LE
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

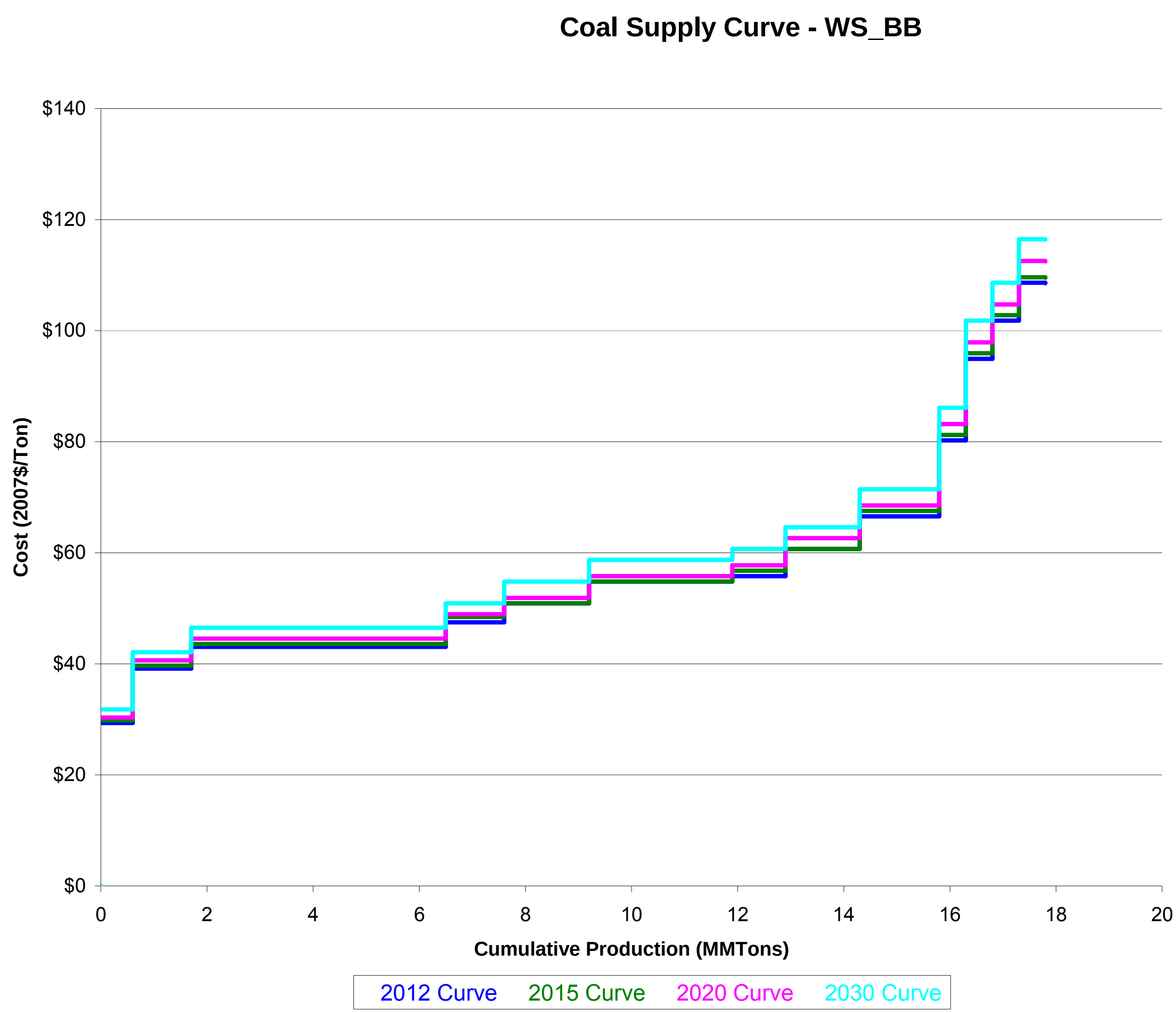

Coal Supply Curve - ND_LD
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

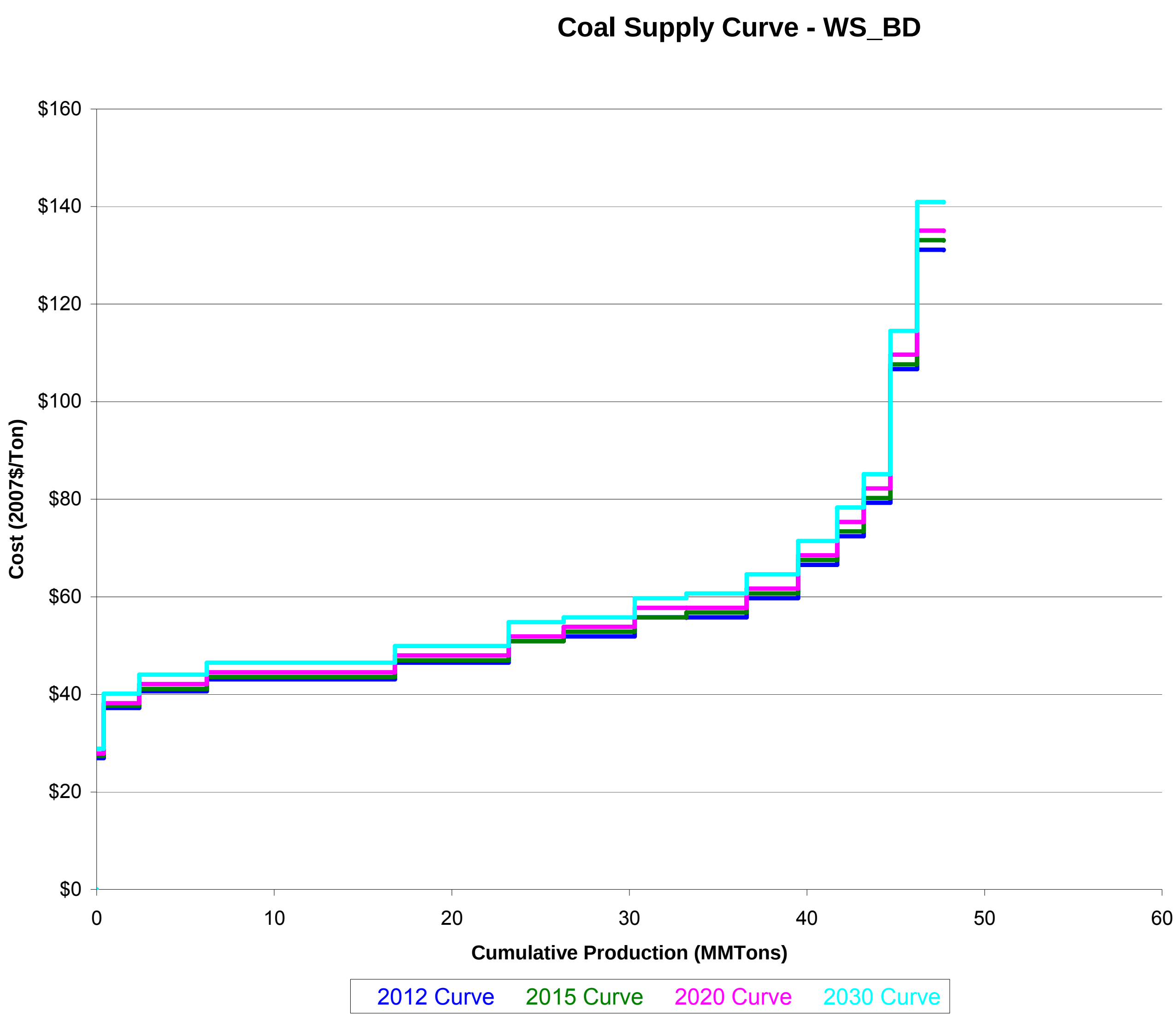

Coal Supply Curve - ND_LE
Cost (2007$/Ton)
$30
$25
$20
$15
$10
$5
$0
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve



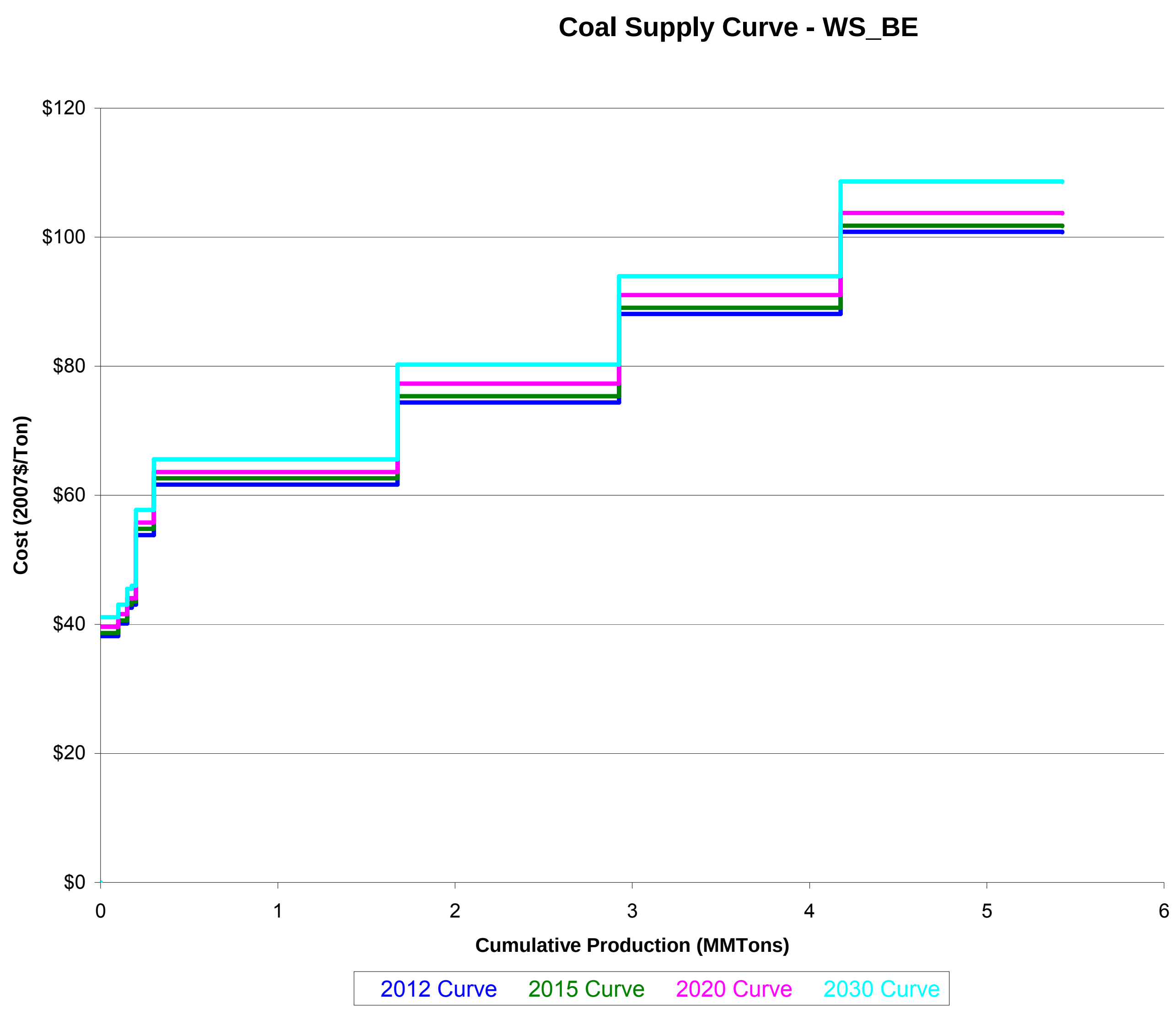
Coal Supply Curve - ME_LD
Cost (2007$/Ton)
$30
$25
$20
$15
$10
$5
$0
0
20
40
60
80
100
120
140
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

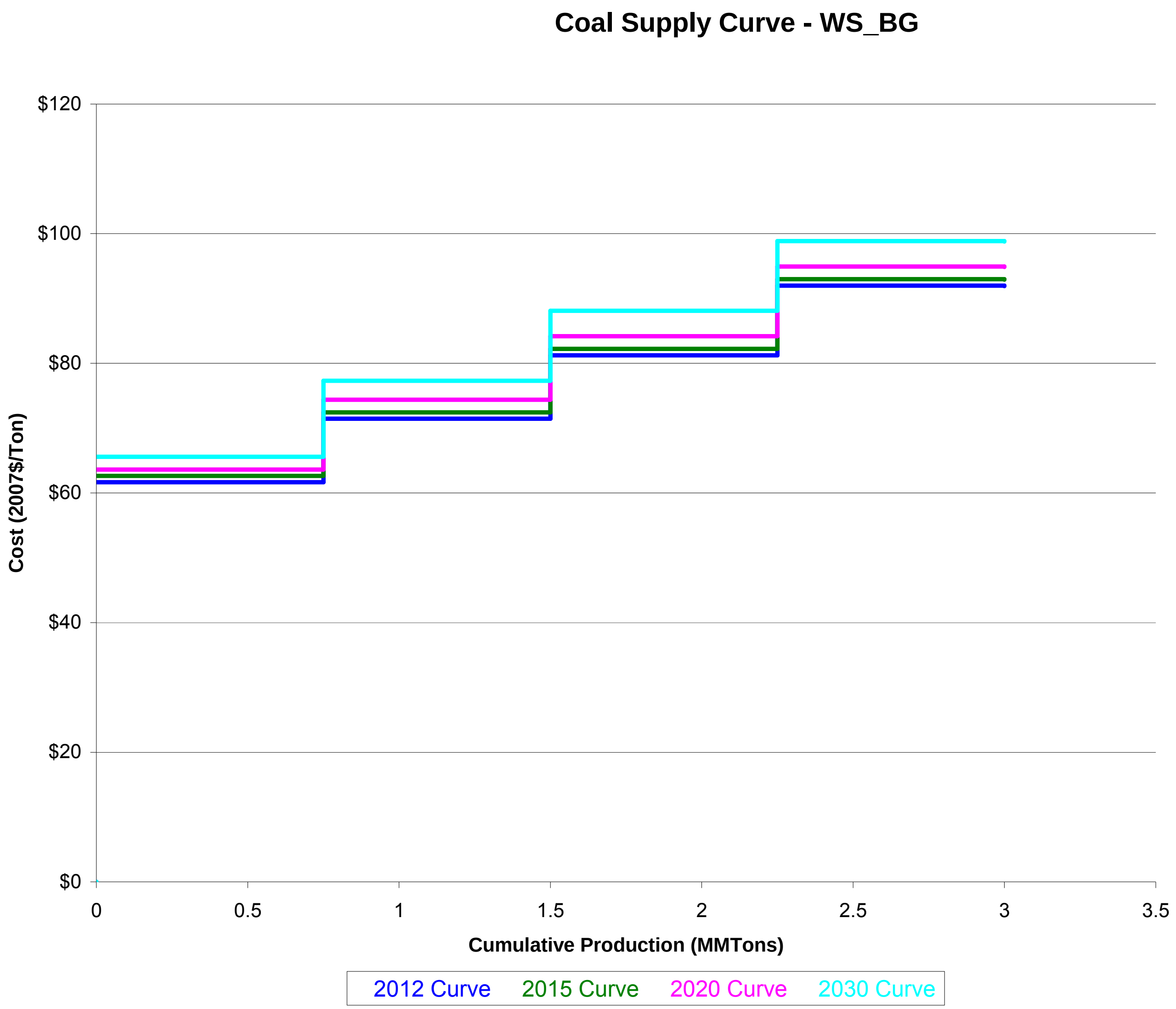

Coal Supply Curve - WS_BA
Cost (2007$/Ton)
$140
$120
$100
$80
$60
$40
$20
$0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
2
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

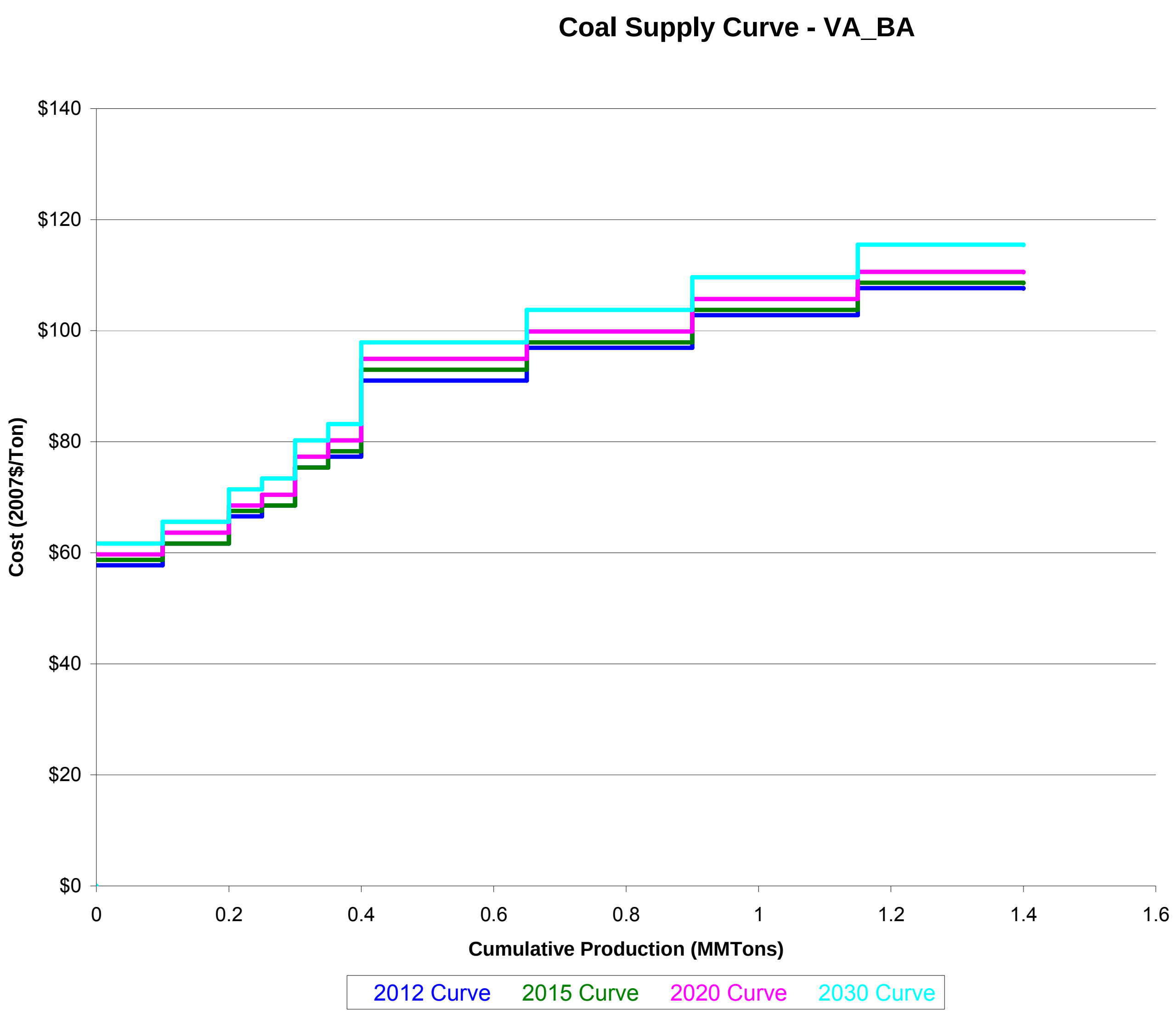

Coal Supply Curve - WS_BB
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
20
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve



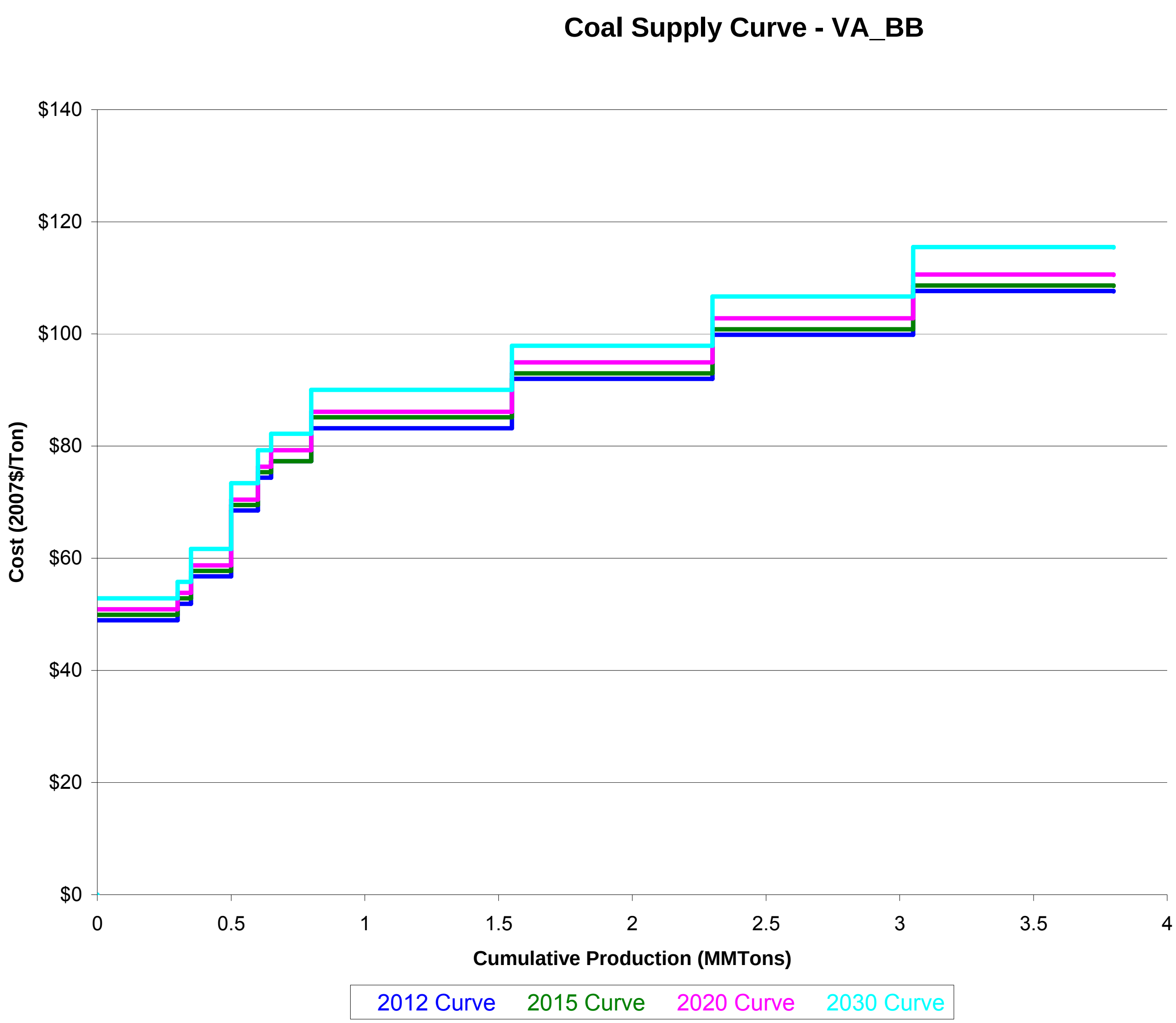
Coal Supply Curve - WS_BD
Cost (2007$/Ton)
$160
$140
$120
$100
$80
$60
$40
$20
$0
0
10
20
30
40
50
60
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

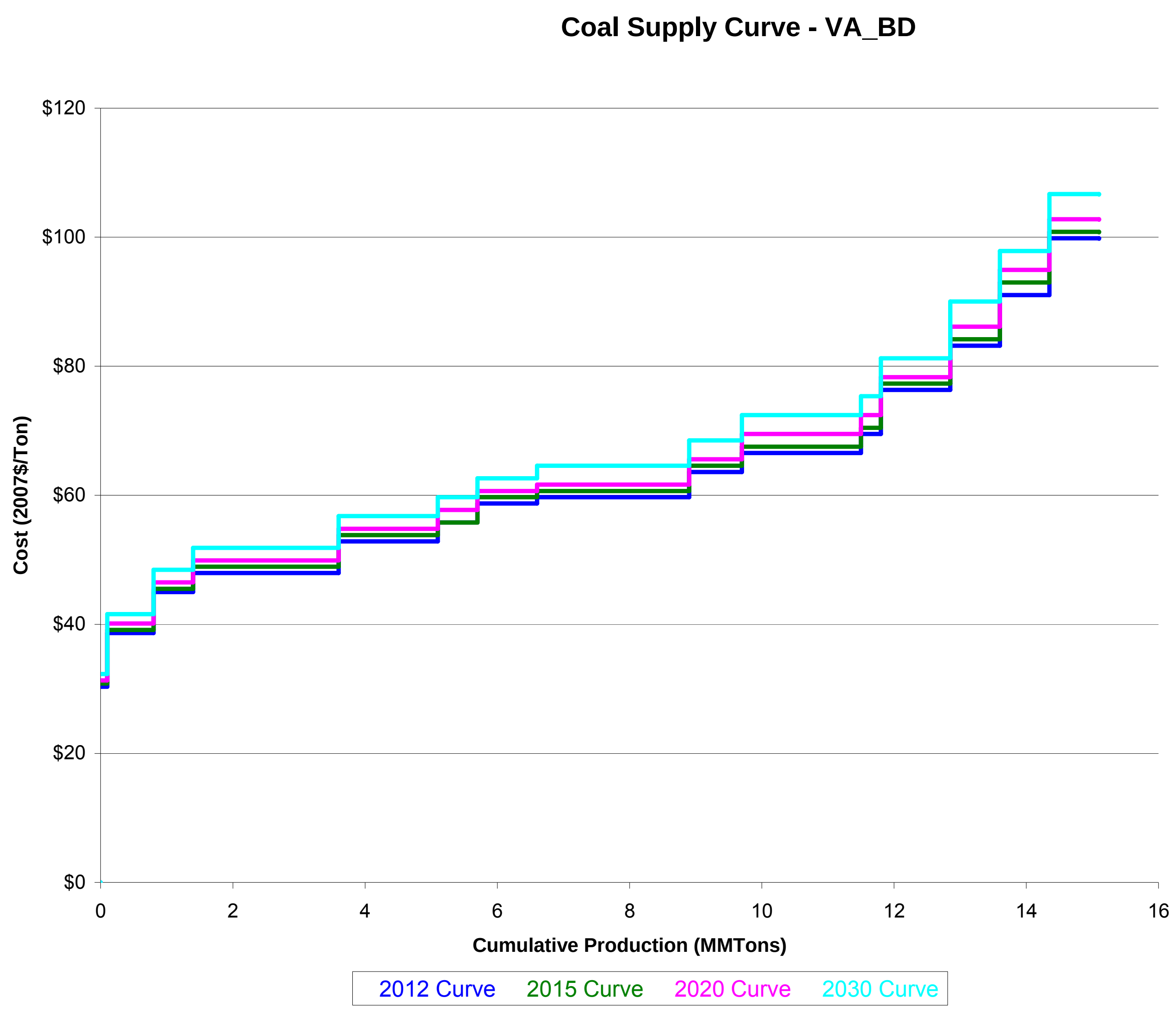

Coal Supply Curve - WS_BE
$120
$100
$80
$60
$40
$20
$0
0
1
2
3
4
5
6
Cost (2007$/Ton)
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - WS_BG
Cost (2007$/Ton)
$120
$100
$80
$60
$40
$20
$0
0
0.5
1
1.5
2
2.5
3
3.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

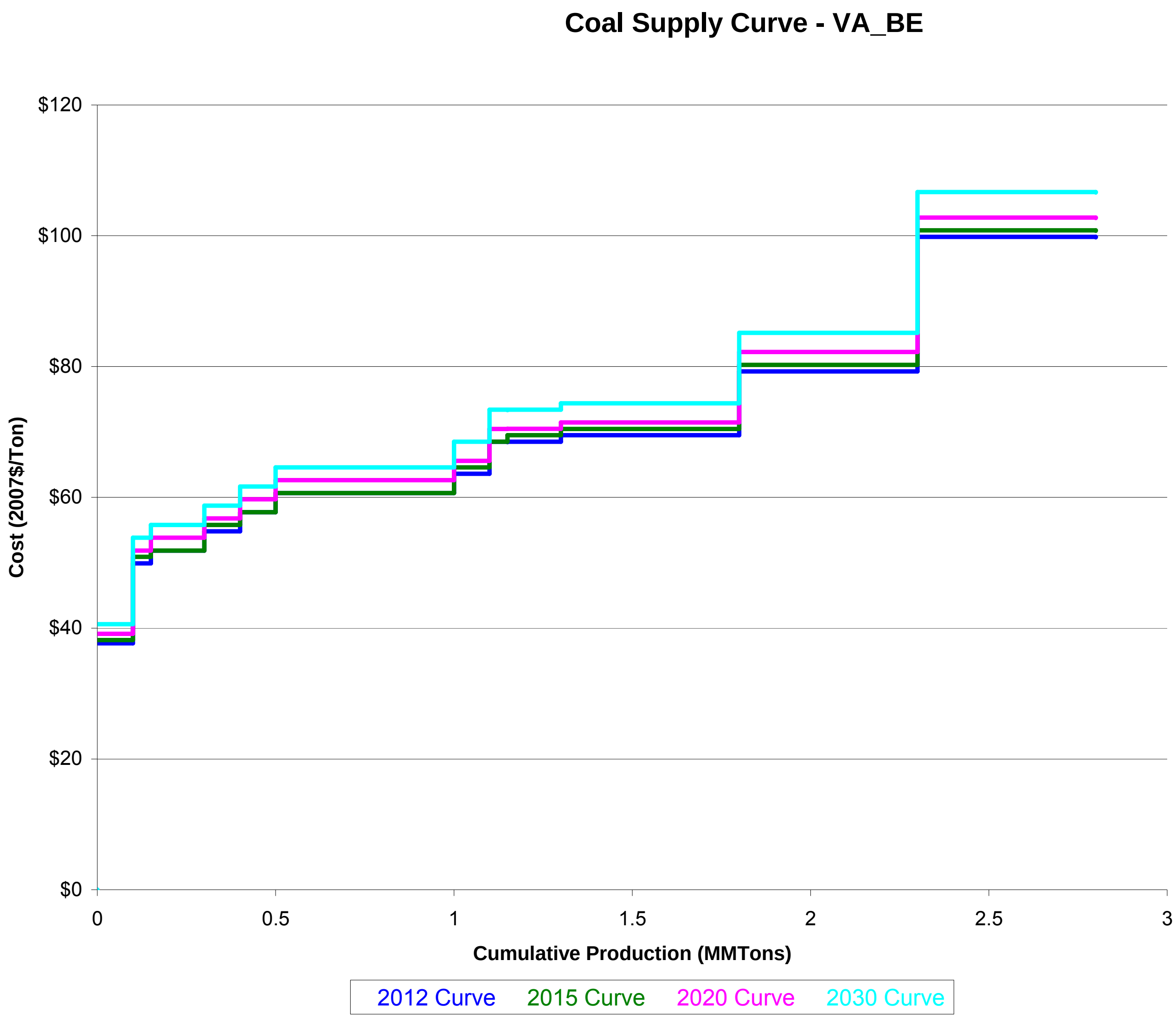


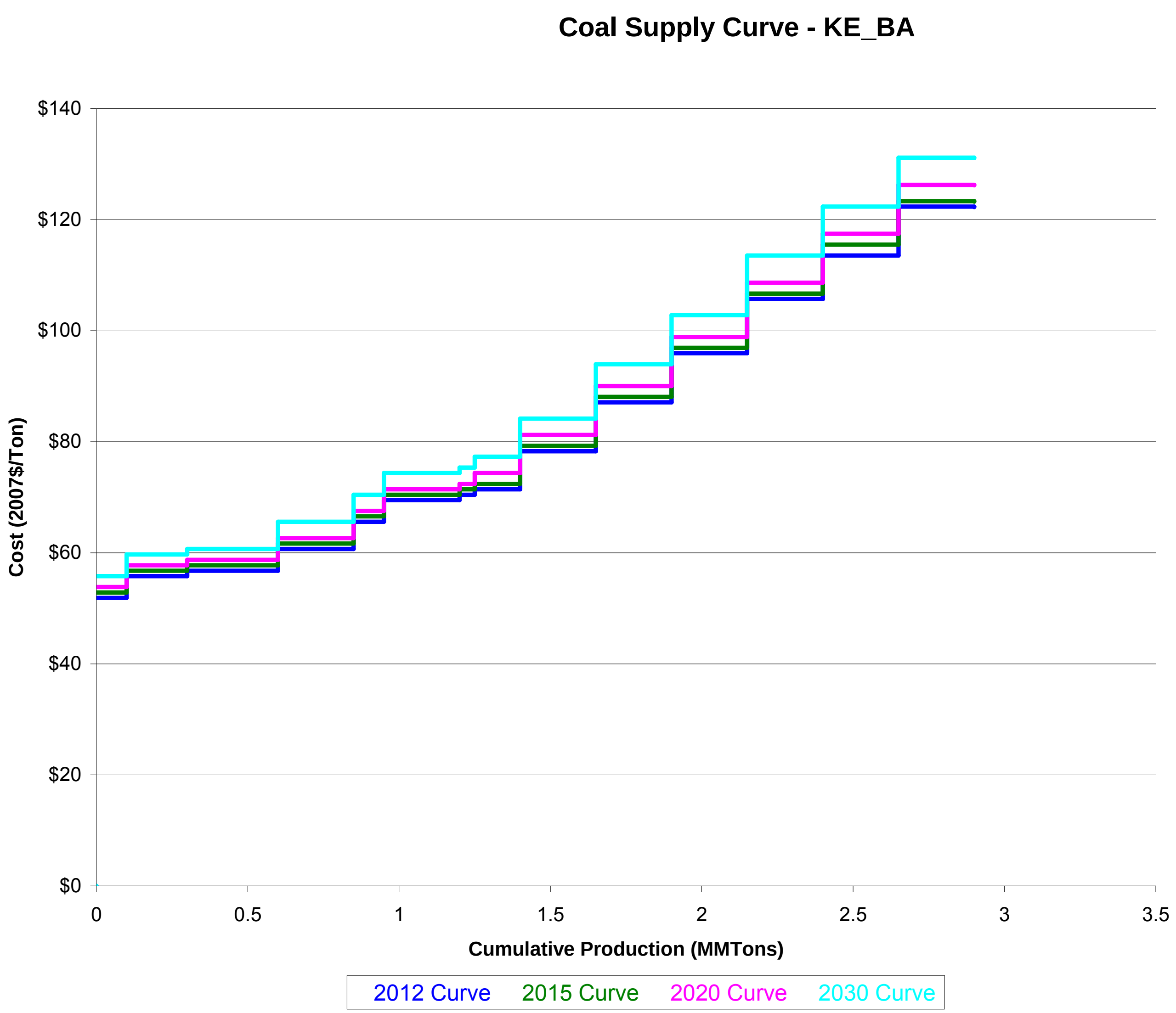
Coal Supply Curve - VA_BA
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - VA_BB
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

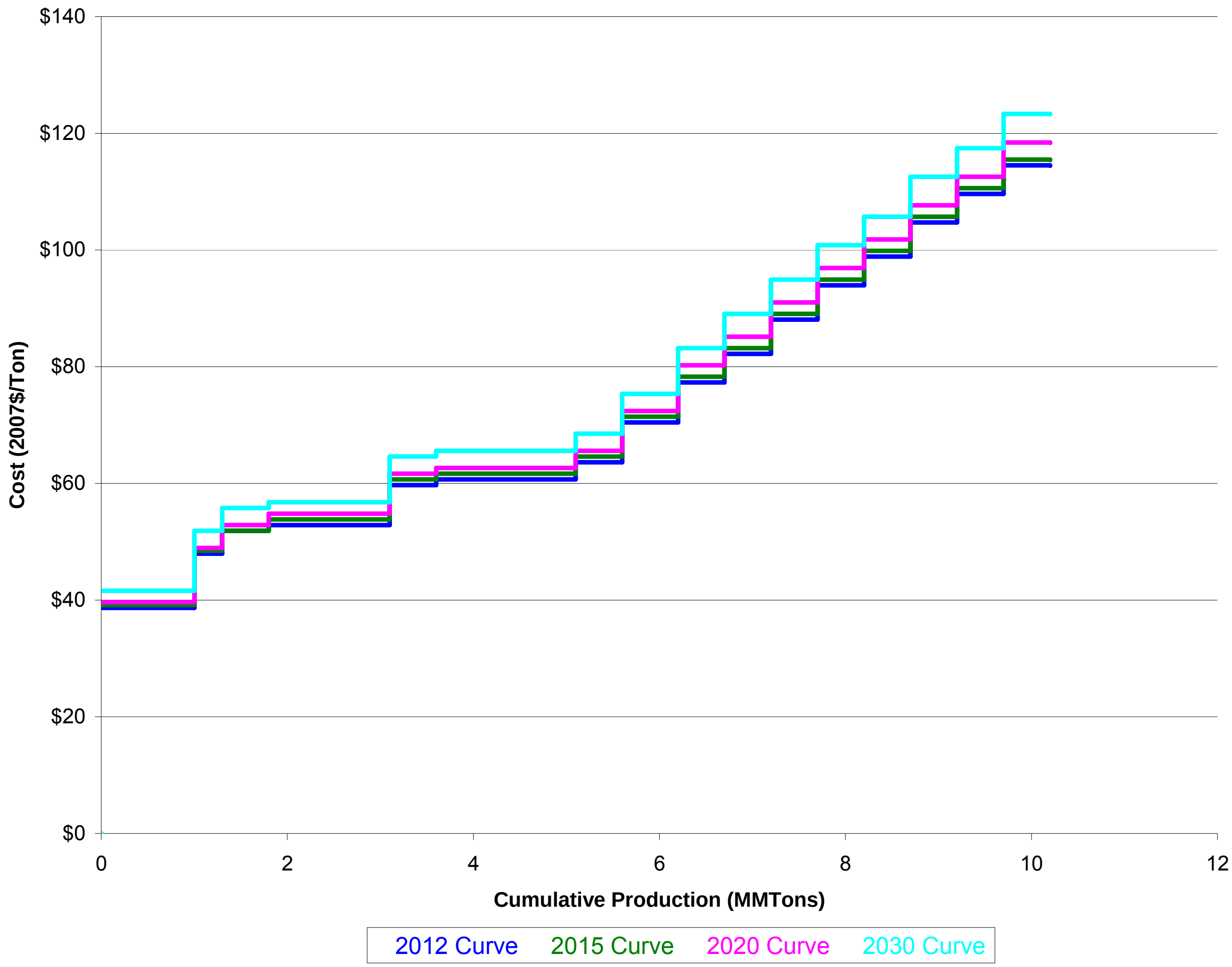


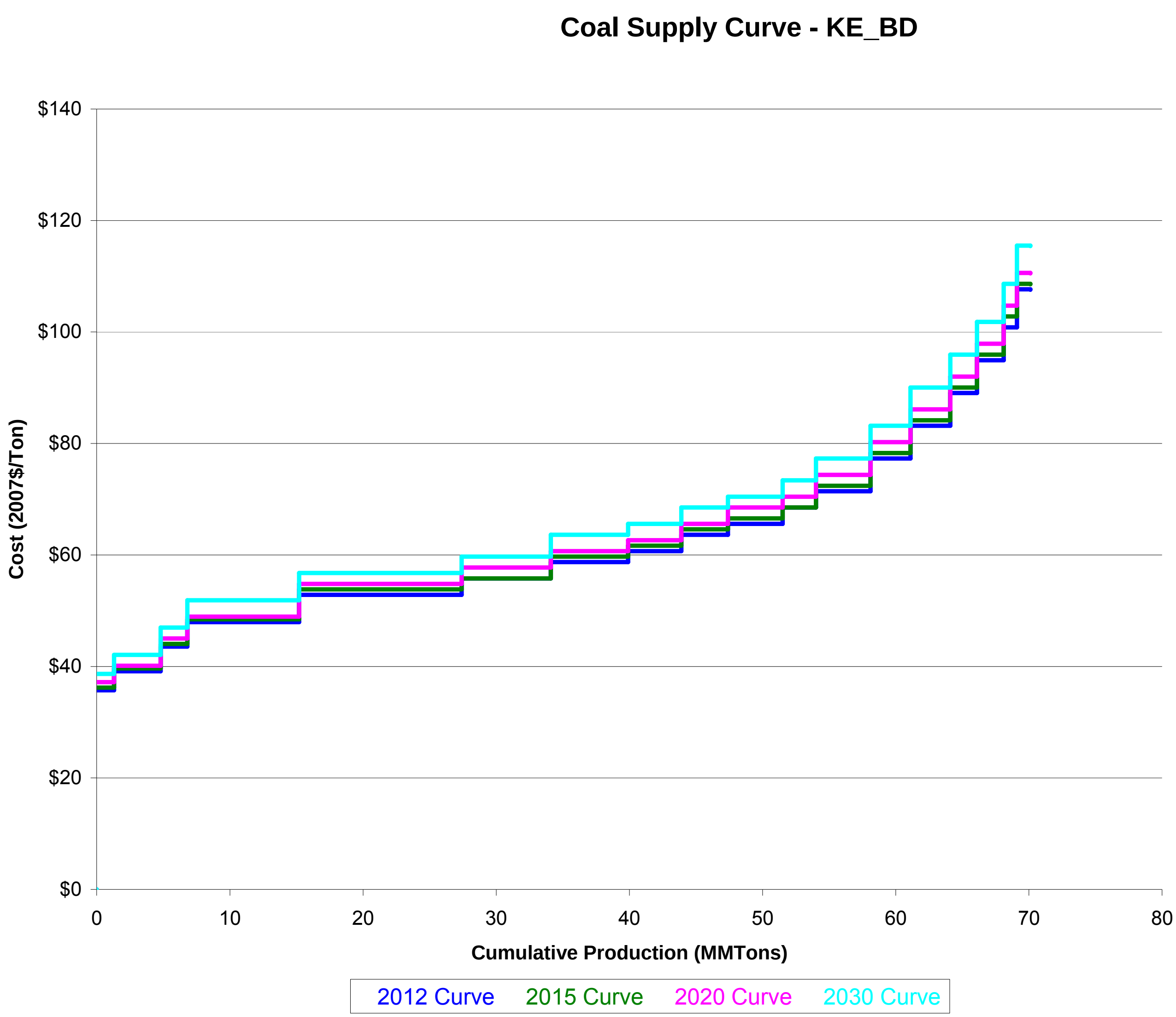
Coal Supply Curve - VA_BD
$120
$100
$80
$60
$40
$20
$0
0
2
4
6
8
10
12
14
16
Cost (2007$/Ton)
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - VA_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

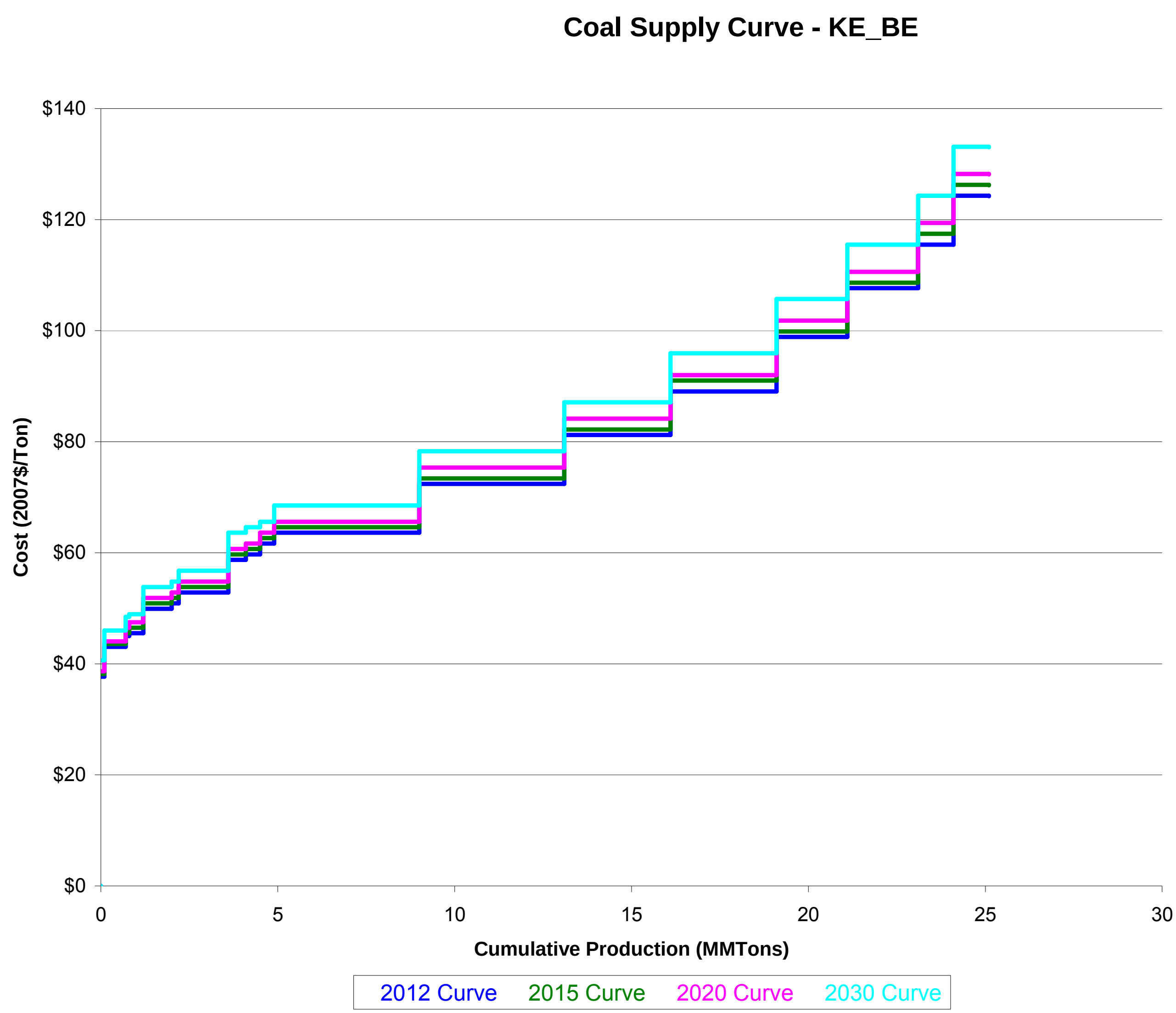

Coal Supply Curve - KE_BA
Cost (2007$/Ton)
$140
$120
$100
$80
$60
$40
$20
$0
0
0.5
1
1.5
2
2.5
3
3.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

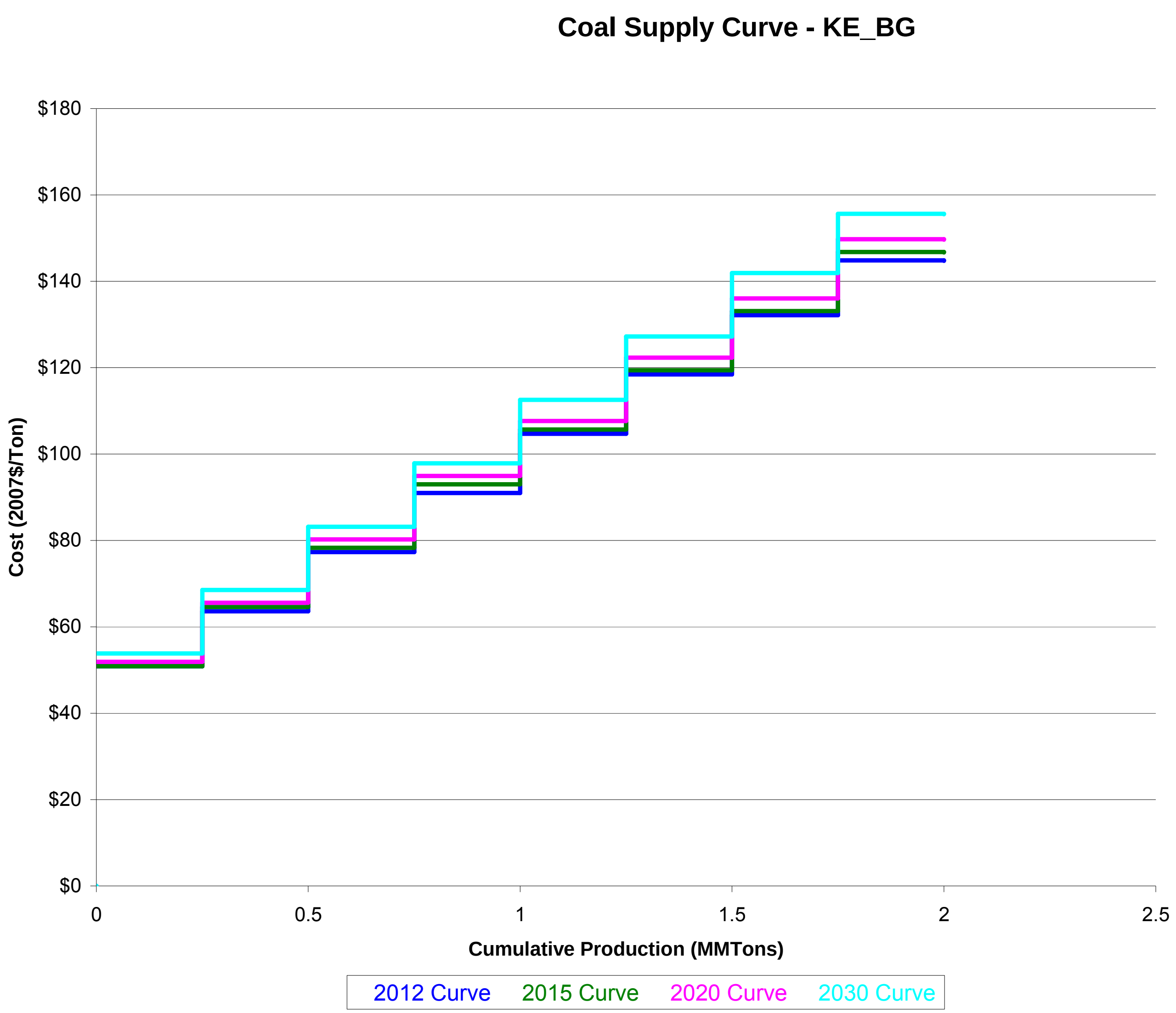
Coal Supply Curve - KE_BB

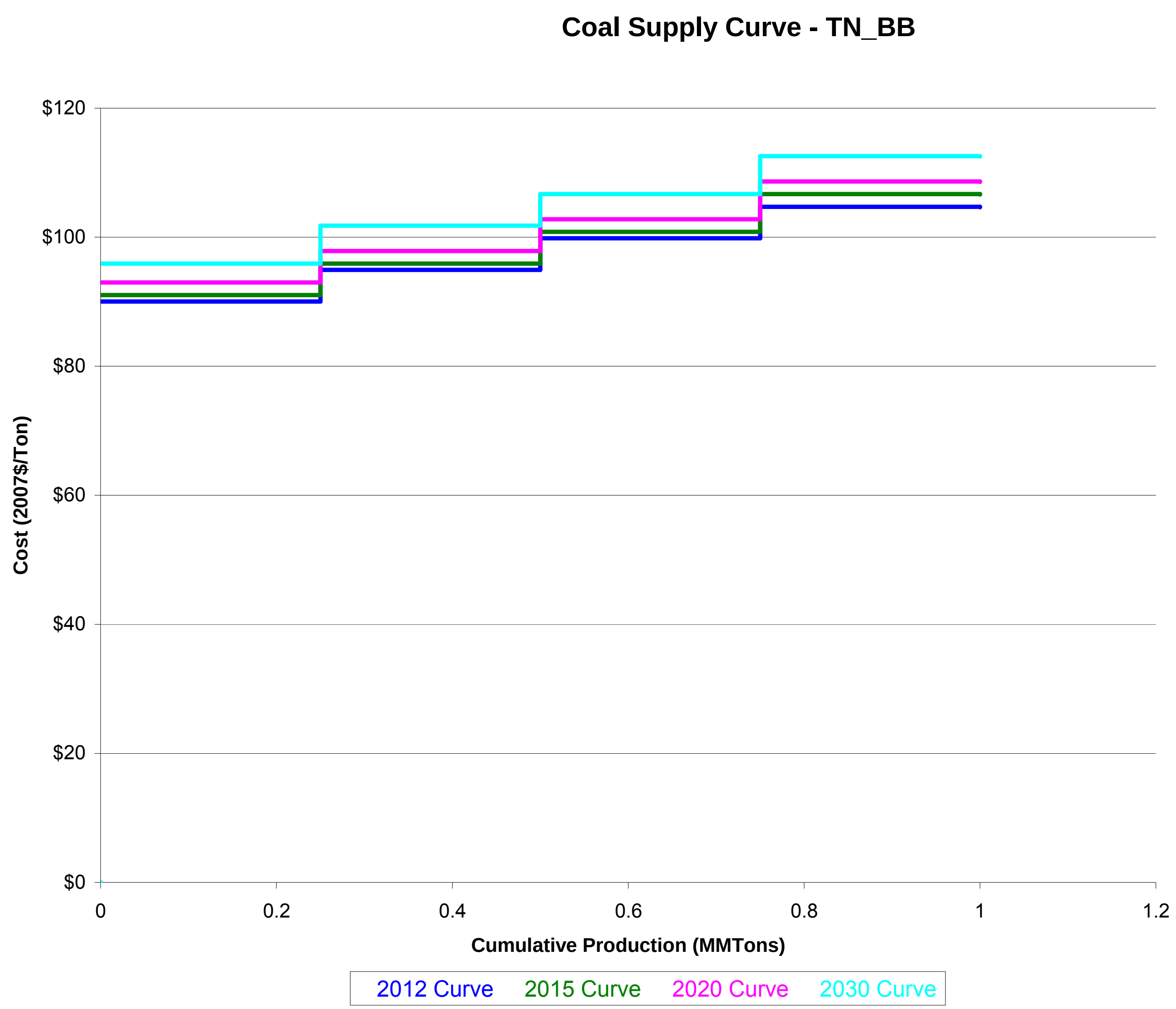


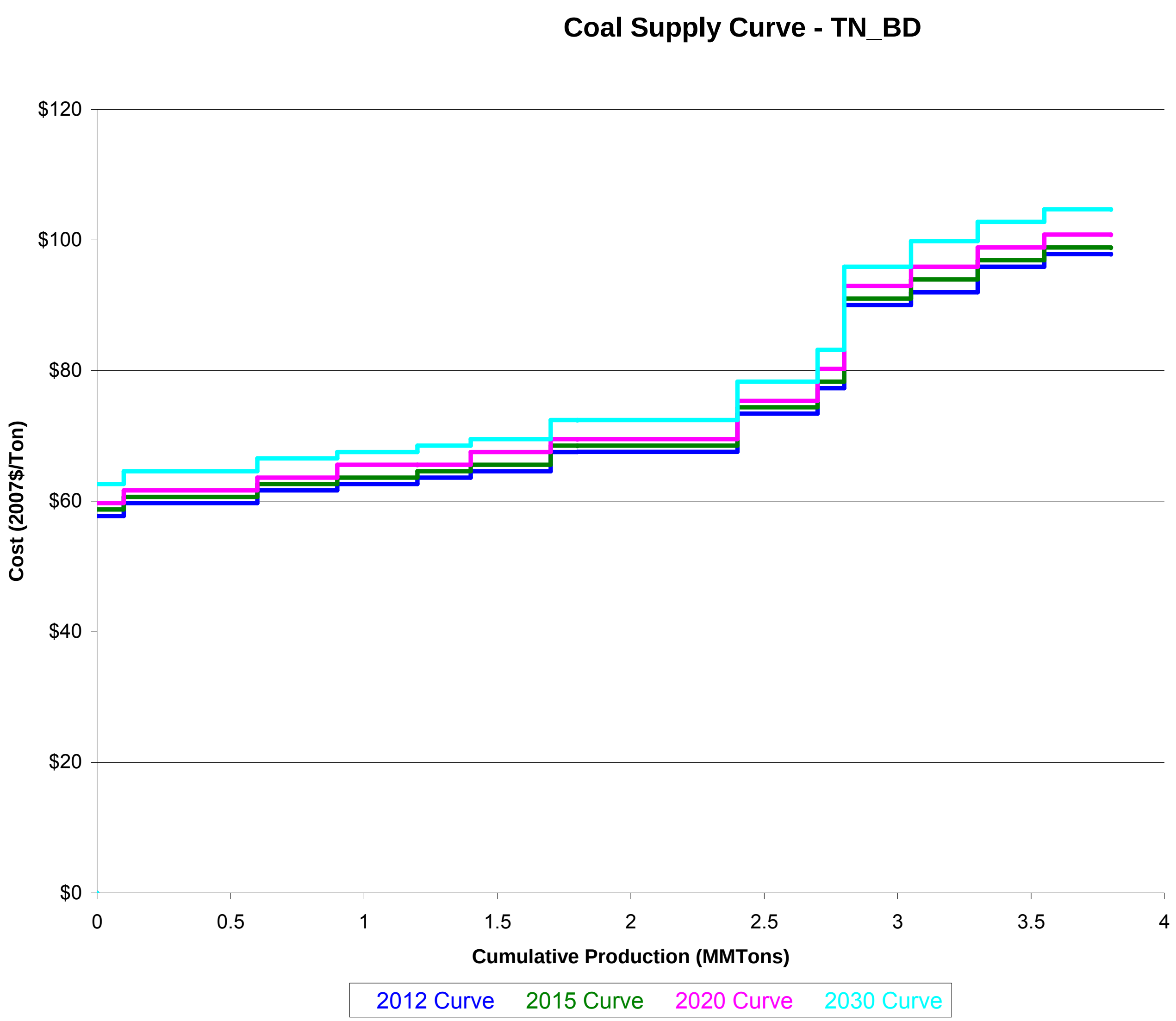


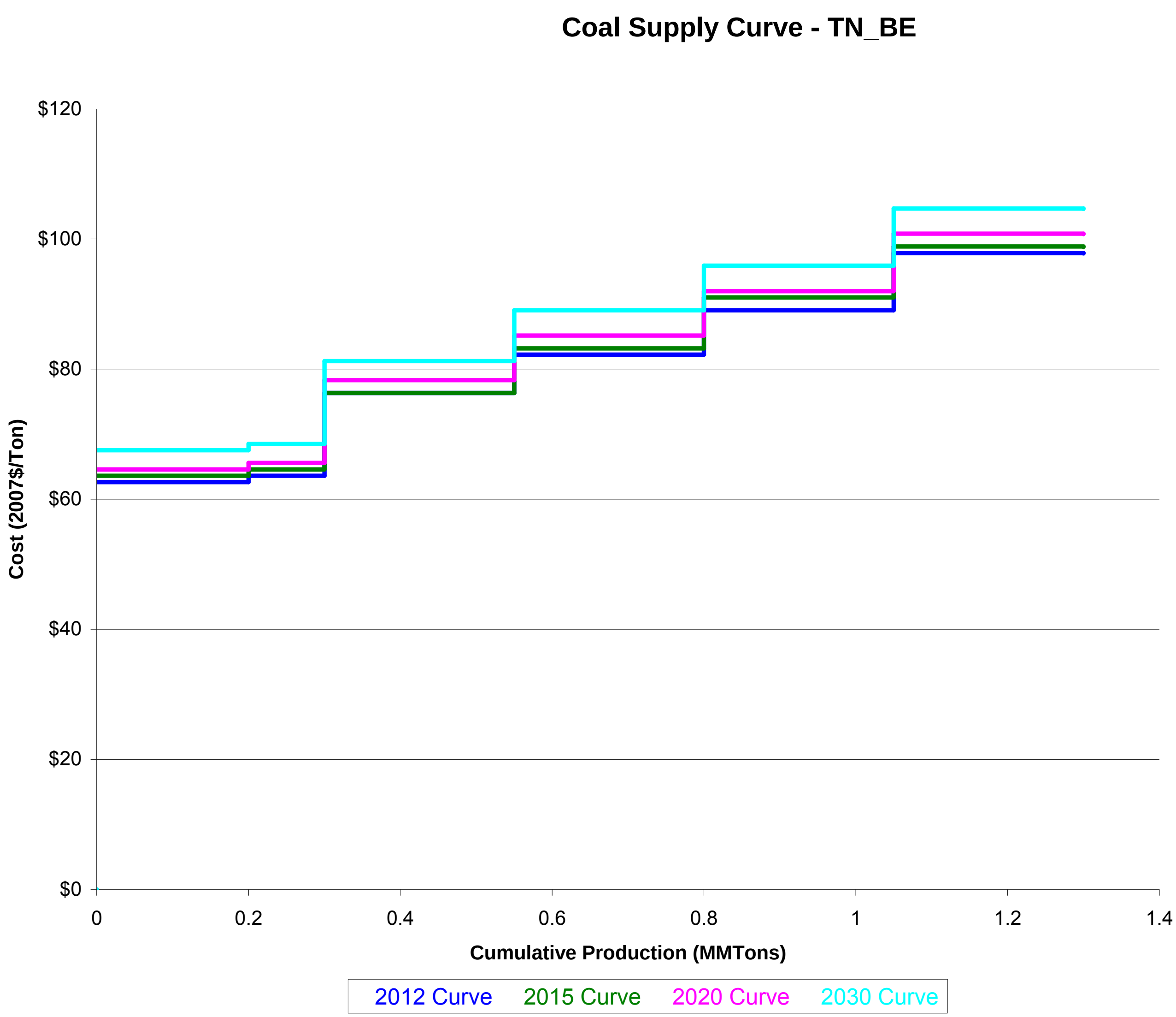
Coal Supply Curve - KE_BD
Cost (2007$/Ton)
$140
$120
$100
$80
$60
$40
$20
$0
0
10
20
30
40
50
60
70
80
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

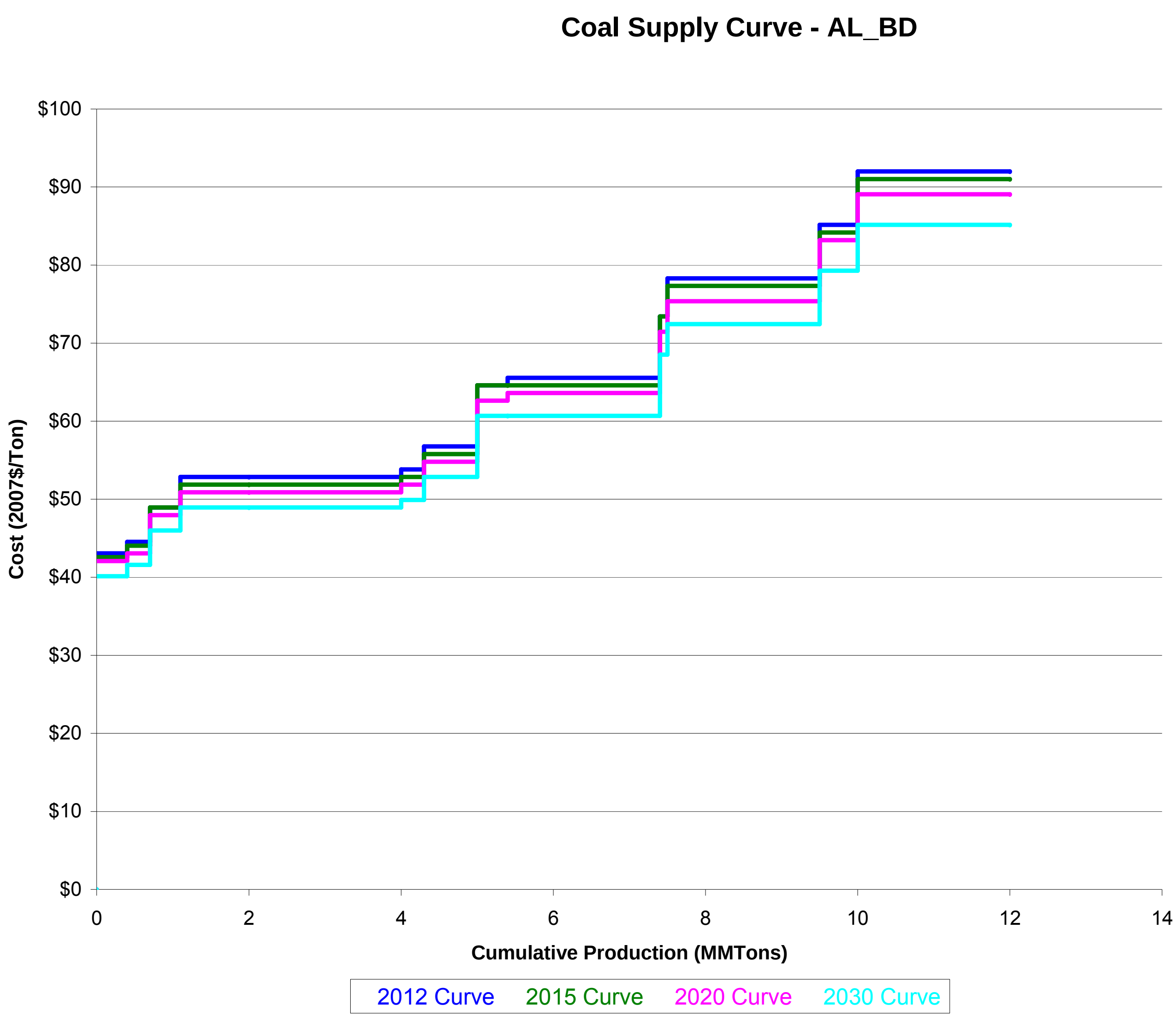

Coal Supply Curve - KE_BE
Cost (2007$/Ton)
$140
$120
$100
$80
$60
$40
$20
$0
0
5
10
15
20
25
30
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - KE_BG
Cost (2007$/Ton)
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
0
0.5
1
1.5
2
2.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

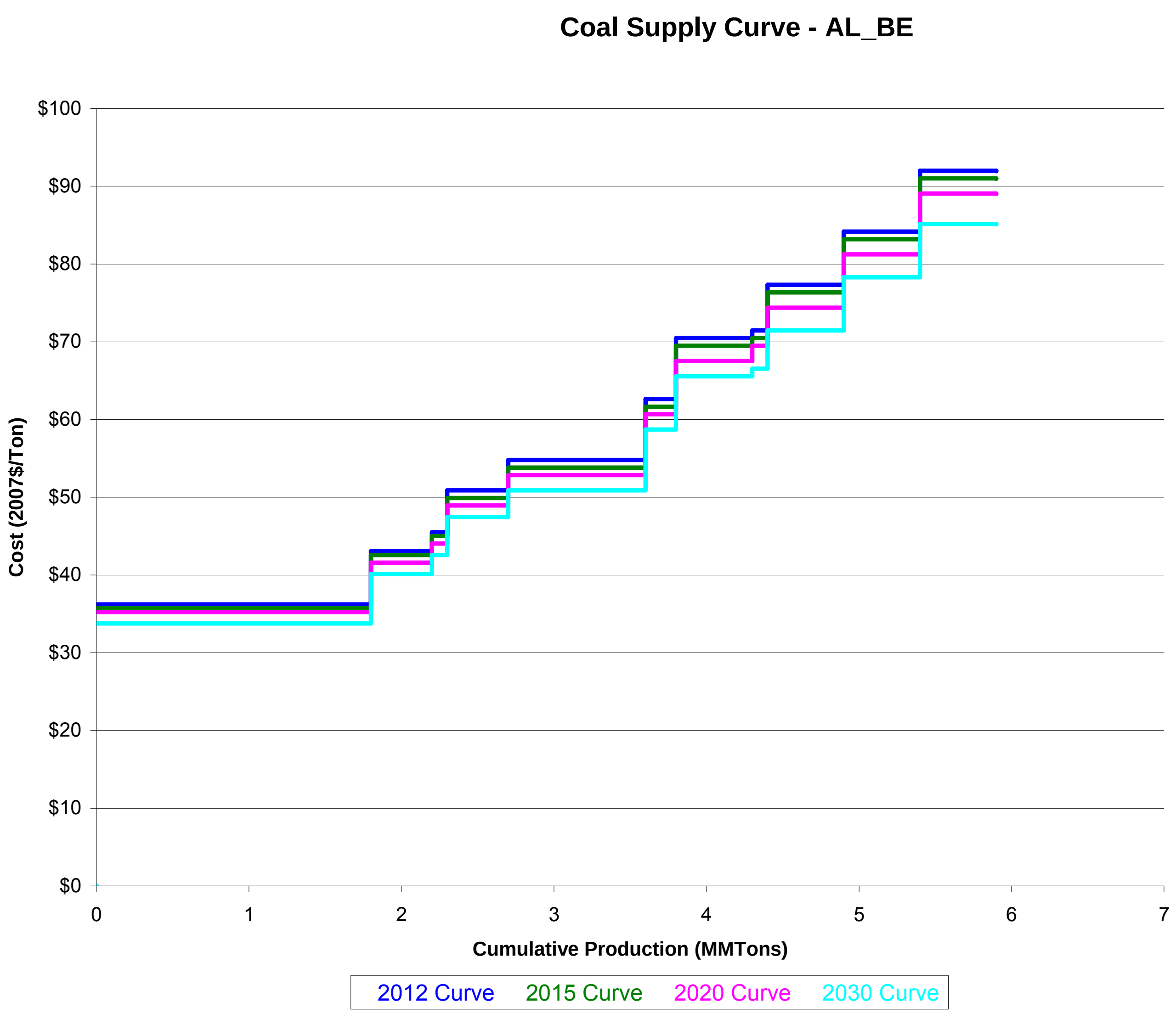

Coal Supply Curve - TN_BB
Cost (2007$/Ton)
$120
$100
$80
$60
$40
$20
$0
0
0.2
0.4
0.6
0.8
1
1.2
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

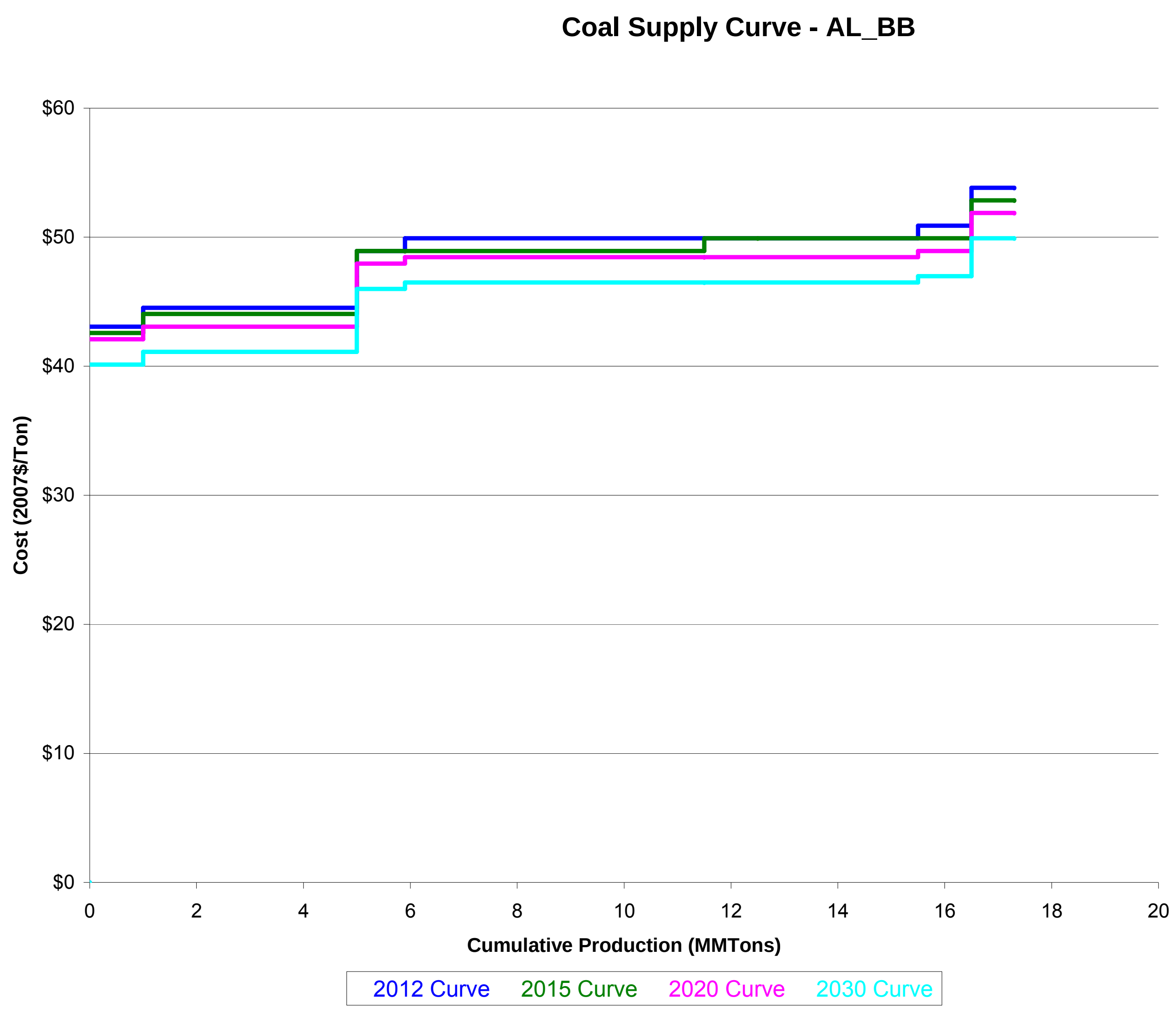

Coal Supply Curve - TN_BD
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - TN_BE
Cost (2007$/Ton)
$0
$20
$40
$60
$80
$100
$120
0
0.2
0.4
0.6
0.8
1
1.2
1.4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve



Coal Supply Curve - AL_BD
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - AL_BE
Cost (2007$/Ton)
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
0
1
2
3
4
5
6
7
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - AL_BB
Cost (2007$/Ton)
$0
$10
$20
$30
$40
$50
$60
0
2
4
6
8
10
12
14
16
18
20
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve