9. Coal

The next three chapters cover the representation and underlying assumptions for fuels in EPA Base Case v.5.13. 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.5.13. 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.5.13 and the 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 67 coal supply curves that are implemented in EPA Base Case v.5.13. Illustrative examples are included of the step-by-step approach employed in developing the 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 June 2013, 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): TetraTech (coal transportation and team coordination), Wood Mackenzie (coal supply curve development), Hellerworx (coal transportation and third party review), and ICF (representation in IPM). The coal supply curves and transportation matrix implemented in EPA Base Case v.5.13 are included in tables and attachments at the end of this chapter.

9.1 Coal Market Representation in EPA Base Case v.5.13

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.5.13. 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-fired power plant modeled is reflected as its own coal demand region. The demand regions are defined to reflect the coal transportation options (rail, barge, truck, conveyer belt) that are available to the plant. These demand regions are interconnected by a transportation network to at least one of the 36 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.5.13 the endogenous demand for coal is generated by coal fired power plants interacting with a set of exogenous supply curves (see Table 9-24 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 the 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

Excerpt from Table 9-23 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 the entire electric system is 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

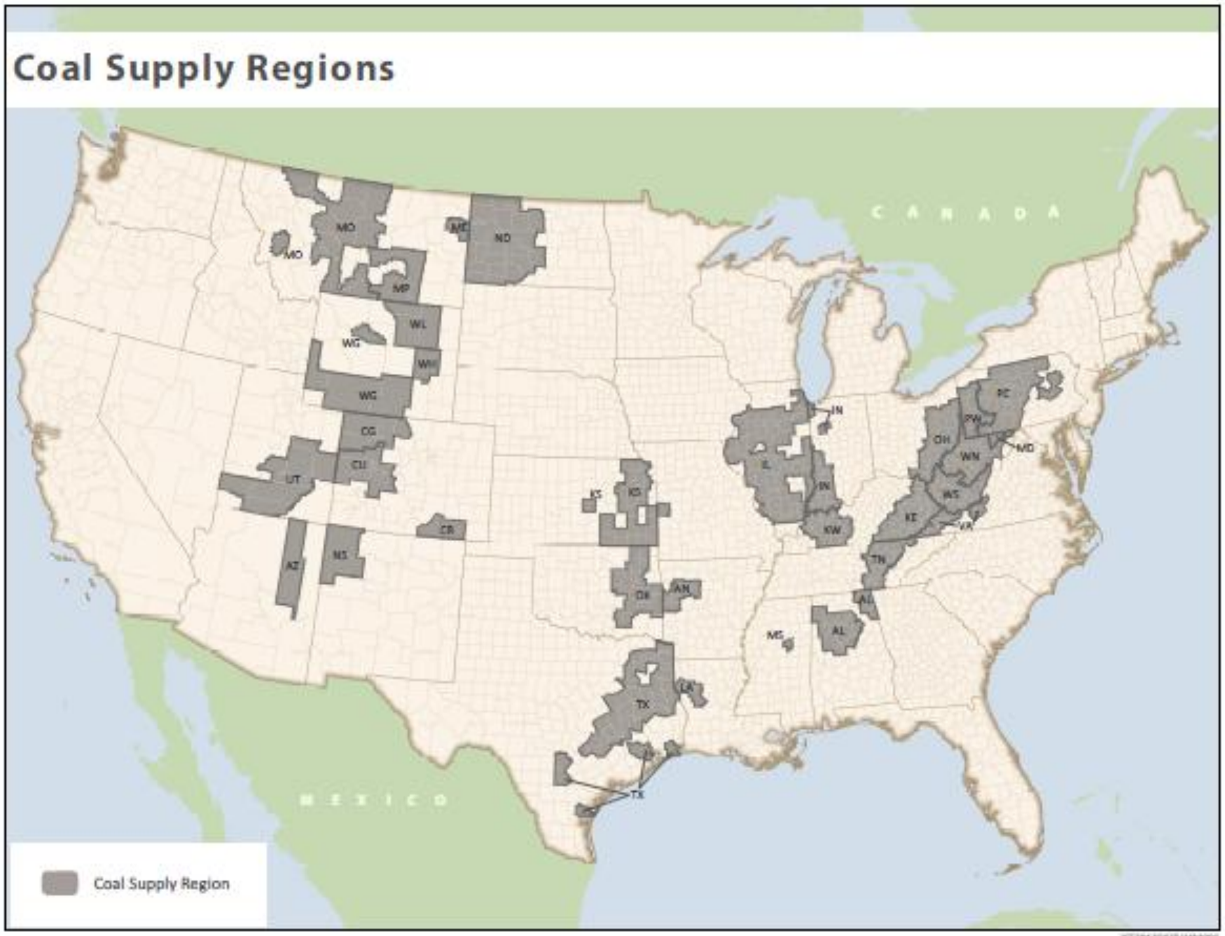
There are 36 coal supply regions in EPA Base Case v.5.13, each representing geographic aggregations of coal-mining areas that supply one or more coal grades. Coal supply regions may differ from one another in the types and quality of coal they can supply. Table 9-1 lists the coal supply regions included in EPA Base Case v.5.13.

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
Gulf Lignite	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	Arkansas, North	AN
West Interior	Kansas	KS
West Interior	Missouri	MO
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
Alberta	Alberta, Canada	AB
British Columbia	British Columbia, Canada	BC
Saskatchewan	Saskatchewan, Canada	SK

Figure 9-1 Map of the Coal Supply Regions in EPA Base Case v.5.13



9.1.2 Coal Demand Regions

Coal demand regions are designed to reflect coal transportation options available to power plants. Each existing coal plant is reflected as its own individual demand region. The transportation infrastructure (i.e., rail, barge, or truck/conveyor belt), proximity to mine (i.e., mine mouth or not mine mouth), and transportation competitiveness levels (i.e., non-competitive, low-cost competitive, or high-cost competitive) are developed specific to each coal plant (demand region).

When IPM is run, it determines the amount and type of new generation capacity to add within each of IPM's 64 US model regions. These model regions reflect the administrative, operational, and transmission geographic structure of the electricity grid. Since these new plants could be located at various locations within the region, a generic transportation cost for different coal types is developed for these new plants and the methodology for deriving that cost is described in the transportation section of this chapter. See Table 9-2 for the list of coal plant demand regions reflected in the transportation matrix.

Table 9-2 Coal Demand Regions in EPA Base Case

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
1004	Edwardsport	C181	
1010	Wabash River	C183	
10684	Argus Cogen Plant	C563	
1077	Sutherland	C194	
1554	Herbert A Wagner	C227	
1606	Mount Tom	C232	
1943	Hoot Lake	C259	
2682	S A Carlson	C303	
2943	Shelby Municipal Light Plant	C339	
3319	Jefferies	C365	
511	Trinidad	C131	
54407	Waupun Correctional Central Heating Plt	C624	
55856	Prairie State Generatng Station	C637	MIS_IL
56564	John W Turk Jr Power Plant	C644	SPP_WEST
56785	Virginia Tech Power Plant	C651	
56808	Virginia City Hybrid Energy Center	C653	
7	Gadsden	C101	
7242	Polk	C495	
728	Yates	C151	
991	Eagle Valley	C176	
10	Greene County	C103	
10003	Colorado Energy Nations Company	C514	
1001	Cayuga	C180	
10043	Logan Generating Company LP	C517	
10071	Portsmouth Genco LLC	C518	
10075	Taconite Harbor Energy Center	C519	
1008	R Gallagher	C182	
10113	John B Rich Memorial Power Station	C520	
1012	F B Culley	C184	
10143	Colver Power Project	C521	
10148	White Pine Electric Power	C522	
10151	Grant Town Power Plant	C523	
1024	Crawfordsville	C185	
1032	Logansport	C186	
10328	T B Simon Power Plant	C528	
10333	Central Power & Lime	C529	
10343	Foster Wheeler Mt Carmel Cogen	C530	
1037	Peru	C187	
10377	James River Genco LLC	C540	
10378	CPI USA NC Southport	C541	
10380	Elizabethtown Power LLC	C542	
10382	Lumberton	C543	
10384	Edgecombe Genco LLC	C544	
1040	Whitewater Valley	C188	
1043	Frank E Ratts	C189	
10464	Black River Generation	C546	
1047	Lansing	C191	
1048	Milton L Kapp	C192	
10495	Rumford Cogeneration	C548	NENG_ME
10566	Chambers Cogeneration LP	C550	
10603	Ebensburg Power	C552	
10640	Stockton Cogen	C554	WEC_CALN
10641	Cambria Cogen	C555	
10670	AES Deepwater	C556	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
10671	AES Shady Point LLC	C557	
10672	Cedar Bay Generating Company LP	C558	
10675	AES Thames	C560	NENG_CT
10676	AES Beaver Valley Partners Beaver Valley	C561	
10678	AES Warrior Run Cogeneration Facility	C562	
1073	Prairie Creek	C193	
10743	Morgantown Energy Facility	C564	
10768	Rio Bravo Jasmin	C565	
10769	Rio Bravo Poso	C566	
10784	Colstrip Energy LP	C570	
108	Holcomb	C113	
1081	Riverside	C195	
1082	Walter Scott Jr Energy Center	C196	MIS_MIDA
10849	Silver Bay Power	C572	
1091	George Neal North	C197	
1104	Burlington	C198	
1122	Ames Electric Services Power Plant	C199	
113	Cholla	C114	
1131	Streeter Station	C200	
1167	Muscatine Plant #1	C201	
1217	Earl F Wisdom	C203	
1218	Fair Station	C204	
1241	La Cygne	C206	
1250	Lawrence Energy Center	C207	
1252	Tecumseh Energy Center	C208	
126	H Wilson Sundt Generating Station	C115	
127	Oklaunion	C116	ERC_WEST
1295	Quindaro	C209	
130	Cross	C117	
1355	E W Brown	C211	
1356	Ghent	C212	
136	Seminole	C118	
1364	Mill Creek	C216	
1374	Elmer Smith	C217	S_C_KY
1378	Paradise	C218	S_C_TVA
1379	Shawnee	C219	
1381	Kenneth C Coleman	C220	
1382	HMP&L Station Two Henderson	C221	
1383	Robert A Reid	C222	
1384	Cooper	C223	
1385	Dale	C224	
1393	R S Nelson	C225	S_D_WOTA
1552	C P Crane	C226	
1571	Chalk Point LLC	C229	
1572	Dickerson	C230	PJM_SMAC
1573	Morgantown Generating Plant	C231	
160	Apache Station	C119	
1619	Brayton Point	C234	
165	GRDA	C120	
1695	B C Cobb	C236	
1702	Dan E Karn	C237	
1710	J H Campbell	C238	
1720	J C Weadock	C239	
1723	J R Whiting	C240	
1731	Harbor Beach	C241	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
1733	Monroe	C243	MIS_LMI
1740	River Rouge	C244	
1743	St Clair	C245	
1745	Trenton Channel	C246	
1769	Presque Isle	C247	
1771	Escanaba	C248	
1825	J B Sims	C249	
1830	James De Young	C250	
1831	Eckert Station	C251	
1832	Erickson Station	C252	
1843	Shiras	C253	
1866	Wyandotte	C254	
1891	Syl Laskin	C255	
1893	Clay Boswell	C256	
1915	Allen S King	C258	
1961	Austin Northeast	C260	
1979	Hibbing	C261	
2008	Silver Lake	C262	
2018	Virginia	C263	
2022	Willmar	C264	
2049	Jack Watson	C265	
207	St Johns River Power Park	C121	
2076	Asbury	C267	
2079	Hawthorn	C268	
2080	Montrose	C269	
2094	Sibley	C270	
2098	Lake Road	C271	
2103	Labadie	C272	MIS_MO
2104	Meramec	C273	
2107	Sioux	C274	
2123	Columbia	C275	
2132	Blue Valley	C276	
2144	Marshall	C277	
2161	James River Power Station	C278	
2167	New Madrid	C279	
2168	Thomas Hill	C280	
2171	Missouri City	C282	
2187	J E Corette Plant	C283	
2240	Lon Wright	C284	
2277	Sheldon	C285	
2291	North Omaha	C286	
2324	Reid Gardner	C287	WECC_SNV
2364	Merrimack	C288	NENGREST
2367	Schiller	C289	
2378	B L England	C290	PJM_EMAC
2403	PSEG Hudson Generating Station	C292	
2408	PSEG Mercer Generating Station	C293	
2442	Four Corners	C295	
2451	San Juan	C296	
2526	AES Westover	C298	
2527	AES Greenidge LLC	C299	
2535	AES Cayuga	C300	NY_Z_C&E
2549	C R Huntley Generating Station	C301	
2554	Dunkirk Generating Plant	C302	
26	E C Gaston	C104	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
2706	Asheville	C304	
2712	Roxboro	C306	
2718	G G Allen	C309	S_VACA
2721	Cliffside	C311	
2727	Marshall	C312	
2790	R M Heskett	C314	
2817	Leland Olds	C315	MAP_WAUE
2823	Milton R Young	C316	
2824	Stanton	C317	MIS_MNWI
2828	Cardinal	C318	
2836	Avon Lake	C322	
2840	Conesville	C325	
2850	J M Stuart	C328	
2866	FirstEnergy W H Sammis	C331	
2876	Kyger Creek	C333	
2878	FirstEnergy Bay Shore	C334	
2914	Dover	C335	
2917	Hamilton	C336	
2935	Orrville	C337	
2936	Painesville	C338	
2952	Muskogee	C340	
2963	Northeastern	C341	
298	Limestone	C122	
3	Barry	C100	
3118	Conemaugh	C345	PJM_PENE
3122	Homer City Station	C346	
3130	Seward	C347	
3136	Keystone	C349	
3138	New Castle Plant	C350	
3140	PPL Brunner Island	C351	PJM_WMAC
3149	PPL Montour	C352	
3152	Sunbury Generation LP	C353	
3179	Hatfields Ferry Power Station	C355	
3181	FirstEnergy Mitchell Power Station	C356	
3287	McMeekin	C360	
3295	Urquhart	C361	
3297	Wateree	C362	
3298	Williams	C363	
3393	Allen Steam Plant	C367	
3396	Bull Run	C368	
3399	Cumberland	C369	
3403	Gallatin	C370	
3407	Kingston	C373	
3470	W A Parish	C375	
3497	Big Brown Power Company LLC	C376	
3775	Clinch River	C378	
3796	Bremo Bluff	C381	
3797	Chesterfield	C382	
3809	Yorktown	C384	
384	Joliet 29	C123	
3845	Transalta Centralia Generation	C385	WECC_PNW
3935	John E Amos	C386	
3943	FirstEnergy Fort Martin Power Station	C390	
3944	FirstEnergy Harrison Power Station	C391	
3948	Mitchell	C395	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
3954	Mt Storm	C396	
3992	Blount Street	C397	
4041	South Oak Creek	C398	
4042	Valley	C399	
4050	Edgewater	C400	
4072	Pulliam	C402	
4078	Weston	C403	
4125	Manitowoc	C404	
4127	Menasha	C405	
4140	Alma	C406	
4143	Genoa	C407	
4158	Dave Johnston	C410	
4162	Naughton	C411	
4259	Endicott Station	C412	
4271	John P Madgett	C413	
465	Arapahoe	C125	
469	Cherokee	C126	
47	Colbert	C105	
470	Comanche	C127	WECC_CO
477	Valmont	C128	
492	Martin Drake	C129	
4941	Navajo	C414	
50	Widows Creek	C106	
50039	Kline Township Cogen Facility	C580	
50130	G F Weaton Power Station	C581	
50366	University of Notre Dame	C588	
50388	Phillips 66 Carbon Plant	C590	WECC_SF
50397	P H Glatfelter	C592	
50410	Chester Operations	C594	
50611	WPS Westwood Generation LLC	C597	
50776	Panther Creek Energy Facility	C599	
508	Lamar Plant	C130	
50806	Stone Container Florence Mill	C601	
50835	TES Filer City Station	C602	
50879	Wheelabrator Frackville Energy	C603	
50888	Northampton Generating Company LP	C604	
50931	Yellowstone Energy LP	C606	
50951	Sunnyside Cogen Associates	C607	
50974	Scrubgrass Generating Company LP	C609	
50976	Indiantown Cogeneration LP	C610	
51	Dolet Hills	C107	
52007	Mecklenburg Power Station	C611	
52071	Sandow Station	C612	
525	Hayden	C132	
527	Nucla	C133	
54035	Roanoke Valley Energy Facililty I	C614	
54081	Spruance Genco LLC	C615	
54144	Piney Creek Project	C616	
54304	Birchwood Power	C621	
54408	UW Madison Charter Street Plant	C625	
54556	Corn Products Illinois	C626	
54634	St Nicholas Cogen Project	C627	
54677	CII Carbon LLC	C628	
54755	Roanoke Valley Energy Facility II	C629	
54775	University of Iowa Main Power Plant	C630	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
55076	Red Hills Generating Facility	C633	
55479	Wygen 1	C635	
55749	Hardin Generator Project	C636	
56	Charles R Lowman	C108	
56068	Elm Road Generating Station	C639	MIS_WUMS
56163	KUCC	C640	
56224	TS Power Plant	C641	WECC_NNV
56319	Wygen 2	C642	
564	Stanton Energy Center	C134	FRCC
56456	Plum Point Energy Station	C643	S_D_N_AR
56596	Wygen III	C645	WECC_WY
56609	Dry Fork Station	C646	
56611	Sandy Creek Energy Station	C647	
56671	Longview Power LLC	C649	PJM_AP
56708	CFB Power Plant	C650	
56786	Spiritwood Station	C652	MIS_MAPP
568	Bridgeport Station	C135	
56848	Haverhill North Cogeneration Facility	C210	
57046	Archer Daniels Midland Columbus	C654	
59	Platte	C109	SPP_NEBR
593	Edge Moor	C136	
594	Indian River Generating Station	C137	
60	Whelan Energy Center	C110	
6002	James H Miller Jr	C415	
6004	FirstEnergy Pleasants Power Station	C416	
6009	White Bluff	C417	S_D_REST
6016	Duck Creek	C418	
6017	Newton	C419	
6018	East Bend	C420	
6019	W H Zimmer	C421	
602	Brandon Shores	C138	
6021	Craig	C422	
6030	Coal Creek	C423	
6031	Killen Station	C424	
6034	Belle River	C425	
6041	H L Spurlock	C426	
6052	Wansley	C427	
6055	Big Cajun 2	C428	
6061	R D Morrow	C429	
6064	Nearman Creek	C430	
6065	Iatan	C431	SPP_N
6068	Jeffrey Energy Center	C432	
6071	Trimble County	C433	
6073	Victor J Daniel Jr	C434	
6076	Colstrip	C435	WECC_MT
6077	Gerald Gentleman	C436	
6082	AES Somerset LLC	C437	NY_Z_A&B
6085	R M Schahfer	C438	
6089	Lewis & Clark	C439	
6090	Sherburne County	C440	
6094	FirstEnergy Bruce Mansfield	C441	
6095	Sooner	C442	
6096	Nebraska City	C443	
6098	Big Stone	C444	
6101	Wyodak	C445	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
6106	Boardman	C446	
6113	Gibson	C447	MIS_INKY
6124	McIntosh	C448	
6136	Gibbons Creek	C449	
6137	A B Brown	C450	
6138	Flint Creek	C451	
6139	Welsh	C452	
6146	Martin Lake	C453	
6147	Monticello	C454	
6155	Rush Island	C455	
6165	Hunter	C456	WECC_UT
6166	Rockport	C457	
6170	Pleasant Prairie	C458	
6177	Coronado	C459	
6178	Coleto Creek	C460	
6179	Fayette Power Project	C461	ERC_REST
6180	Oak Grove	C462	
6181	J T Deely	C463	
6183	San Miguel	C464	
6190	Brame Energy Center	C465	SPP_SE
6193	Harrington	C466	
6194	Tolk	C467	SPP_SPS
6195	Southwest Power Station	C468	
6204	Laramie River Station	C469	
6213	Merom	C470	
6225	Jasper 2	C471	
6248	Pawnee	C473	
6249	Winyah	C474	
6250	Mayo	C475	
6254	Ottumwa	C476	MIS_IA
6257	Scherer	C477	
6264	Mountaineer	C478	
628	Crystal River	C139	
641	Crist	C140	
642	Scholz	C141	
643	Lansing Smith	C142	
645	Big Bend	C143	
6469	Antelope Valley	C480	
6481	Intermountain Power Project	C481	
663	Deerhaven Generating Station	C144	
6639	R D Green	C482	
6641	Independence	C483	
6648	Sandow No 4	C484	
6664	Louisa	C485	
667	Northside Generating Station	C145	
6705	Warrick	C486	
676	C D McIntosh Jr	C146	
6761	Rawhide	C487	
6768	Sikeston Power Station	C488	
6772	Hugo	C489	
6823	D B Wilson	C490	
703	Bowen	C147	S_SOU
7030	Twin Oaks Power One	C491	
708	Hammond	C148	
709	Harllee Branch	C149	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
7097	J K Spruce	C492	
7210	Cope	C493	
7213	Clover	C494	PJM_Dom
727	Mitchell	C150	
733	Kraft	C152	
7343	George Neal South	C496	
7504	Neil Simpson II	C497	
753	Crisp Plant	C153	
7549	Milwaukee County	C499	
7737	Cogen South	C501	
7790	Bonanza	C502	
7902	Pirkey	C503	
8	Gorgas	C102	
8023	Columbia	C504	
8042	Belews Creek	C505	
8066	Jim Bridger	C672	
8069	Huntington	C506	
8102	General James M Gavin	C507	
8219	Ray D Nixon	C508	
8222	Coyote	C509	
8223	Springerville	C510	WECC_AZ
8224	North Valmy	C511	
8226	Cheswick Power Plant	C512	
856	E D Edwards	C154	
861	Coffeen	C155	
87	Escalante	C112	WECC_NM
874	Joliet 9	C158	
876	Kincaid Generation LLC	C159	
879	Powerton	C160	
883	Waukegan	C161	
884	Will County	C162	PJM_COMD
887	Joppa Steam	C164	
889	Baldwin Energy Complex	C165	
891	Havana	C166	
892	Hennepin Power Station	C167	
898	Wood River	C169	
963	Dallman	C170	
976	Marion	C171	
983	Clifty Creek	C173	
990	Harding Street	C175	
994	AES Petersburg	C177	
995	Bailly	C178	
997	Michigan City	C179	
83551	Plant Ratcliffe - the Kemper IGCC Project	C633	
55360	Two Elk Generating Station	C634	
56664	Greene Energy Resource Recovery Project	C678	
70194	Genesee #3	C661	
70195	Genesee	C661	
70243	HR Milner	C662	
70269	Keephills	C663	CN_AB
70309	Lingan	C664	
70035	Belledune	C658	CN_NB
70441	Poplar River	C665	
70449	Pt. Aconi	C666	CN_NS
70450	Pt. Tupper	C667	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
70514	Shand	C668	
70517	Sheerness	C669	
70056	Boundary Dam	C659	CN_SK
70562	Sundance	C670	
70587	Trenton NS	C671	
3264	W S Lee	C358	
3406	Johnsonville	C372	
3803	Chesapeake	C383	
		C676	NY_Z_F
2480	Danskammer Generating Station	C297	NY_Z_G-I
		C675	NY_Z_D
2837	FirstEnergy Eastlake	C323	PJM_ATSI
		C677	S_D_AMSO
10002	ACE Cogeneration Facility	C513	WECC_SCE
70058	Brandon G.S.	C660	CN_MB
1353	Big Sandy	C210	PJM_West

*If IPM elects to build a new coal plant, that coal plant will be assigned to a particular IPM region. Therefore, the base case modeling relies on a particular existing plant in that region – generally one considered to be representative of average transportation cost for plants in that region – and uses that plant's transportation cost as a surrogate for coal transportation cost for a projected new coal plant.

9.1.3 Coal Quality Characteristics

Coal varies by heat content, SO_2 content, HCl 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, subbituminous, 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
Subbituminous	> 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.5.13 on the heat, HCl, 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)[82].

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, chlorine, and ash content of the coal used was obtained along with mercury content.

The 1998-2000 ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content, ash content, chlorine 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.5.13, 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, HCl, 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 coal characteristics of Canadian coal supply regions are based on the coal characteristics of the adjacent US coal supply regions. The resulting values are shown in Table 9-5.

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)	HCl Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)
AB	SA	16.12	0.59	5.29	5.47	0.009	214.9
	SB	15.60	0.94	6.06	6.94	0.013	211.0
	SD	15.00	1.43	5.35	11.60	0.008	214.9
AL	BB	25.50	1.09	4.18	9.76	0.012	204.7
	BE	24.00	2.68	12.58	10.70	0.028	204.7
AN	BG	22.00	4.23	9.36	7.83	0.079	202.8
AZ	BB	21.50	1.05	5.27	7.86	0.067	207.1
BC	BD	21.40	1.40	6.98	8.34	0.096	205.4
CG	BB	22.74	0.90	4.09	8.42	0.021	209.6
	SB	20.00	0.93	2.03	7.06	0.007	209.6
CR	BB	23.36	1.05	5.27	7.86	0.067	209.6
CU	BB	23.56	0.86	4.01	7.83	0.009	209.6
IL	BE	23.75	2.25	6.52	6.61	0.214	203.1
	BG	23.50	4.56	6.53	8.09	0.113	203.1
	BH	22.00	5.58	5.43	9.06	0.103	203.1
IN	BB	22.00	1.00	2.29	6.67	0.050	203.1
	BE	22.70	2.31	5.21	7.97	0.036	203.1
	BG	22.40	4.27	7.20	8.22	0.028	203.1
	BH	22.40	6.15	7.11	8.63	0.019	203.1
KE	BB	25.00	1.04	4.79	6.41	0.112	206.4

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

Coal Supply Region	Coal Grade	Heat Content (MMBtu/Ton)	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/Tbtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)
	BD	24.80	1.44	5.97	7.45	0.087	206.4
	BE	24.64	2.12	7.93	7.71	0.076	206.4
KS	BG	22.00	4.84	4.09	8.47	0.133	202.8
KW	BD	23.80	1.56	5.56	6.19	0.280	203.1
	BG	23.80	4.46	6.90	8.01	0.097	203.1
	BH	23.00	5.73	8.16	10.21	0.053	203.1
LA	LE	13.80	2.49	7.32	17.15	0.014	212.6
MD	BD	23.00	1.55	7.82	9.53	0.029	204.7
	BE	23.20	2.78	15.62	11.70	0.072	204.7
ME	LE	12.97	1.83	11.33	11.69	0.019	219.3
MO	BG	22.00	4.54	5.91	9.46	0.023	202.8
MP	SA	18.20	0.62	4.24	3.98	0.007	215.5
	SD	17.20	1.49	4.53	10.13	0.006	215.5
MS	LE	10.39	2.76	12.44	21.51	0.018	212.6
MT	BB	20.90	1.05	5.27	7.86	0.067	215.5
ND	LE	13.10	2.27	8.30	12.85	0.014	219.3
NS	SB	19.60	0.89	4.60	14.51	0.014	209.2
	SE	18.40	1.90	8.65	23.97	0.008	209.2
OH	BE	24.20	3.08	18.70	7.08	0.075	204.7
	BG	24.10	3.99	18.54	8.00	0.071	204.7
	BH	24.20	6.43	13.93	9.13	0.058	204.7
OK	BG	22.00	4.65	26.07	13.54	0.051	202.8
PC	BE	24.41	2.57	17.95	9.23	0.096	204.7
	BG	24.40	3.79	21.54	9.59	0.092	204.7
PW	BE	26.00	2.51	8.40	5.37	0.090	204.7
	BG	25.40	3.69	8.56	6.48	0.059	204.7
SK	LD	13.82	1.51	7.53	11.57	0.014	219.3
	LE	10.58	2.76	12.44	21.51	0.018	215.3
TN	BB	26.20	1.14	3.78	10.35	0.083	206.4
	BE	25.23	2.13	8.43	6.47	0.043	206.4
TX	LE	13.47	3.00	14.65	25.65	0.020	212.6
	LG	12.47	3.91	14.88	25.51	0.036	212.6
	LH	10.68	5.67	30.23	23.95	0.011	212.6
UT	BA	23.00	0.67	4.37	7.39	0.015	209.6
	BE	23.90	2.34	9.20	7.41	0.095	209.6
VA	BB	25.90	1.05	4.61	6.97	0.054	206.4
	BD	25.20	1.44	5.67	7.97	0.028	206.4
	BE	25.00	2.09	8.40	8.05	0.028	206.4
WG	BB	22.00	1.13	1.82	5.58	0.005	214.3
	SD	18.80	1.33	4.33	10.02	0.008	214.3
WH	SA	17.60	0.58	5.61	5.47	0.010	214.3
WL	SB	16.79	0.94	6.44	6.50	0.012	214.3
WN	BE	25.35	2.55	10.28	7.89	0.092	204.7
	BH	25.15	6.09	8.82	9.62	0.045	204.7
WS	BB	24.40	1.09	5.75	9.15	0.091	206.4
	BD	24.50	1.32	8.09	9.25	0.098	206.4
	BE	23.83	1.94	8.80	9.89	0.102	206.4

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.5.13 are shown in Table 9-6. 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 9-6 Example of Coal Assignments Made in EPA Base Case

Plant Name	Unique ID	SIP SO_2 Limit (lbs/MMBtu)	Scrubber?	Fuels Allowed
Mt Storm	3954_B_3	0.15	Yes	BA,BB,BD
Mitchell	3948_B_1	1.2	Yes	BA,BB,BD,BE,BG,BH
Scherer	6257_B_1	1.2	Yes	BA,BB,BD,BE,BG,BH,SA,SB, SD,SE
Newton	6017_B_1	0.5	No	BA,SA
Weston	4078_B_4	0.1	Yes	BA,SA,SB
Sandow No 4	6648_B_4	1.2	Yes	LA,LD,LE,LG,LH
Monticello	6147_B_3	1.2	Yes	LA,LD,LE,LG,LH,SA,SB,SD,SE
Laramie River Station	6204_B_3	0.2	Yes	LA,SA,SB
Big Cajun 2	6055_B_2B1	0.38	No	SA
W A Parish	3470_B_WAP8	0.36	Yes	SA,SB,SD,SE

9.2 Coal Supply Curves

9.2.1 Nature of Supply Curves Developed for EPA Base Case v.5.13

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.5.13. 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 36 coal supply regions (described above in sections 0) and 14 coal grades (described above in section 9.1.3). The combined code list is shown in Table 9-7 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 9-7) for forecast years 2016, 2018, 2020, 2025, 2030, 2040, and 2050.

Table 9-7 Basin-Level Groupings Used in Preparing v.5.13 Coal Supply Curves

Table 9-7 Basin Level Groupings Used in Preparing v.5.13 Coal Supply Curves

			Bituminous						Lignite				Subbituminous			
Coal Supply Region	Geo Region	Geo. Sub-Region	BA	BB	BD	BE	BG	BH	LD	LE	LG	LH	SA	SB	SD	SE
AB	Canada	Alberta, Canada											x	x	x	
AK	West	Northwest	x										x			
AL	Appalachia	Southern Appalachia		x		x										
AN	Interior	West Interior					x									
AZ	West	Southwest		x												
BC	Canada	British Columbia			x											
CG	West	Rocky Mountain		x										x		
CR	West	Rocky Mountain		x												
CU	West	Rocky Mountain		x												
IL	Interior	East Interior (Illinois Basin)				x	x	x								
IN	Interior	East Interior (Illinois Basin)		x		x	x	x								
KE	Appalachia	Central Appalachia		x	x	x										
KS	Interior	West Interior					x									
KW	Interior	East Interior (Illinois Basin)			x		x	x								
LA	Interior	Gulf Lignite								x						
MD	Appalachia	Northern Appalachia			x	x										
ME	West	Dakota Lignite								x						
MO	Interior	West Interior					x									
MP	West	Powder River Basin											x		x	
MS	Gulf	Gulf Lignite Coast								x						
MT	West	Western Montana		x												
ND	West	Dakota Lignite								x						
NS	West	Southwest												x		x
OH	Appalachia	Northern Appalachia				x	x	x								
OK	West	West Interior					x									
PC	Appalachia	Northern Appalachia				x	x									
PW	Appalachia	Northern Appalachia				x	x									
SK	Canada	Saskatchewan							x	x						
TN	Appalachia	Central Appalachia		x		x										
TX	Interior	Gulf Lignite								x	x	x				
UT	West	Rocky Mountain	x			x										
VA	Appalachia	Central Appalachia		x	x	x										
WG	West	Western Wyoming		x											x	
WH	West	Powder River Basin											x			
WL	West	Powder River Basin												x		
WN	Appalachia	Northern Appalachia				x		x								
WS	Appalachia	Central Appalachia		x	x	x										

9.2.2 Cost Components in the Supply Curves

Costs are represented as total cash costs, which is a combination of a mine's operating cash costs plus royalty & levies. These costs are estimated on a Free on Board (FOB) basis at the point of sale. Capital costs (either expansionary or sustaining) are not included in the cash cost estimate. We believe that total cash cost is the best metric for the supply curves as coal prices tend to be ultimately determined by the incremental cost of production (i.e. total cash cost).

Operating cash cost

These are the direct operating cash costs and includes, where appropriate, mining, coal preparation, product transport, and overheads. No capital cost component or depreciation & amortization charge is included. Operating cash costs consist of the following elements:

- Mining costs - Mining costs are the direct cost of mining coal and associated waste material for surface and underground operations. It includes any other mine site costs, such as ongoing rehabilitation / reclamation, security, community development costs. It also includes the cost of transporting raw coal from the mining location to the raw coal stockpile at the coal preparation plant.
- Coal preparation - The cost of coal preparation includes raw coal stockpile reclaim, crushing and screening, washing and marketable coal product stockpiling (if applicable).
- Transport - This covers all transport costs of product coal to point of sale. Transport routes with multiple modes (e.g. truck and rail) are shown as total cost per marketable ton for all stages of the transport route. Loading charges are included in this cost if relevant.
- Overheads - This is any off mine site general and administration overheads that are essential to the production and sale of a mine's coal product. Examples would be essential corporate management or a sales and marketing charge.

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. Further information on operating cost methodology and assumptions can be found in Attachment 9-1.

Royalties and Levies

These include, where appropriate, coal royalties, mine safety levies, health levies, industry research levies and other production taxes.

9.2.3 Procedures Employed in Determining Mining Costs

The total cash costs of mines have been estimated in current year terms using public domain information including; geological reports, reported statistics on production, labor and input costs, and company reports. The estimates have been validated by reference to information gained by visits to operations, and discussions with industry participants.

Because the estimates are based only on public information and analysis, and do not represent private knowledge of an operation's actual costs, there may be deviations from actual costs. In instances where confidential information is held by Wood Mackenzie, it has not been used to produce the published estimates. Several methods are employed for cost estimation depending on the availability of information and the diversity of mining operations. When possible, Wood Mackenzie analysts developed 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 operating cash costs.

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. 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 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.

9.2.4 Procedure Used In Determining Mine Productivity

Projected production and stripping ratios 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.

9.2.5 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 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)[83] estimates to ensure that they do not exceed the DRB estimates.

9.2.6 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 and designated with the letter "N" in the "Step Name" field of the supply curves. 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.

In the IL basin, there is a significant amount of mine projects announced and/or underway that will be completed and available by 2016. These "on the way" mines are designated as existing mines in the "step name" field as they already are, or expected to be, available by the first model run year of 2016. Wood Mackenzie has also identified technical coal reserves that may be commercial in the longer-term, but would most likely not be developed until after the completion of mine development already underway or announced. Therefore, the new mines reflecting these additional reserves are not available until 2018.

9.2.7 Other Notable Procedures

<u>Currency Assumptions</u>

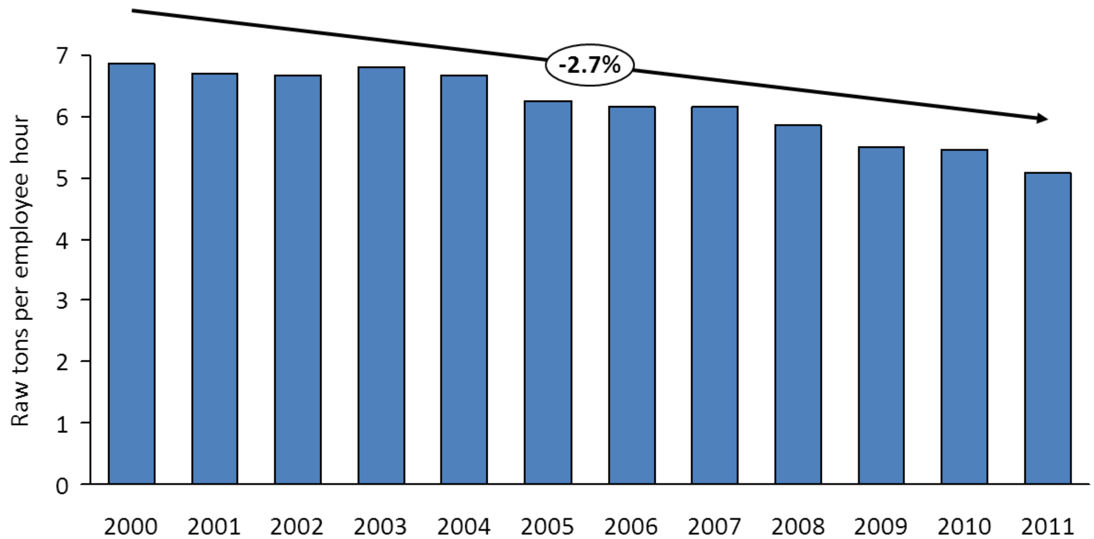
For consistency with the cost basis used in EPA Base Case v.5.13, costs are converted to real 2011$.

<u>Future Cost Adjustments</u>

Changes in mine productivity are a key factor impacting the evolution of costs over time. In general, mine productivity is expected to continue to decline – in large part due to worsening geology and more difficult to mine reserves Productivity has declined at -2.7% CAGR from 2000-2011 as shown in Figure 9-2.

[83] Posted by the Energy Information Administration (EIA) in its Coal Production Report.

Figure 9-2 Coal Mine Productivity (2000-2011)



Source: U.S. Department of Labor, Mine Safety and Health Administration

Figure 9-3 Average Annual Cost Growth Assumptions by Region (2012-2050)

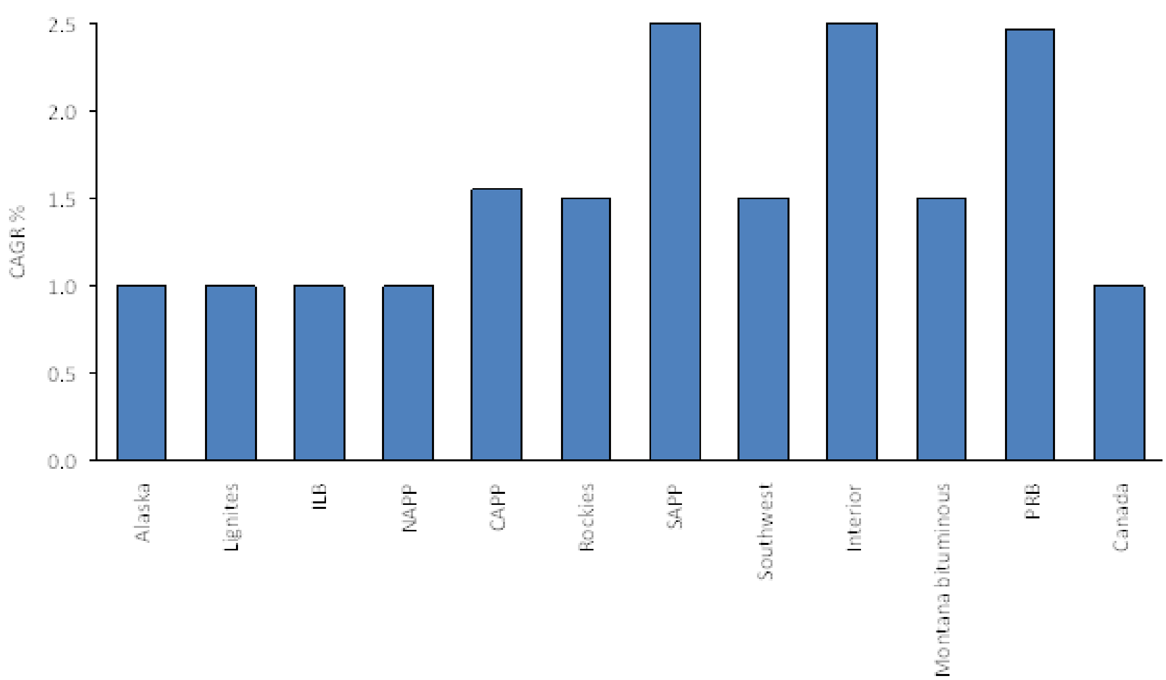


Figure 9-3 shows the compounded average annual growth rate (CAGR) of mining costs by basin over the forecast period. It should be noted that cost increases will ultimately be linked to market demand (as demand grows, the faster the rate of depletion of lower cost reserves). Costs in some supply basins are expected to increase more quickly than others due to issues such as mining conditions, productivity, infrastructure limitations, etc. Region-specific information can be found in section 9.2.9.

Supply Growth Limitations

To the maximum extent possible, the IPM model is set up to determine the optimal volume of coal supply which can be profitably supplied. For two of the lower cost basins (Powder River and Illinois basins), maximum production capacities are included as constraints (production ceilings) to more accurately reflect the upper bound of what could be produced in a given year. Those limits, represented in millions of tons per year, are shown in Figure 9-4 below. These ceilings are necessary to guard against modeling excess annual production capacity in certain basins. For instance, in the PRB, several of the “new” mines reflect expansion mines that would not be developed until the initial mine is further depleted. In this case, the production ceiling helps safeguard against a modeling scenario that would simultaneously produce from both of these mines.

Figure 9-4 Maximum Annual Coal Production Capacity

Maximum Thermal Coal Production Capacity per Year (million tons)

	2016	2018	2020	2025	2030	2040	2050
ILB	165.5	190	203.4	220.1	239.5	254.6	254.6
PRB	509	525.5	552.5	572.3	609.5	609.5	609.5

9.2.8 Supply Curve Development

The description below describes the development of the coal supply curves. The actual coal supply curves can be found www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html. For illustrative purposes, there is also an excerpt of the coal supply curves in Table 9-24 of this chapter.

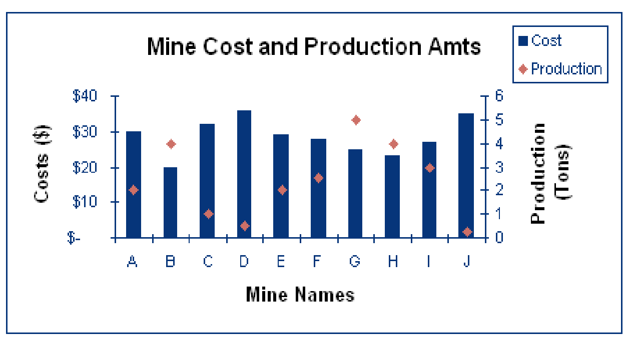
Once costs are estimated for all new or existing mines, they are sorted by cash cost, lowest to highest, and plotted cumulatively by production to form a supply curve. The supply curve then represents all mines – new or existing as well as both underground and surface mines– irrespective of market demand. 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 9-5 and Figure 9-6 below.

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

Key

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

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



In the table and graph above, mine costs and production are sorted alphabetically by mine name. To develop a supply curve from the above table the values must be sorted by mine costs from lowest to highest. A new column for cumulative production is added, and then a supply curve graph is created which shows the costs on the ‘Y’ axis and the cumulative production on the ‘X’ axis. Notice below that the curve contains all mines – new or existing as well as both underground and surface mines. The resulting curve is a continuous supply curve but can be modified to show costs as a stepped supply curve. (Supply curves in stepped format are used in linear programming models like IPM.) See Figure 9-7 for a stepped version of the supply curve example shown in Figure 9-6. 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.

Figure 9-6 Illustration of Final Step in Developing a Cumulative Coal Supply Curve

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

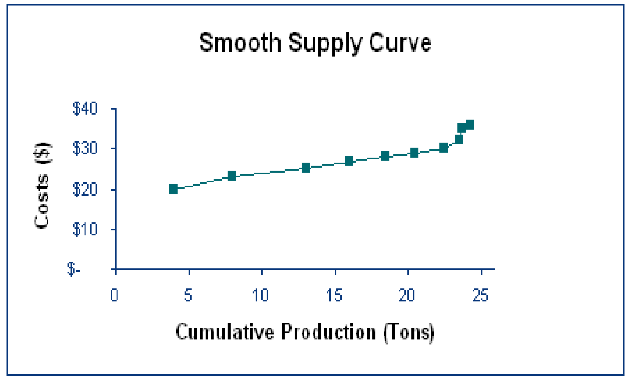
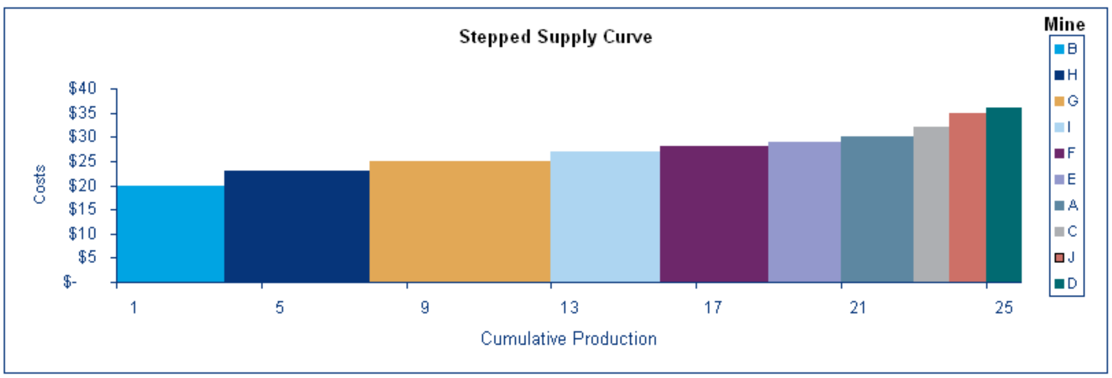


Figure 9-7 Example Coal Supply Curve in Stepped Format



		PRODUCTION AMOUNT									
MINE NAME →		B	H	G	I	F	E	A	C	J	D
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

9.2.9 EPA Base Case v.5.13 Assumptions and Outlooks for Major Supply Basins

Powder River Basin (PRB)

The PRB is somewhat unique to other US coal basins; in that producers have the ability to add significant production volumes relatively easily and at a profit. That said, the decisions on production volumes are largely based on the market conditions, namely the price. For instance, in a low price environment producers tend to moderate production volumes to maintain attractive prices, and choose to ramp up production when prices are higher. The evolution of costs in the PRB will be strongly correlated to the rate at which producers ramp up production at existing mines, which as indicated will depend on market conditions.

Wood Mackenzie anticipates productivity at most existing PRB mining operations to decline at very modest rates over the forecast horizon, with increasing strip ratios at least partly offset by improved usage of labor and capital. As most PRB mines are progressing downward, the ratios of overburden to coal (strip ratios) will increase in the future. The productivity of new mines will be quite low during the early stages of their life span.

Mining at several locations is steadily proceeding production westward toward the Joint Line railroad and, at current and forecasted levels of production, around 2019 several mines are expected to eventually reach the line. This event will result in a costly movement across the railroad, requiring significant capital investment and reduced production as the transition is made. During the move across the Joint Line railroad, strip ratios will spike and productivity will fall as new box cuts are created.

Illinois Basin (ILB)

Production costs in the Illinois basin have been steadily decreasing in recent years as new low cost mines are opened using more efficient longwall mining techniques. Wood Mackenzie expects that average costs will continue to decline as additional new mines are developed. However, as new low cost mines are brought on, higher cost mines will be unable to compete. In the long-term, the shape of the ILB supply curve is expected to decrease in cost and increase in production capacity.

Given its large scale growth potential, investments in rail infrastructure development will have to keep pace. While Wood Mackenzie expect there to be some bottlenecks in expanding transportation in the basin early on, they project that once utilities begin committing to taking ILB coal, railroads will make the necessary changes to accommodate the change. However, there is a risk that rail infrastructure in the basin will not be able to keep up with the rate of growth in ILB which could limit the region's otherwise strong growth potential.

Central Appalachia (CAPP)

Geologic conditions in the CAPP region are challenging, with thin seams and few underground reserves amenable to more efficient longwall mining techniques. Costs of production in CAPP have risen substantially in recent years as the region has struggled with mining thinner seams as reserves deplete, mining accidents have led to increased inspections, and mine permitting has become increasingly difficult as opposition to surface mining intensifies – with the revocation of some section 404 permits that regulate the discharge into US waterways. Since surface mining is the lowest cost form of production in CAPP, reduced growth in surface mining operations is adding to increasing cost in the region

As producers cut back on production over the course of 2012 in order to manage the falling demand, productivity suffered and production costs per ton in the region rose roughly 10%. In an effort to retain margins, producers implemented a variety of tactics to try to keep production costs from continuing to increase; including, shifting more production to lower cost operations and selling lesser quality raw coal to save on coal preparation/washing costs.

Northern Appalachia (NAPP)

Mining cost escalation in NAPP has slowed considerably recently. Future cost for the basin as a whole will depend largely on the development of new reserve areas.

Northern Appalachia has an estimated 5 billion short tons (Bst) of thermal coal reserves. However, only about 2.3 Bst is associated with currently operating mines and 90 Mst of that with existing mines that are idled. Many major producers within the region are within years of depleting currently assigned reserves.

9.3 Coal Transportation

The description below describes the transportation matrix. The actual transportation matrix can be found www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html. For illustrative purposes, there is also an excerpt of the transportation matrix in Excerpt from Table 9-23 of this chapter.

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 for most modes of coal transportation 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 March 2012, when the coal transportation rate assumptions for EPA Base Case v.5.13 were finalized. The forecasted changes in transportation rates during the 2016-2050 forecast period reflect expected changes in long-term equilibrium transportation rate levels, including the long-term market dynamics that will drive these pricing levels.

All rates are represented in 2011 real dollars.

9.3.1 Coal Transportation Matrix Overview

Description

In previous versions of EPA Base Case using IPM, the coal transportation matrix connected coal supply regions with coal demand regions that represented the aggregated coal demand from several coal-fired generating plants. In EPA Base Case v.5.13, the demand side of the coal transportation matrix has been expanded, so that each of the approximately 560 U.S. and Canadian coal-fired generating plants included in EPA Base Case v.5.13 is individually represented in the coal transportation matrix. This allows the coal transportation routings, coal transportation distances, and coal transportation rates associated with each individual coal-fired generating plant to be estimated more accurately in EPA Base Case v. 5.13.

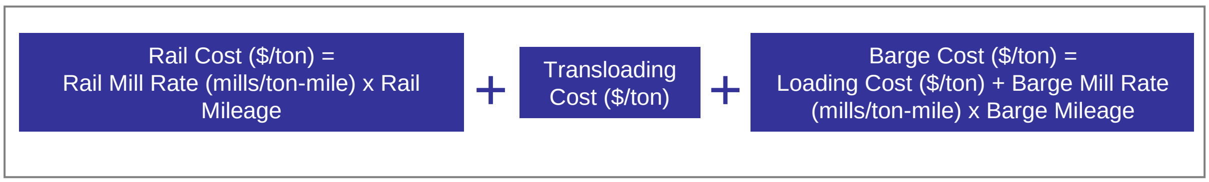
The coal transportation matrix shows the total coal transportation rate which is expected to be required to transport coal from selected coal supply regions to each individual coal-fired generating plant.

The coal supply regions associated with each coal-fired generating plant in EPA Base Case v.5.13 are largely unchanged from previous versions of IPM. The coal supply regions associated with each coal-fired generating plant are the coal supply regions which were supplying each plant as of late 2011, have supplied each plant in previous years, or are considered economically and operationally feasible sources of additional coal supply during the forecast period in EPA Base Case v. 5.13 (2016-2050.) A more detailed discussion of the coal supply regions can be found in previous sections.

Methodology

Each coal supply region and coal-fired generating plant 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 9-8.

Figure 9-8 Calculation of Multi-Mode Transportation Costs (Example)



9.3.2 Calculation of Coal Transportation Distances

Definition of applicable supply/demand regions

Coal-fired generating plants are linked to coal supply regions based on historical coal deliveries, as well as based on the potential for new coal supplies to serve each coal-fired generating plant going forward. A generating plant will almost always have transportation links with more than one supply region, depending on the various coal types that can be physically delivered and burned at that particular plant. On average, each coal-fired generating plant represented in IPM is linked with about nine coal supply regions. Some plants may have more than the average number of transportation links and some may have fewer, depending on the location of each plant, the transportation modes available to deliver coal to each plant, the boiler design and emissions control technologies associated with each plant, and other factors that affect the types of coal that can be burned at each plant.

For "mine-mouth" plants (plants for which the current coal supply is delivered from a single nearby mine, generally by conveyor belt or using truck transportation) that are 200 MW or larger, Hellerworx and Tetratech have estimated the cost of constructing facilities that would allow rail delivery of alternative coal supplies, and the transportation rates associated with the delivery of alternative coal supplies. This includes the construction of rail spurs (between one and nine miles in length depending on the proximity of each plant to existing railroad lines) to connect each plant with existing railroad lines.

Transportation Links for Existing Coal-Fired Plants

Transportation routings from particular coal supply regions to particular coal-fired generating plants were developed based on third-party software[84] and other industry knowledge available to Hellerworx and Tetratech. Origins for each coal supply region were based on significant mines or other significant

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

delivery points within the supply region, and the destination points were plant-specific for each coal-fired generating plant represented in IPM. 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

Transportation links for new coal-fired plants that were under construction as of March 2012 were developed using the same methodology as for existing plants, and these committed new plants were included in IPM as of their expected date of commercial operation.

Coal transportation costs for new coal-fired plants not yet under construction (i.e., coal transportation costs for new coal plants modeled by IPM) were estimated by selecting an existing coal plant within each IPM Region whose coal supply alternatives, and coal transportation costs, were considered representative of the coal supply alternatives and coal transportation costs that would likely be faced by new coal plants within that same IPM Region. 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, as of March 2012, the differential between rates at captive plants and rates at competitively-served plants was relatively narrow. 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 (seeTable 9-8), 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 9-8 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, 400-649 miles, and 650+ 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 2011 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). The practical effect of this is that CSX and NS do not compete aggressively at the limited number of plants that have access to both major railroads, and the rates for high-cost competitive plants tend to be similar to the rates for captive plants. Table 9-9 presents the 2012 eastern rail rates.

Table 9-9 Assumed Eastern Rail Rates for 2012
(2011 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	85	85	72
200-299	71	71	60
300-399	69	69	59
400-649	61	61	52
650+	43	43	37

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 9-10 depicts 2012 rail rates in the Midwest.

Table 9-10 Assumed Midwestern Rail Rates for 2012
(2011 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	85	85	72
200-299	67	67	57
300-399	49	49	42
400-649	46	46	39
650+	43	43	37

Rates Applicable to Western Moves

Rail moves within the Western U.S. are handled predominately by BNSF and UP. Due to industry concerns about potential future regulation of carbon dioxide (CO_2) emissions and other factors, it now appears very unlikely that the CP will construct a third rail line into the PRB, so this analysis assumes the PRB will continue to be served only by BNSF and UP. 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 , 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. In the west, there are enough plants that have access to both BNSF and UP or a neutral carrier that the western railroads are concerned of losing coal volume to the competing railroad, and do offer more of a rate discount to plants that can access both railroads (e.g., high-cost competitive).

Non-PRB Coal Moves

The assumed non-PRB western rail rates for 2012 are shown in Table 9-11.

Table 9-11 Assumed Non-PRB Western Rail Rates for 2012
(2011 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	53	45	45
300+	28	25	25

The assumed PRB western rail rates for 2012 are available in Table 9-12.

PRB Moves Confined to BNSF/UP Rail Lines

Table 9-12 Assumed PRB Western Rail Rates for 2012
(2011 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	32	27	27
300+	26	23	23

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 $2.20 per ton or 41 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 9-13 are expected long-term equilibrium levels reflective of current rates as of March 2012, and expected changes in labor costs, fuel prices, and steel prices.

Table 9-13 Assumed Truck Rates for 2012
(2011 Real Dollars)

Market	Loading Cost ($/ton)	Transport (mills/ton-mile)
All Markets	1.00	120

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 9-14 are expected long-term equilibrium levels reflective of current rates as of March 2012, and expected changes in labor costs, fuel prices, and steel prices.

Table 9-14 Assumed Barge Rates for 2012
(2011 Real Dollars)

Type of Barge Movement	Loading Cost ($/ton)	Transport (mills/ton-mile)
Upper Mississippi River, and Downstream on the Ohio River System	2.70	9.7
Upstream on the Ohio River System	2.45	11.5
Lower Mississippi River	2.70	6.9

Notes:

1. The Upper Mississippi River is the portion of the Mississippi River north of St. Louis.
2. The Ohio River System includes the Ohio, Big Sandy, Kanawha, Allegheny, and Monongahela Rivers.
3. The Lower Mississippi River is the portion of the Mississippi River south of St. Louis.

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.

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.5.13, 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. The assumed costs are summarized in

Excerpt from Table 9-23.

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 9-15.

Table 9-15 Assumed Other Transportation Rates for 2012 (2011 Real Dollars)

Type of Transportation	Rate ($/ton)
Rail-to-Barge Transfer	1.50
Rail-to-Vessel Transfer	2.00
Truck-to-Barge Transfer	2.00
Rail Switching Charge for Short line	2.00
Conveyor	1.00

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 33% of the rail industry's operating costs in 2010, and fuel accounted for an additional 18%. The remaining 49% of the rail industry's costs relate primarily to locomotive and railcar ownership and maintenance, and track construction and maintenance.

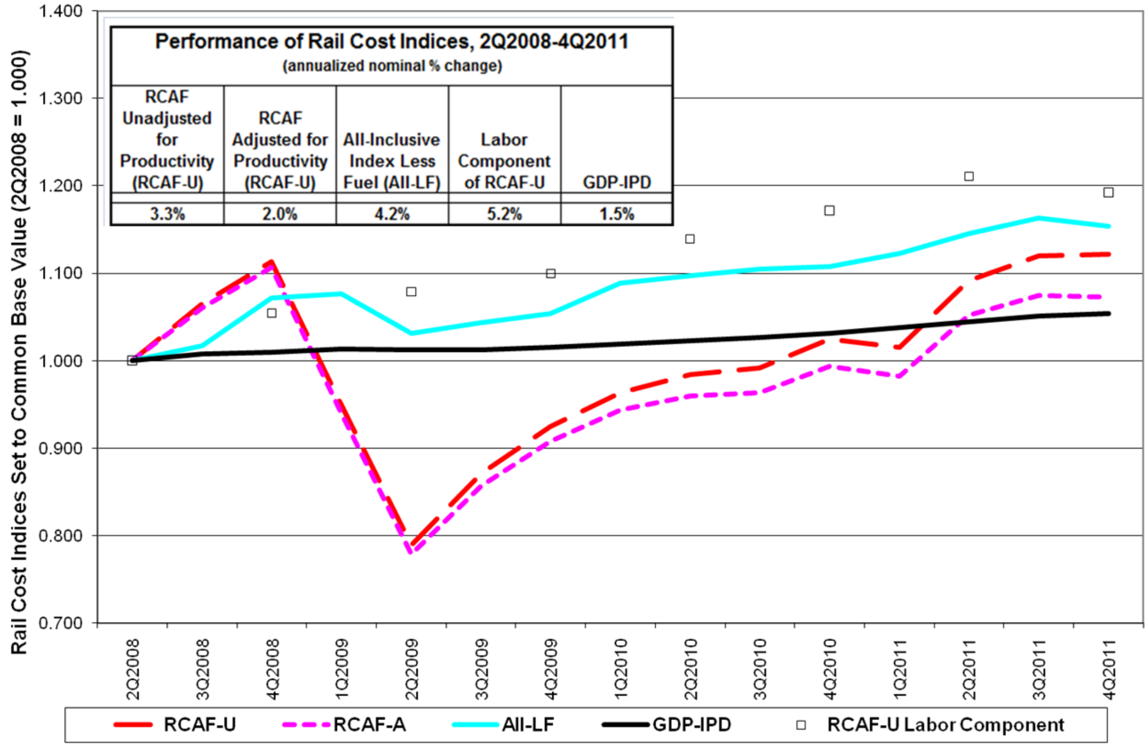
The RCAF[85] Unadjusted for Productivity (RCAF-U), which tracks operating expenses for the rail industry, increased at an annualized rate of 3.3%/year between the second quarter of 2008 and the fourth quarter of 2011, see Table 9-9, more than double the increase of 1.5%/year in general inflation (GDP-IPD) over the same period. This is largely the result of unusually steep increases in labor costs, which reflected the effect of new labor agreements negotiated prior to the economic downturn that occurred in late 2008 and 2009. Hellerworx expects that going forward, the rail industry's labor costs will increase at a more moderate rate (assumed to be 1% more than overall inflation), which is more in line with longer-term historical increases in these costs.

According to data from the AAR, the net change in the rail industry's fuel costs between 2Q2008 and 4Q2011 was a nominal decline of about 9% (or an annualized decline of about 2.6% per year. Over the same time period, equipment and other costs for the rail industry increased by an average of about 2.0% per year, only slightly faster than overall inflation of 1.5% per year.

[85] 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

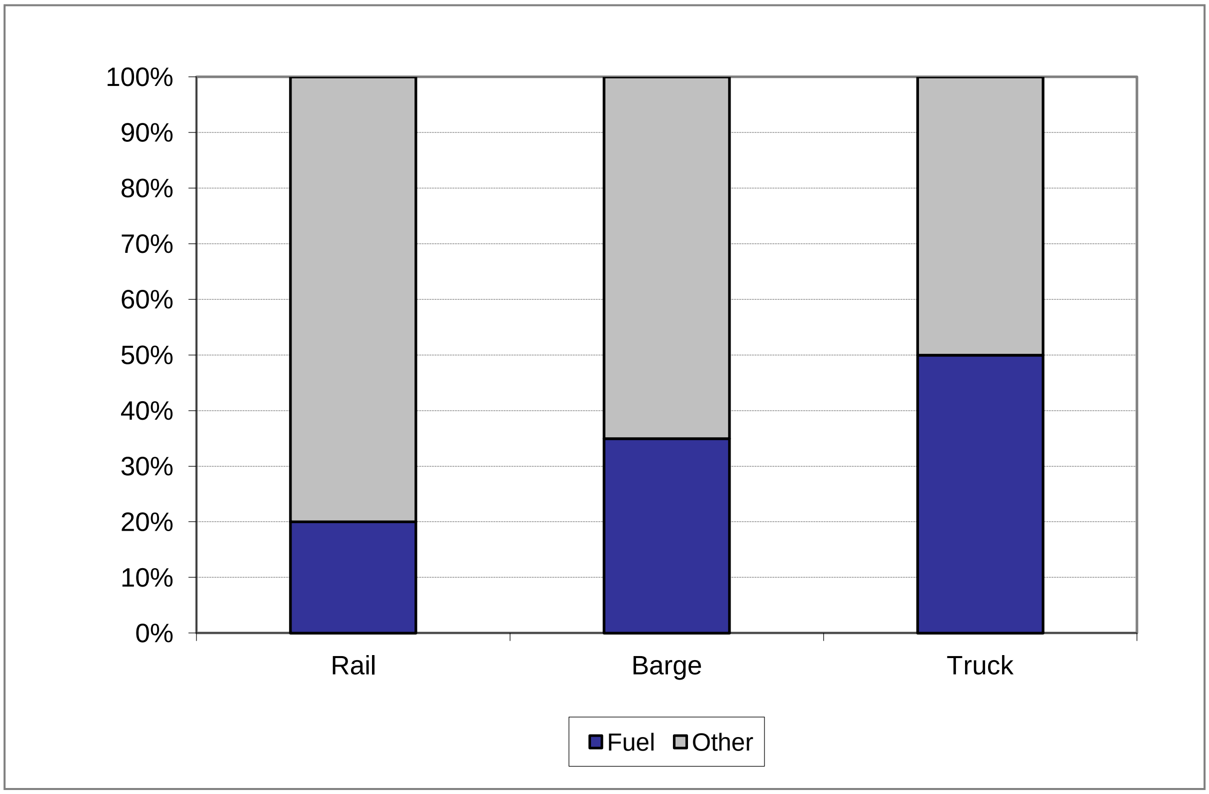
Figure 9-9.

Figure 9-9 Rail Cost Indices Performance
(2Q2008-4Q2011)



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 as shown in Figure 9-10 show that, at 2012 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)[86] forecast of long-term equilibrium prices for diesel fuel used in the transportation sector (see Table 9-16) shows expected prices ranging from about $3.83/gallon in 2012 to about $4.58/gallon in 2035 (2011 real dollars). This represents an annual real increase in diesel fuel prices of about 0.8%/year during 2012-2035. The coal transportation rate forecast for EPA Base Case v.5.13 assumes that this average rate of increase in diesel fuel prices will apply over EPA's entire forecast period (2016-2050).

Table 9-16 EIA AEO Diesel Fuel Forecast, 2012-2030 (2011 Real Dollars)

Year	Rate ($/gallon)
2012	3.83
2015	3.84
2020	4.06
2025	4.27
2030	4.48
2035	4.58
Annualized % Change, 2025-2035	0.8%

Source: EIA

[86] As noted at the beginning of this section, the coal transportation rate assumptions for EPA Base Case v5.13 were finalized in March 2012. At that time, the Annual Energy Outlook 2012 forecast was the latest available.

Iron Ore Prices

ABARES's[87] forecast of iron ore prices as depicted in Table 9-17 shows an expectation that iron ore prices will decline by about 22% in real terms for their 5-year forecast period (2012-2017) as a whole.

Table 9-17 ABARES Forecast of Iron Ore Prices

	2011 US$/metric tonne
ABARE Forecast of Average Contract Price for Australian Iron Ore Exports, 2012	137
ABARE Forecast for 2013	129
ABARE Forecast for 2014	125
ABARE Forecast for 2015	121
ABARE Forecast for 2016	115
ABARE Forecast for 2017	107
Total Percent Change (2012-2017)	-22%

Source: ABARES, Resources and Energy Quarterly, March 2012.

Labor Costs

As noted earlier, labor costs for the rail industry are expected to increase approximately 1% faster than overall inflation, on average over the forecast period. 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 expected to increase at approximately the same rate as overall inflation, on average over the forecast period.

Productivity Gains

The most recent data published by AAR (covering 2006-2010) shows that rail industry productivity increased at an annualized rate of approximately 0.8% 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. Although increased lock outages and the associated congestion on the inland waterway system as the river infrastructure ages may reduce the rate of future productivity gains in the barge industry, limited productivity gains are expected to occur, and these productivity gains are expected to be largely passed through to shippers since the barge industry is highly competitive.

Long-Term Escalation of Coal Transportation Rates

Based on the foregoing discussion, rail rates are expected to escalate at an average rate of 0.5% per year in real terms during 2013-2050. Over the same period, barge and lake vessel rates are expected to decline at an average rate of 0.2% per year, which reflects some pass-through of productivity gains in those highly competitive industries. Truck rates are expected to escalate at an average rate of 0.4%/year during 2013-2050, rates for conveyor transportation and transloading services are expected to be flat in real terms, on average over the forecast period.

The basis for these forecasts is summarized in

Table 9-18.

[87] ABARES (the Australian Bureau of Agricultural and Resource Economics and Sciences) 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 41% of total worldwide iron ore exports in 2011. See www.daff.gov.au/abares.

Mode	Component	Component Weighting	Real Escalation Before Productivity Adjustment (%/year)	Productivity Gains Passed Through to Shippers (%/year)	Real Escalation After Productivity Adjustment (%/year)
Rail	Fuel	20%	0.8%		
	Labor	35%	1.0%		
	Equipment	45%	0.0%		
	Total	**100%**	**0.5%**	**0.0%**	**0.5%**
Barge & Vessel	Fuel	35%	0.8%		
	Labor & Equip.	65%	0.0%		
	Total	**100%**	**0.3%**	**0.5%**	**-0.2%**
Truck	Fuel	50%	0.8%		
	Labor & Equip.	50%	0.0%		
	Total	**100%**	**0.4%**	**0.0%**	**0.4%**
Conveyor	**Total**		**0.0%**	**0.0%**	**0.0%**
Transloading Terminals	**Total**		**0.0%**	**0.0%**	**0.0%**

Table 9-18 Summary of Expected Escalation for Coal Transportation Rates, 2013-2050

9.3.10 Other Considerations

Estimated Construction Costs for Railcar Unloaders and Rail Spurs at Mine-Mouth Plants

In order to allow mine-mouth generating plants (i.e., coal-fired generating plants which take all of their current coal supply from a single nearby mine) to access additional types of coal, the costs of constructing facilities that would allow rail delivery of coal was estimated for almost all[88] of the mine-mouth generating plants with total capacity of 200 MW or more.

The facilities needed for rail delivery of coal to generating plants of this relatively large size were assumed to be: a) a rotary dump railcar unloader capable of handling unit train coal shipments, which is estimated to cost about $25 million installed (in 2011$). b) at least three miles of loop track, which would allow for one trainload of coal to be unloaded, and a second trainload of coal to simultaneously be parked on the plant site preparatory to unloading, and c) at least one mile of additional rail spur track to connect the trackage on the plant site with the nearest railroad main line. Since construction costs for rail trackage capable of handling coal trains is estimated at about $3 million per mile (in 2011$), the minimum investment required to construct the facilities needed for rail delivery of coal was estimated at $37 million. In some cases, the length of the rail spur required to reach the nearest main line (which was estimated on a plant-specific basis) is considerably longer than one mile. In cases where a rail spur longer than one mile was required to reach the main line, the cost of the additional trackage was estimated using the same construction cost of $3 million per mile (2011$) referenced earlier.

[88] The costs of rail coal delivery were not estimated for mine-mouth plants located in the Powder River Basin or Illinois Basin coal fields, since the coal reserves in these coal fields are among the largest, and among the cheapest to mine, anywhere in the United States.

The total cost of the facilities required for rail delivery of coal was converted to an annualized basis based on each plant's historical average coal burn from 2007-2011, and a capital recovery factor of 11.29%.

The cost of transporting additional types of coal to each mine-mouth generating plant was then calculated using the same methodology described earlier in this section, and added to the annualized cost for the rail delivery facilities, to arrive at an estimated "all-in" cost for delivering additional types of coal to the mine-mouth plants.

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

The coal supply curves used in EPA Base Case v.5.13 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 2012 was used in electricity generation – non-electricity 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, non-electric sector coal demand, and coal to liquids demand are based on EIA's AEO 2013.

In EPA Base Case v.5.13, coal exports, coal-serving residential, commercial and industrial demand, and coal to liquids demand are designed to correspond as closely as possible to the projections in AEO 2013 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.5.13 are identified that are contained in or overlap geographically with those in EIA Coal Market Module (CMM) supply regions and coal grades that are projected as serving exports and non-electric sector demand in AEO 2013. Next, coal for exports and non-electricity demand are constrained by CMM supply region and coal grade to meet the levels projected in AEO 2013. These levels are shown in Table 9-19.

Table 9-19 Coal Exports

Name	2016	2018	2020	2025	2030	2040-2050
Alaska/Washington - Subbituminous Low Sulfur	1.37	1.44	1.52	1.71	2.04	2.84
Central Appalachia - Bituminous Medium Sulfur	9.33	9.08	8.78	7.58	7.73	6.33
East Interior - Bituminous High Sulfur	16.54	18.23	20.10	25.65	32.74	45.51
Northern Appalachia - Bituminous High Sulfur	4.18	4.15	4.07	3.58	3.65	2.98
Northern Appalachia - Bituminous Medium Sulfur	0.44	0.32	0.23	0.10	0.10	0.10
Rocky Mountain - Bituminous Low Sulfur	3.21	3.54	3.90	3.92	4.73	4.45
Western Montana - Subbituminous Low Sulfur	8.22	9.07	4.85	12.83	16.49	27.28
Wyoming Southern PRB - Subbituminous Low Sulfur	0.42	0.31	6.21	0.10	0.10	0.10

Table 9-20 and Table 9-21. (Since the AEO 2013 time horizon extends to 2040 and EPA Base Case v.5.13 to 2050, the AEO projected levels for 2040 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.5.13 than in AEO 2013, the specific regions and coal grades that serve export and non-electric sector demand are not pre-specified but modeled.

Table 9-20 Residential, Commercial, and Industrial Demand

Name	2016	2018	2020	2025	2030	2040-2050
Alaska/Washington - Subbituminous Low Sulfur	0.59	0.59	0.59	0.59	0.59	0.60
Central Appalachia - Bituminous Low Sulfur	4.02	4.03	4.05	4.08	4.08	4.28
Central Appalachia - Bituminous Medium Sulfur	11.68	11.68	11.75	11.82	11.83	12.41

Name	2016	2018	2020	2025	2030	2040-2050
East Interior - Bituminous High Sulfur	7.04	7.00	7.00	6.97	6.89	7.04
East Interior - Bituminous Medium Sulfur	0.82	0.83	0.83	0.83	0.83	0.85
Northern Appalachia - Bituminous High Sulfur	1.63	1.62	1.62	1.62	1.61	1.66
Northern Appalachia - Bituminous Medium Sulfur	3.04	3.05	3.06	3.08	3.08	3.24
Rocky Mountain - Bituminous Low Sulfur	4.05	4.06	4.08	4.10	4.10	4.36
Southern Appalachia - Bituminous Low Sulfur	0.17	0.17	0.17	0.17	0.18	0.19
Southern Appalachia - Bituminous Medium Sulfur	1.13	1.13	1.14	1.15	1.16	1.24
Wyoming Southern PRB - Subbituminous Low Sulfur	2.58	2.56	2.56	2.55	2.52	2.58
Dakota Lignite - Lignite Medium Sulfur	6.37	6.34	6.34	6.31	6.25	6.38
Wyoming Northern PRB - Subbituminous Low Sulfur	5.04	5.04	5.06	5.09	5.09	5.31
West Interior - Bituminous High Sulfur	0.67	0.67	0.68	0.69	0.69	0.74
Arizona/New Mexico - Bituminous Low Sulfur	0.46	0.47	0.47	0.47	0.47	0.50
Arizona/New Mexico - Subbituminous Medium Sulfur	0.11	0.11	0.11	0.11	0.12	0.12
Western Wyoming - Subbituminous Low Sulfur	1.03	1.03	1.04	1.04	1.05	1.12
Western Wyoming - Subbituminous Medium Sulfur	1.12	1.13	1.13	1.14	1.15	1.24
Gulf Lignite - Lignite High Sulfur	0.84	0.85	0.85	0.87	0.87	0.93

Table 9-21 Coal to Liquids Demand

Name	2016	2018	2020	2025	2030	2040-2050
Rocky Mountain - Bituminous Low Sulfur	0	0	0	5.61	3.36	4.02
Wyoming Southern PRB - Subbituminous Low Sulfur	0	0	0	0.00	0.00	8.94
Wyoming Northern PRB - Subbituminous Low Sulfur	0	0	0	0.42	5.49	0.00
Western Montana - Subbituminous Low Sulfur	0	0	0	0.00	0.00	1.36

Imported coal is only available to 39 coal facilities which are eligible to receive imported coal. These facilities which may receive imported coal, along with the cost of transporting this coal to the demand regions, are in Excerpt from

Excerpt from Table 9-23. The total US imports of steam coal are limited to AEO 2013 projections as shown in Table 9-22**.**

Table 9-22 Coal Import Limits

	2016	2018	2020	2025	2030	2040-2050
Annual Coal Imports Cap (Million Short Tons)	1.50	0	0	3.60	3.78	34.28

Attachment 9-1 Mining Cost Estimation Methodology and Assumptions

Labor Costs

Productivity and labor cost rates are utilized to estimate the total labor cost associated with the mining operation. This excludes labor involved in any coal processing / preparation plant.

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.

Labor costs rates 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.

Surface Mining

The prime (raw coal) strip ratio and overburden volume is estimated on a year by year basis. Estimates are entered of the amount of overburden[89] moved each year, split by method to allow for different unit mining costs. The unit rate cost for each method excludes any drill and blast costs, and labor costs, as these are accounted for separately. Drill and blast costs are estimated as an average cost per volume of prime overburden. If applicable, dragline re-handle is estimated separately and a summation gives the total overburden moved.

The different overburden removal methods are:

- Dragline - the estimated volume of prime overburden moved
- Dragline re-handle - the estimated volume of any re-handled overburden
- Truck and shovel - including excavators.
- Other - examples would be dozer push, front end loader, or cast blasting. If overburden is moved by cast blasting the unit rate is taken to be zero as the cost is already included in the drill and blast estimate.

Surface mining costs also include the cost of coal mining estimated on a raw ton basis.

Underground Mining

Raw coal production is split by type into either continuous miner or longwall. Cost estimates can be input either on a unit rate or a fixed dollar amount, as the cost structure of underground mining generally has a large fixed component from year to year. Costs are divided into:

- Longwall
- Continuous miner
- Underground services

Underground services costs cover categories such as ventilation, conveyor transport, gas drainage, secondary roof support etc.

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

Mine Site Other

This covers any mine site costs that are outside the direct production process. Examples are ongoing rehabilitation/reclamation, security, community development costs.

Raw Haul

Costs for transporting raw coal from the mining location to the raw coal stockpile at the coal preparation plant or rail load out. A distance and a unit rate allows for an increasing cost over time if required.

Excerpt from Table 9-23 Coal Transportation Matrix in EPA Base Case v.5.13

This is a small excerpt of the data in Table 9-23. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

Link #	Plant Name	ORIS Plant Code	Coal Supply Region Code	Coal Supply Region Description	Total Cost (2012 Rate in 2011$/Ton)	Escalation/Year (2013-2025)	Escalation/Year (2026-2050)
1	Aurora Energy LLC Chena	79	AK	Alaska	$3.52	1.0050	1.0050
2	Eielson AFB Central Heat & Power Plant	50392	AK	Alaska	$4.32	1.0050	1.0050
3	Healy	6288	AK	Alaska	$1.00	1.0000	1.0000
4	Barry	3	CG	Colorado, Green River	$44.85	1.0039	1.0039
5	Barry	3	CR	Colorado, Raton	$42.85	1.0039	1.0039
6	Barry	3	CU	Colorado, Uinta	$48.85	1.0040	1.0040
7	Barry	3	IL	Illinois	$20.50	1.0031	1.0031
8	Barry	3	IN	Indiana	$24.00	1.0034	1.0034
9	Barry	3	KE	Kentucky East	$26.04	1.0031	1.0031
10	Barry	3	KW	Kentucky West	$19.78	1.0031	1.0031
11	Barry	3	PW	Pennsylvania, West	$25.77	1.0028	1.0028
12	Barry	3	WH	Wyoming, Powder River Basin (8800)	$43.13	1.0039	1.0039
13	Barry	3	WL	Wyoming, Powder River Basin (8400)	$42.90	1.0039	1.0039
14	Barry	3	WN	West Virginia, North	$23.04	1.0028	1.0028
15	Barry	3	WS	West Virginia, South	$27.45	1.0031	1.0031
16	Barry	3	I1	Imports-1 (Colombia)	$14.75	0.9995	0.9995
17	Charles R Lowman	56	CG	Colorado, Green River	$45.25	1.0039	1.0039
18	Charles R Lowman	56	CR	Colorado, Raton	$43.25	1.0039	1.0039
19	Charles R Lowman	56	CU	Colorado, Uinta	$49.25	1.0040	1.0040
20	Charles R Lowman	56	IL	Illinois	$20.90	1.0031	1.0031

Table 9-24 Coal Supply Curves in EPA Base Case v.5.13

This is a small excerpt of the data and graphs in Table 9-24. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/short ton)	Cost of Production (2011$/short ton)	Coal Production (Million short tons per annum)	End 2015 Coal Reserves (Million short tons)
2016	AL	BB	E1	25.5	47.51	0.09	0.19
2016	AL	BB	E2	25.5	75.16	0.06	0.30
2016	AL	BB	E3	25.5	81.84	1.18	8.37
2016	AL	BB	E4	25.5	88.23	0.14	1.39
2016	AL	BB	E5	25.5	96.45	0.47	4.51
2016	AL	BB	E6	25.5	101.89	0.07	0.69
2016	AL	BB	E7	25.5	103.68	0.10	0.94
2016	AL	BB	E8	25.5	110.04	0.08	0.75
2016	AL	BB	N1	25.5	115.74	0.12	500.00
2016	AL	BE	E1	24	35.96	0.21	0.36

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/short ton)	Cost of Production (2011$/short ton)	Coal Production (Million short tons per annum)	End 2015 Coal Reserves (Million short tons)
2016	AL	BE	E2	24	47.51	0.30	0.37
2016	AL	BE	E3	24	52.89	3.41	13.66
2016	AL	BE	E4	24	71.05	0.38	1.87
2016	AL	BE	E5	24	90.23	2.20	18.68
2016	AL	BE	E6	24	102.49	2.64	25.32
2016	AL	BE	E7	24	104.83	0.30	2.80
2016	AL	BE	E8	24	137.98	0.09	0.90
2016	AL	BE	N1	24	108.27	0.28	500.00