5. Emission Control Technologies

This chapter describes the emission control technology assumptions implemented in the EPA Platform v6 Post-IRA 2022 Reference Case (EPA Platform v6). EPA uses retrofit emission control cost models developed for EPA by the engineering firm Sargent & Lundy. EPA Platform v6 includes assumptions regarding control options for sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), carbon dioxide (CO_2), and hydrogen chloride (HCl). The options are listed in Table 5-1. They are available in EPA Platform v6 for meeting existing and potential federal, regional, and state emission limits. Besides the options shown in Table 5-1 and described in this chapter, EPA Platform v6 offers other compliance options for meeting emission limits. These include switching fuel, adjusting the level of dispatch, and retiring.

Table 5-1 Retrofit Emission Control Options in v6

SO_2 Control Technology Options	NO_x Control Technology Options	Mercury Control Technology Options	CO_2 Control Technology Options	HCl Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Activated Carbon Injection (ACI) System	CO_2 Capture and Sequestration	Limestone Forced Oxidation (LSFO) Scrubber
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	SO_2 and NO_x Control Technology Removal Co-benefits	Coal-to-Gas	Lime Spray Dryer (LSD) Scrubber
Dry Sorbent Injection (DSI)			Heat Rate Improvement	Dry Sorbent Injection (DSI)

Detailed reports and example calculation worksheets for Sargent & Lundy retrofit emission control cost models used by EPA are available in Attachment **5-1** through Attachment 5-9.

5.1 Sulfur Dioxide Control Technologies - Scrubbers

Two commercially available Flue Gas Desulfurization (FGD) scrubber technology options for removing the SO_2 produced by coal-fired power plants are offered in EPA Platform v6: Limestone Forced Oxidation (LSFO) — a wet FGD technology and Lime Spray Dryer (LSD) — a semi-dry FGD technology which employs a spray dryer absorber (SDA). In wet FGD systems the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In dry FGD systems the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency for SDA drops steadily for coals whose SO_2 content exceeds 3 lbs SO_2/MMBtu, the technology is therefore provided to only plants which have the option to burn coals with sulfur content no greater than 3 lbs SO_2/MMBtu. In EPA Platform v6 when a unit retrofits with an LSD SO_2 scrubber, it loses the option of burning certain high sulfur content coals (see Table 5-2).

The LSFO and LSD SO_2 emission control technologies are available to existing unscrubbed units. They are also available to existing scrubbed units with reported removal efficiencies of less than 50%. Such units are considered to have an injection technology and are classified as unscrubbed for modeling purposes in the NEEDS v6 database. The scrubber retrofit costs for these units are the same as those for regular unscrubbed units retrofitting with a scrubber.

Default SO_2 removal rates for wet and dry FGD were based on data reported in EIA 860 (2018). These default removal rates were the average of all SO_2 removal rates for a dry or wet FGD as reported in EIA 860 (2018) for the FGD installation year.

To reduce the incidence of implausibly high outlier removal rates, the following adjustment is made. Units for which reported EIA Form 860 (2018) SO_2 removal rates are higher than the average of the upper quartile of SO_2 removal rates across all scrubbed units are assigned the upper quartile average. The adjustment is not made, however, if a unit's reported removal rate was recently confirmed by utility comments. Furthermore, one upper quartile removal rate is calculated across all installation years and replaces any reported removal rate that exceeds it no matter the installation year.

Existing units not reporting FGD removal rates in EIA Form 860 (2018) are assigned the default SO_2 removal rate for a dry or wet FGD for that installation year.

The FGD removal efficiencies in South Carolina are based on efficiencies realized during the 2015-2018 period. In addition, the SO2 rate floor values for existing coal units with FGD's are calculated as follows.

- Dry FGD - minimum (0.08, minimum reported ETS SO_2 rate for the 2014-2018 period)

- Wet FGD - minimum (0.06, minimum reported ETS SO_2 rate for the 2014-2018 period)

As shown in Table 5-2, for FGD retrofits installed by the model, the assumed SO_2 removal rates will be 98% for wet FGD and 95% for dry FGD.

The procedures used to derive the cost of each scrubber type are discussed in detail in the following sections.

Table 5-2 Retrofit SO_2 Emission Control Performance Assumptions in v6

Performance Assumptions	Limestone Forced Oxidation (LSFO)	Lime Spray Dryer (LSD)
Percent Removal*	98% with a floor of 0.06 lbs/MMBtu	95% with a floor of 0.08 lbs/MMBtu
Capacity Penalty	Calculated based on characteristics of the unit: See Table 5-3	Calculated based on characteristics of the unit: See Table 5-3
Heat Rate Penalty		
Cost (2019$)		
Applicability	Units ≥ 25 MW	Units ≥ 25 MW
Sulfur Content Applicability		Coals ≤ 3 lbs SO_2/MMBtu
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, SE, LD, LE, LG, LH, PK, and WC	BA, BB, BD, BE, SA, SB, SD, SE, LD, and LE

* If the SO_2 permit rate of the unit is lower than the floor rate, the SO_2 permit rate is used as the floor rate.

Potential (new) coal-fired units built by IPM are also assumed to be constructed with a wet scrubber achieving a removal efficiency of 98%. Further, the costs of potential new coal units include the cost of scrubbers.

5.1.1 Methodology for Obtaining SO_2 Controls Costs

Sargent & Lundy's updated performance/cost models for wet and dry SO_2 scrubbers are implemented in EPA Platform v6 to develop the capital, fixed O&M (FOM), and variable O&M (VOM) components of cost. For details of Sargent & Lundy Wet FGD and SDA FGD cost models, see Attachment 5-1 and Attachment 5-2.

<u>Capacity and Heat Rate Penalties</u>: In IPM the amount of electrical power required to operate a retrofit emission control device is represented through a reduction in the amount of electricity available for sale to the grid. For example, if 1.6% of a unit's electrical generation is needed to operate a scrubber, the unit's capacity is reduced by 1.6%. The reduction in the unit's capacity is called the capacity penalty. At the same time, to capture the total fuel used in generation both for sale to the grid and for internal load (i.e., for operating the control device), the unit's heat rate is scaled up such that a comparable reduction (1.6%

in the example) in the new higher heat rate yields the original heat rate.[50] The factor used to scale up the original heat rate is called the heat rate penalty. It is a modeling procedure only and does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency).[51] In EPA Platform v6, specific LSFO and LSD heat rate and capacity penalties are calculated for each installation based on equations from the Sargent & Lundy models that consider the rank of coal burned, its uncontrolled SO_2 rate, and the heat rate of the model plant.

Table 5-3 presents the LSFO and LSD capital, fixed O&M, and variable O&M costs as well as capacity and heat rate penalties for representative capacities and heat rates.

5.1.2 SO_2 Controls for Units with Capacities from 25 MW to 100 MW (25 MW ≤ capacity < 100 MW)

In EPA Platform v6, coal units with capacities between 25 MW and 100 MW are offered the same SO_2 control options as larger units. However, for modeling purposes, the costs of controls for these units are assumed to be equivalent to that of a 50 MW for Dry FGD and 100 MW for Wet FGD. These assumptions are based on several considerations. First, to achieve economies of scale, several units within this size range are likely to be ducted to share a single common control, so the minimum capacity cost equivalency assumption, though generic, would be technically plausible. Second, single units within this size range that are not grouped to achieve economies of scale are likely to switch to a lower sulfur coal, repower or convert to natural gas firing, use dry sorbent injection, and/or reduce operating hours.

Illustrative scrubber costs for 25-100 MW coal units with a range of heat rates can be found by referring to the LSFO 100 MW and LSD 100MW "Capital Costs ($/kW)" and "Fixed O&M" columns in Table 5-3. The Variable O&M cost component, which applies to units regardless of size, can be found in the fifth column in this table.

[50] Mathematically, the relationship of the heat rate and capacity penalties (both expressed as positive percentage values) can be represented as follows:

$$\text{Heat Rate Penalty} = \left(\frac{1}{\left(1 - \frac{\text{Capacity Penalty}}{100}\right)} - 1 \right) \times 100$$

[51] The NEEDS heat rate is an unmodified, original heat rate to which this retrofit-based heat rate penalty procedure is applied. The procedure is limited to units at which IPM adds a retrofit in the model.

Table 5-3 Illustrative Scrubber Costs (2019$) for Representative Capacities and Heat Rates in v6

Scrubber Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
LSFO Minimum Cutoff: ≥ 25 MW	9,000	-1.60	1.63	2.42	949	26.3	689	12.5	594	9.3	539	8.6	486	7.1
Maximum Cutoff: None	10,000	-1.78	1.82	2.67	994	26.7	722	12.9	622	9.6	564	8.9	509	7.4
	11,000	-1.96	2.00	2.92	1,036	27.2	752	13.2	649	9.9	588	9.1	531	7.6
LSD Minimum Cutoff: ≥ 25 MW	9,000	-1.18	1.20	2.79	801	19.2	587	9.6	507	7.3	455	6.2	455	5.7
Maximum Cutoff: None	10,000	-1.32	1.33	3.11	839	19.6	614	9.9	531	7.6	477	6.4	477	5.9
	11,000	-1.45	1.47	3.42	875	19.9	640	10.2	554	7.8	497	6.6	497	6.1

Note 1: The above cost estimates assume a boiler burning 3 lb/MMBtu SO_2 Content Bituminous Coal for LSFO and 2 lb/MMBtu SO_2 Content Bituminous Coal for LSD.

Note 2: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the Sargent & Lundy cost models. For modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.

5.2 Nitrogen Oxides Control Technology

There are two main categories of NO_x reduction technologies: combustion and post-combustion controls. Combustion controls reduce NO_x emissions during the combustion process by regulating flame characteristics such as temperature and fuel-air mixing. Post-combustion controls operate downstream of the combustion process and remove NO_x emissions from the flue gas. All the technologies included in EPA Platform v6 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

EPA Platform v6 does not model combustion control upgrades as a retrofit option. The decision was based on two considerations, the relatively low cost of combustion controls compared with that of post combustion NO_x controls and the possible impact on model size. EPA identified units in NEEDS that have not employed state-of-the-art combustion controls. EPA then estimated the NO_x rates for such units based on an analysis of historical rates of units with state-of-the-art NO_x combustion controls. Emission rates provided by state-of-the-art combustion controls are presented in Attachment 3-2.

5.2.2 Post-combustion NO_x Controls

EPA Platform v6 provides two post-combustion retrofit NO_x control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Oil/gas steam units, on the other hand, are provided with only SCR retrofits. NO_x reduction in a SCR system takes place by injecting ammonia (NH_3) vapor into the flue gas stream where the NO_x is reduced to nitrogen (N_2) and water (H_2O) abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten. As its name implies, SNCR operates without a catalyst. In a SNCR system, a nitrogenous reducing agent (reagent), typically urea or ammonia, is injected into, and mixed with, hot flue gas where it reacts with the NO_x in the gas stream reducing it to nitrogen gas and water vapor. Due to the presence of a catalyst, SCR can achieve greater NO_x reductions than SNCR. However, SCR costs are higher than SNCR costs.

Table 5-4 summarizes the performance and applicability assumptions for each post-combustion NO_x control technology and provides a cross-reference to information on cost assumptions.

Table 5-4 Retrofit NO_x Emission Control Performance Assumptions in v6

Control Performance Assumptions	**Selective Catalytic Reduction (SCR)**		**Selective Non-Catalytic Reduction (SNCR)**
Unit Type	Coal	Oil/Gas	Coal
Output Rate	0.05 lb/MMBtu	0.03 lb/MMBtu	--
Percent Removal	--	--	Pulverized Coal: 25% (25-200 MW), 20% (200-400 MW), 15% (>400 MW) Fluidized Bed: 50%
Rate Floor	--	--	Pulverized Coal: 0.1 lb/MMBtu Fluidized Bed: 0.08 lb/MMBtu
Size Applicability	Units ≥ 25 MW	Units ≥ 25 MW	Units ≥ 25 MW
Costs (2019$)	See Table 5-5	See Table 5-6	See Table 5-5

5.2.3 Methodology for Obtaining SCR and SNCR Costs for Coal Steam Units

Sargent & Lundy SCR and SNCR cost models are implemented to develop the capital, fixed O&M, and variable O&M costs. For details of Sargent & Lundy SCR and SNCR cost models, see Attachment 5-3, Attachment 5-4, Attachment 5-5, and Attachment 5-6.

In the Sargent & Lundy's cost models for SNCR, the NO_x removal efficiency varies by unit size and burner type as summarized in Table 5-4. Additionally, the capital, fixed, and variable operating and maintenance costs of SNCR on circulating fluidized bed (CFB) units are distinguished from the corresponding costs for other boiler types (e.g., cyclone and wall fired). -An air heater modification cost applies for plants that burn bituminous coal whose SO_2 content is 3 lbs/MMBtu or greater.

Table 5-5 presents the SCR and SNCR capital, fixed O&M, and variable O&M costs as well as capacity and heat rate penalties for coal steam units of representative capacities and heat rates.

Table 5-5 Illustrative Post Combustion NOx Control Costs (2019$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in v6

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
SCR	9,000	-0.54	0.54	1.34	430	2.12	352	0.94	326	0.81	311	0.74	298	0.69
Minimum Cutoff: ≥ 25 MW	10,000	-0.56	0.56	1.45	468	2.25	384	1.01	357	0.87	341	0.80	327	0.75
Maximum Cutoff: None	11,000	-0.58	0.59	1.56	505	2.38	417	1.08	388	0.94	371	0.87	355	0.81
SNCR - Tangential, 25% Removal Efficiency	9,000			1.12	59	0.52	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Minimum Cutoff: ≥ 25 MW	10,000	-0.05	0.78	1.25	60	0.54	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Maximum Cutoff: 200 MW	11,000			1.37	62	0.55	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SNCR - Tangential, 20% Removal Efficiency	9,000			0.90	N/A	N/A	31	0.28	N/A	N/A	N/A	N/A	N/A	N/A
Minimum Cutoff: ≥ 200 MW	10,000	-0.05	0.63	1.00	N/A	N/A	32	0.28	N/A	N/A	N/A	N/A	N/A	N/A
Maximum Cutoff: 400 MW	11,000			1.10	N/A	N/A	33	0.29	N/A	N/A	N/A	N/A	N/A	N/A
SNCR - Tangential, 15% Removal Efficiency	9,000			0.67	N/A	N/A	N/A	N/A	23	0.21	19	0.17	16	0.14
Minimum Cutoff: ≥ 400 MW	10,000	-0.05	0.49	0.75	N/A	N/A	N/A	N/A	23	0.21	19	0.17	16	0.14
Maximum Cutoff: None	11,000			0.82	N/A	N/A	N/A	N/A	24	0.22	20	0.17	16	0.14
SNCR - Fluidized Bed	9,000			2.26	47	0.41	25	0.23	19	0.17	16	0.14	13	0.12
Minimum Cutoff: ≥ 25 MW	10,000	-0.05	1.51	2.52	48	0.43	26	0.23	20	0.17	16	0.14	13	0.12
Maximum Cutoff: None	11,000			2.77	49	0.44	27	0.24	20	0.17	17	0.14	14	0.12

Note 1: Assumes Bituminous Coal, NO_x rate: 0.5 lb/MMBtu, and SO_2 rate: 2.0 lb/MMBtu.

Note 2: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the Sargent & Lundy cost models. For modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.

Note 3: Heat rate penalty includes the effect of capacity penalty.

5.2.4 Methodology for Obtaining SCR Costs for Oil/Gas Steam Units

The cost calculations for SCR described in section 5.2.3 apply to coal units. Table 5-6 presents the SCR and SNCR capital, fixed O&M, and variable O&M costs as well as capacity and heat rate penalties for oil/gas steam units of representative capacities and heat rates.

Table 5-6 Post-Combustion NOx Controls Costs (2019$) for Oil/Gas Steam for Representative Sizes and Heat Rates under the Assumptions in v6

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
SCR Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Natural Gas NO_x rate: 0.3 lb/MMBtu	9,000	-0.27	0.27	0.64	181	1.25	137	0.49	124	0.38	117	0.33	110	0.29
	10,000	-0.28	0.28	0.71	195	1.30	149	0.52	135	0.41	127	0.35	120	0.31
	11,000	-0.29	0.29	0.78	209	1.35	161	0.54	146	0.43	138	0.38	131	0.34
SCR Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Oil NO_x rate: 0.3 lb/MMBtu	9,000	-0.27	0.28	0.65	188	1.27	143	0.51	130	0.40	122	0.34	116	0.30
	10,000	-0.29	0.29	0.72	203	1.32	156	0.53	141	0.42	134	0.37	126	0.33
	11,000	-0.30	0.30	0.79	217	1.38	168	0.56	153	0.44	145	0.39	137	0.35

5.3 Biomass Co-firing

Biomass co-firing is provided as an option for those coal-fired units in EPA Platform v6 that per EIA Form 923 had co-fired biomass during the 2015-2019 period. Table 5-7 lists the units provided with the co-firing option and the limit on share of the biomass co-firing. The remaining coal power plants are not provided with this choice as logistics and boiler engineering considerations place limits on the extent of biomass that can be fired. The logistical considerations arise primarily because biomass is only economic to transport a limited distance from where it is grown due to its relatively low energy density. In addition, the extent of storage that can be devoted at a power plant to such a fuel is another limiting factor. Boiler efficiency and other engineering considerations, largely driven by the relatively higher moisture content and lower heat content of biomass compared to fossil fuel, also plays a role in limiting the potential adoption of co-firing.

Table 5-7 Coal Units with Biomass Co-firing Option in v6

Plant Name	Unit ID	Biomass Co-Firing Share Limit (%)[52]
Virginia City Hybrid Energy Center	1	16.3
University of Iowa Main Power Plant	BLR11	45.3
University of Iowa Main Power Plant	BLR10	97.6
Northampton Generating Company LP	BLR1	0.7
TES Filer City Station	2	4.4
TES Filer City Station	1	4.4
Pixelle Specialty Solutions LLC - Spring Grove Facility	5PB036	32.9
Manitowoc	9	18.2
Schiller	6	2.0
Schiller	4	1.9
Hibbing	4	99.7

5.4 Mercury Control Technologies

For any power plant, mercury emissions depend on the mercury content of the fuel used, the combustion and physical characteristics of the unit, and the emission control technologies deployed. In the absence of activated carbon injection (ACI), mercury emission reductions below the mercury content of the fuel are strictly due to characteristics of the combustion process and incidental removal resulting from other pollution control technologies, e.g., the SO_2, NO_x, and particulate matter controls. The following discussion is divided into three parts. Sections 5.4.1 and 5.4.2 explain the two factors that determine mercury emissions that result from unit configurations lacking ACI. Section 5.4.1 discusses how mercury content of fuel is modeled. Section 5.4.2 looks at the procedure to capture the mercury reductions resulting from different unit and (non-mercury) control configurations. Section 5.4.3 explains the mercury emission control options that are available. Each section indicates the data sources and methodology used.

5.4.1 Mercury Content of Fuels

Coal

Assumptions pertaining to the mercury content of coal (and the majority of emission modification factors discussed below in Section 5.4.2) are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR).[53] A two-year effort

[52] In EPA Platform v6, the limit on biomass co-firing is expressed as the percentage of the facility (ORIS code) level fuel input that is produced from biomass.

[53] Data from the ICR can be found at http://www.epa.gov/ttn/atw/combust/utiltox/mercury.html. In 2009, EPA collected some additional information regarding mercury through the Collection Effort for New and Existing Coal- and

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 [MWe]), 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.

The ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content and other characteristics of coal burned at coal-fired utility units greater than 25 MW. To make this data usable, these data points were first grouped by IPM coal types and IPM coal supply regions. IPM coal types divide bituminous, subbituminous, and lignite coal into different grades based on sulfur content.

Oil, natural gas, and waste fuels

Assumptions pertaining to the mercury content for oil, gas, and waste fuels are based on data derived from previous EPA analysis of mercury emissions from power plants.[54] Table 5-8 provides a summary of the assumptions on the mercury content for oil, gas, and waste fuels.

Table 5-8 Mercury Concentration Assumptions for Non-Coal Fuels in v6

Fuel Type	Mercury Concentration (lbs/TBtu)
Oil	0.48
Natural Gas	0.00 [a]
Petroleum Coke	2.66
Biomass	0.57
Municipal Solid Waste	71.85
Geothermal Resource	2.97 - 3.7

Note:

[a] The values appearing in this table are rounded to two decimal places. The zero-value shown for natural gas is based on an EPA study that found a mercury content of 0.000138 lbs/TBtu. Values for geothermal resources represent a range.

5.4.2 Mercury Emission Modification Factors

Emission Modification Factors (EMFs) represent the mercury reductions attributable to the specific burner type and configuration of SO_2, NO_x, and particulate matter control devices at an electric generating unit. An EMF is the ratio of outlet mercury concentration to inlet mercury concentration, and depends on the unit's burner type, particulate control device, post-combustion NO_x control and SO_2 scrubber control. In other words, the mercury reduction achieved (relative to the inlet) during combustion and flue-gas treatment process is (1-EMF), such that the lower the EMF, the greater the mercury reduction. If the EMF is 0.25, then 25% of the inlet mercury concentration is emitted as outlet mercury concentration, and therefore the unit has achieved a 75% reduction in mercury that would otherwise be emitted without the properties influencing the EMF. The EMF varies by the type of coal (i.e., bituminous, subbituminous, and lignite) used during the combustion process.

Deriving EMFs involves obtaining mercury inlet data by coal sampling and mercury emission data by stack testing at a representative set of coal units. As noted, EPA's EMFs were initially based on 1999 mercury ICR emission test data. More recent testing conducted by the EPA, DOE, and industry

Oil-Fired Electricity Utility Steam Generating Units (EPA ICR No.2362.01 (OMB Control Number 2060-0631), however the information collected was not similarly comprehensive and was thus not used to update mercury assumptions in EPA Platform v6.

[54] Analysis of Emission Reduction Options for the Electric Power Industry, Office of Air and Radiation, U.S. EPA, March 1999.

participants[55] has provided a better understanding of mercury emissions from electric generating units and mercury capture in pollution control devices. Overall, the 1999 ICR data revealed higher levels of mercury capture for bituminous coal-fired plants than for subbituminous and lignite coal-fired plants, and significant capture of ionic Hg in wet-FGD scrubbers. Additional mercury testing indicates that for bituminous coals, SCR systems can convert elemental Hg into ionic Hg and thus allow easier capture in a downstream wet-FGD scrubber. This understanding of mercury capture with SCRs is incorporated in EPA Platform v6 mercury EMFs for unit configurations with SCR and wet scrubbers.

Table 5-9 provides a summary of EMFs used in EPA Platform v6. Table 5-10 provides definitions of acronyms for existing controls that appear in Table 5-9. Table 5-11 provides a key to the burner type designations appearing in Table 5-9.

Table 5-9 Mercury Emission Modification Factors Used in v6

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF*	Lignite EMF
FBC	Cold Side ESP	No SCR	None	0.65	0.1	0.62
FBC	Cold Side ESP	No SCR	Dry FGD	0.64	0.1	1
FBC	Cold Side ESP + FF	No SCR	None	0.05	0.1	0.43
FBC	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.1	1
FBC	Fabric Filter	No SCR	None	0.05	0.1	0.43
FBC	Fabric Filter	No SCR	Dry FGD	0.05	0.1	0.43
FBC	Hot Side ESP + FGC	No SCR	None	1	0.1	1
FBC	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.1	1
FBC	No Control	No SCR	None	1	0.1	1
Non FBC	Cold Side ESP	SCR	None	0.64	0.1	1
Non FBC	Cold Side ESP	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Cold Side ESP	SCR	Dry FGD	0.64	0.1	1
Non FBC	Cold Side ESP	No SCR	None	0.64	0.1	1
Non FBC	Cold Side ESP	No SCR	Wet FGD	0.05	0.1	0.56
Non FBC	Cold Side ESP	No SCR	Dry FGD	0.64	0.1	1
Non FBC	Cold Side ESP + FF	SCR	None	0.2	0.1	1
Non FBC	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Cold Side ESP + FF	SCR	Dry FGD	0.05	0.1	1
Non FBC	Cold Side ESP + FF	No SCR	None	0.2	0.1	1
Non FBC	Cold Side ESP + FF	No SCR	Wet FGD	0.05	0.1	0.56
Non FBC	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.1	1
Non FBC	Cold Side ESP + FGC	SCR	None	0.64	0.1	1
Non FBC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.1	1
Non FBC	Cold Side ESP + FGC	No SCR	None	0.64	0.1	1
Non FBC	Cold Side ESP + FGC	No SCR	Wet FGD	0.05	0.1	0.56
Non FBC	Cold Side ESP + FGC	No SCR	Dry FGD	0.64	0.1	1
Non FBC	Cold Side ESP + FGC + FF	SCR	None	0.2	0.1	1
Non FBC	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.1	1
Non FBC	Cold Side ESP + FGC + FF	No SCR	None	0.2	0.1	1
Non FBC	Cold Side ESP + FGC + FF	No SCR	Wet FGD	0.05	0.1	0.56

[55] For a detailed summary of emissions test data see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, February 2005. The report can be found at https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=219113.

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF*	Lignite EMF
Non FBC	Cold Side ESP + FGC + FF	No SCR	Dry FGD	0.05	0.1	1
Non FBC	Fabric Filter	SCR	None	0.11	0.1	1
Non FBC	Fabric Filter	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Fabric Filter	SCR	Dry FGD	0.05	0.1	1
Non FBC	Fabric Filter	No SCR	None	0.11	0.1	1
Non FBC	Fabric Filter	No SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Fabric Filter	No SCR	Dry FGD	0.05	0.1	1
Non FBC	Hot Side ESP	SCR	None	0.9	0.1	1
Non FBC	Hot Side ESP	SCR	Wet FGD	0.1	0.1	1
Non FBC	Hot Side ESP	SCR	Dry FGD	0.6	0.1	1
Non FBC	Hot Side ESP	No SCR	None	0.9	0.1	1
Non FBC	Hot Side ESP	No SCR	Wet FGD	0.05	0.1	1
Non FBC	Hot Side ESP	No SCR	Dry FGD	0.6	0.1	1
Non FBC	Hot Side ESP + FF	SCR	None	0.11	0.1	1
Non FBC	Hot Side ESP + FF	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Hot Side ESP + FF	SCR	Dry FGD	0.05	0.1	1
Non FBC	Hot Side ESP + FF	No SCR	None	0.11	0.1	1
Non FBC	Hot Side ESP + FF	No SCR	Wet FGD	0.03	0.1	0.56
Non FBC	Hot Side ESP + FF	No SCR	Dry FGD	0.05	0.1	1
Non FBC	Hot Side ESP + FGC	SCR	None	0.9	0.1	1
Non FBC	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.1	1
Non FBC	Hot Side ESP + FGC	SCR	Dry FGD	0.6	0.1	1
Non FBC	Hot Side ESP + FGC	No SCR	None	0.9	0.1	1
Non FBC	Hot Side ESP + FGC	No SCR	Wet FGD	0.05	0.1	1
Non FBC	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.1	1
Non FBC	Hot Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.1	1
Non FBC	Hot Side ESP + FGC + FF	No SCR	None	0.11	0.1	1
Non FBC	Hot Side ESP + FGC + FF	No SCR	Dry FGD	0.05	0.1	1
Non FBC	No Control	SCR	None	1	0.1	1
Non FBC	No Control	SCR	Wet FGD	0.1	0.1	1
Non FBC	No Control	SCR	Dry FGD	0.6	0.1	1
Non FBC	No Control	No SCR	None	1	0.1	1
Non FBC	No Control	No SCR	Wet FGD	0.58	0.1	1
Non FBC	No Control	No SCR	Dry FGD	0.6	0.1	1
Non FBC	PM Scrubber	SCR	None	0.9	0.1	1
Non FBC	PM Scrubber	SCR	Wet FGD	0.1	0.1	1

Note: 2017 annual emissions data suggests that, with subbituminous coal, many configurations are now achieving at least 90% removal of mercury. This table was updated from previous versions to reflect this recent observation. For 2017 emissions data, see: https://ampd.epa.gov.

Table 5-10 Definition of Acronyms for Existing Controls

Acronym	Description
ESP	Electrostatic Precipitator - Cold Side
HESP	Electrostatic Precipitator - Hot Side
ESP/O	Electrostatic Precipitator - Other
FF	Fabric Filter
FGD	Flue Gas Desulfurization - Wet
DS	Flue Gas Desulfurization - Dry
SCR	Selective Catalytic Reduction
PMSCRUB	Particulate Matter Scrubber

Table 5-11 Key to Burner Type Designations in Table 5-9

"PC" refers to conventional pulverized coal boilers. Typical configurations include wall-fired and tangentially fired boilers (also called T-fired boilers). In wall-fired boilers the burner's coal and air nozzles are mounted on a single wall or opposing walls. In tangentially fired boilers the burner's coal and air nozzles are mounted in each corner of the boiler.
"Cyclone" refers to cyclone boilers where air and crushed coal are injected tangentially into the boiler through a "cyclone burner" and "cyclone barrel" which create a swirling motion allowing smaller coal particles to be burned in suspension and larger coal particles to be captured on the cyclone barrel wall where they are burned in molten slag.
"Stoker" refers to stoker boilers where lump coal is fed continuously onto a moving grate or chain, which moves the coal into the combustion zone in which air is drawn through the grate and ignition takes place. The carbon gradually burns off, leaving ash which drops off at the end into a receptacle, from which it is removed for disposal.
"FBC" refers to "fluidized bed combustion" where solid fuels are suspended on upward-blowing jets of air, resulting in a turbulent mixing of gas and solids and a tumbling action which provides especially effective chemical reactions and heat transfer during the combustion process.
"Other" refers to miscellaneous burner types including cell burners and arch, roof, and vertically-fired burner configurations.

5.4.3 Mercury Control Capabilities

EPA Platform v6 offers two options for mercury pollution control: (1) combinations of SO_2, NO_x, and particulate controls which deliver mercury reductions as a co-benefit; and (2) Activated Carbon Injection (ACI), a retrofit option specifically designed for mercury control. The options are discussed below.

Mercury Control through SO_2 and NO_X Retrofits

Units that install SO_2, NO_x, and particulate controls reduce mercury emissions as a byproduct of these retrofits. Section 5.4.2 described how EMFs are used to capture mercury emissions depending on the rank of coal burned, the generating unit's combustion characteristics, and the specific configuration of SO_2, NO_x, and particulate controls (i.e., hot and cold-side electrostatic precipitators (ESPs), fabric filters (also called "baghouses"), and particulate matter (PM) scrubbers).

Activated Carbon Injection (ACI)

The technology used for mercury control in EPA Platform v6 is Activated Carbon Injection (ACI) downstream of the combustion process in coal fired units. Sargent & Lundy's updated cost and performance assumptions for ACI are used (and are described further below).

Three alternative ACI options are represented as capable of providing 90% mercury removal for all possible configurations of boiler, emission controls, and coal types used in the U.S. electric power sector. The three ACI options differ, based on whether they are used in conjunction with an electrostatic precipitator (ESP) or a fabric filter (also called a baghouse). The three ACI options are:

- ACI with Existing ESP
- ACI with Existing Baghouse
- ACI with an Additional Baghouse (also referred to as Toxecon)

In the third option listed above the additional baghouse is installed downstream of the pre-existing particulate matter device and the activated carbon is injected after the existing controls. This configuration allows the fly ash to be removed before it is contaminated by the mercury.

For modeling purposes, EPA assumes that all three configurations use brominated ACI, where a small amount of bromine is chemically bonded to the powdered carbon, which is injected into the flue gas stream. EPA recognizes that amended silicates and possibly other non-carbon, non-brominated substances are in development and may become available as alternatives to brominated carbon as a mercury sorbent.

The applicable ACI option depends on the coal type burned, its SO_2 content, the boiler and particulate control type, and in some instances consideration of whether an SO_2 scrubber (FGD) system and SCR NO_x post-combustion control are present. Table 5-12 shows the ACI assignment scheme used to achieve 90% mercury removal. EPA Platform v6 does not explicitly model ACI retrofit options.

Table 5-12 Assignment Scheme for Mercury Emissions Control Using Activated Carbon Injection in v6

Air pollution controls				Bituminous Coal			Subbituminous Coal			Lignite Coal		
Burner Type	Particulate Control Type	SCR System	FGD System	ACI Required?	Toxecon Required?	Sorbent Inj Rate (lb/million acfm)	ACI Required?	Toxecon Required?	Sorbent Inj Rate (lb/million acfm)	ACI Required?	Toxecon Required?	Sorbent Inj Rate (lb/million acfm)
FBC	Cold Side ESP + Fabric Filter without FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
FBC	Cold Side ESP without FGC	--	--	Yes	No	5	Yes	No	5	Yes	No	5
FBC	Fabric Filter	--	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
FBC	Fabric Filter	--	--	Yes	No	2	Yes	No	2	Yes	No	2
FBC	Hot Side ESP with FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	--	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	SCR	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	--	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	SCR	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP with FGC	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP without FGC	--	--	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	--	Wet FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	SCR	--	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	SCR	Dry FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	SCR	Wet FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Fabric Filter	--	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	SCR	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	--	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	--	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	SCR	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2

Air pollution controls				Bituminous Coal			Subbituminous Coal			Lignite Coal		
Burner Type	**Particulate Control Type**	**SCR System**	**FGD System**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acfm)**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acfm)**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acfm)**
Non-FBC	Hot Side ESP + Fabric Filter without FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP with FGC	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2

Note: In the table above "Toxecon" refers to the option described as "ACI System with an Additional Baghouse" and "ACI + Full Baghouse with a Sorbent Injection (Inj) Rate of 2 lbs/million acfm" elsewhere in this chapter.

5.4.4 Methodology for Obtaining ACI Control Costs

The ACI model developed by Sargent & Lundy in 2017 assumes that the carbon feed rate dictates the size of the equipment and resulting costs. The feed rate in turn is a function of the required removal (in this case 90%) and the type of particulate control device. The model assumes a carbon feed rate of 5 pounds of carbon injected for every 1,000,000 actual cubic feet per minute (acfm) of flue gas would provide the stipulated 90% mercury removal rate for units shown in Table 5-13 as qualifying for ACI systems with existing ESP. For generating units with fabric filters a lower injection rate of 2 pound per million acfm is required. Alternative sets of costs were developed for each of the three ACI options: ACI systems for units with existing ESPs, ACI for units with existing fabric filters (baghouses), and the combined cost of ACI plus an additional baghouse for units that either have no existing particulate control or that require ACI plus a baghouse in addition to their existing particulate control. There are various reasons that a combined ACI plus additional baghouse would be required. These include situations where the existing ESP cannot handle the additional particulate load associated with the ACI or where SO_3 injection is currently in use to condition the flue gas for the ESP. Another cause for combined ACI and baghouse is use of PRB coal whose combustion produces mostly elemental mercury, not ionic mercury, due to this coal's low chlorine content.

For the combined ACI and fabric filter option a full-size baghouse with an air-to-cloth (A/C) ratio of 4.0 is assumed, as opposed to a polishing baghouse with a 6.0 A/C ratio.[56]

Table 5-13 presents the capital, fixed O&M, and variable O&M costs as well as the capacity and heat rate penalties for the three ACI options represented in EPA Platform v6. For each ACI option, values are shown for an illustrative set of generating units with a representative range of capacities and heat rates. For details of Sargent & Lundy ACI cost model, see Attachment 5-8.

5.5 Hydrogen Chloride (HCl) Control Technologies

The following sub-sections describe how HCl emissions from coal are represented, the emission control technologies available for HCl removal, and the cost and performance characteristics of these technologies in EPA Platform v6.

5.5.1 Chlorine Content of Fuels

HCl emissions from the power sector result from the chlorine content of the coal that is combusted by electric generating units. Data on chlorine content of coals had been collected as part of EPA's 1999 "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR 1999) described above in section 5.4.1. This data is incorporated into the model to provide the capability for EPA Platform v6 to project HCl emissions. The procedures used for this are presented below.

Western subbituminous coal (such as that mined in the Powder River Basin), and lignite coal contain natural alkalinity in the form of non-glassy calcium oxide (CaO) and other alkaline and alkaline earth oxides. This fly ash (classified as 'Class C' fly ash) has a natural pH of 9 and higher and the natural alkalinity can effectively neutralize much of the HCl in the flue gas stream prior to the primary control device.

[56] The air-to-cloth (A/C) ratio is the volumetric flow, (typically expressed in Actual Cubic Feet per Minute, ACFM) of flue gas entering the baghouse divided by the areas (typically in square feet) of fabric filter cloth in the baghouse. The lower the A/C ratio, e.g., A/C = 4.0 compared to A/C = 6.0, the greater area of the cloth required and the higher the cost for a given volumetric flow.

Table 5-13 Illustrative Activated Carbon Injection (ACI) Costs (2019$) for Representative Sizes and Heat Rates under the Assumptions in v6

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M cost (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
ACI System with an Existing ESP ACI with a Sorbent Injection Rate of 5 lbs/million acfm assuming Bituminous Coal	9,000	-0.02	0.02	2.36	42.58	0.34	16.74	0.13	10.85	0.09	8.15	0.07	6.02	0.05
	10,000	-0.02	0.02	2.62	43.28	0.35	17.01	0.14	11.02	0.09	8.28	0.07	6.11	0.05
	11,000	-0.02	0.02	2.88	43.90	0.35	17.25	0.14	11.18	0.09	8.40	0.07	6.20	0.05
ACI System with an Existing Baghouse ACI with a Sorbent Injection Rate of 2 lbs/million acfm Assuming Bituminous Coal	9,000	-0.02	0.02	1.69	37.12	0.30	14.60	0.12	9.45	0.08	7.10	0.06	5.24	0.04
	10,000	-0.02	0.02	1.88	37.72	0.30	14.82	0.12	9.60	0.08	7.21	0.06	5.33	0.04
	11,000	-0.02	0.02	2.07	38.27	0.31	15.04	0.12	9.74	0.08	7.32	0.06	5.40	0.04
ACI System with an Additional Baghouse ACI + Full Baghouse with a Sorbent Injection Rate of 2 lbs/million acfm Assuming Bituminous Coal	9,000	-0.62	0.62	0.50	313.92	1.10	236.83	0.83	210.55	0.74	195.47	0.68	181.05	0.63
	10,000	-0.62	0.62	0.56	338.75	1.18	256.69	0.90	228.50	0.80	212.28	0.74	196.74	0.69
	11,000	-0.62	0.62	0.62	363.09	1.27	276.17	0.97	246.12	0.86	228.77	0.80	212.12	0.74

Note 1: The above cost estimates assume bituminous coal consumption.

Note 2: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the Sargent & Lundy cost models. For modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.

Eastern bituminous coals, by contrast, tend to produce fly ash with lower natural alkalinity. Though bituminous fly ash (classified as 'Class F' fly ash) may contain calcium, it tends to be present in a glassy matrix and unavailable for acid-base neutralization reactions.

To assess the extent of expected natural neutralization, resulting in large part from the alkalinity of the fly ash, the 2010 ICR[57] data was examined. According to that data, units burning some of the subbituminous coals without operating acid gas control technology emitted substantially lower HCl than would otherwise be expected if the emissions were based solely on the chlorine content of those coals. Comparing the assumed chlorine content of the subbituminous coals modeled in EPA Platform v6 with the estimated values based on responses to the 2010 ICR supports the EPA Platform v6 assumption that combustion of subbituminous and lignite coals results in a 95% reduction in HCl emissions relative to the assumed chlorine content of the coal.

5.5.2 HCl Removal Rate Assumptions for Existing and Potential Units

SO_2 emission controls on existing and new (potential) units provide the HCl reductions indicated in Table 5-14. New supercritical pulverized coal units (column 3) that the model builds include FGD (wet or dry) which is assumed to provide a 99% removal rate for HCl. For existing conventional pulverized coal units with pre-existing FGD (column 5), the HCl removal rate is assumed to be 5% higher than the reported SO_2 removal rate up to a maximum of 99% removal. In addition, for fluidized bed combustion units (column 4) with no FGD and no fabric filter, the HCl removal rate is assumed to be the same as the SO_2 removal rate up to a maximum of 95%. FBCs with fabric filters are assumed to have an HCl removal rate of 95%.

Table 5-14 HCl Removal Rate Assumptions for Potential (New) and Existing Units in v6

		Potential (New)	**Existing Units with FGD**	
Gas	**Controls ==>**	**Ultra-Supercritical Pulverized Coal with 30%/90% CCS**	**Fluidized Bed Combustion (FBC)**	**Conventional Pulverized Coal (CPC) with Wet or Dry FGD**
HCl	Removal Rate	99%	**Without fabric filter:** Same as reported SO_2 removal rate up to a maximum of 95% ––– **With fabric filter: 95%**	Reported SO_2 removal rate + 5% up to a maximum of 99%

5.5.3 HCl Retrofit Emission Control Options

The retrofit options for HCl emission control are discussed in detail in the following sub-sections and summarized in Table 5-15.

<u>Wet and Dry FGD</u>

In addition to providing SO_2 reductions, wet scrubbers (Limestone Forced Oxidation, LSFO) and dry scrubbers (Lime Spray Dryer, LSD) reduce HCl as well. For both LSFO and LSD the HCl removal rate is assumed to be 99% with a floor of 0.001 lbs/MMBtu. This is summarized in columns 2-5 of Table 5-15.

[57] Collection Effort for New and Existing Coal- and Oil-Fired Electricity Utility Steam Generating Units (EPA ICR No.2362.01 (OMB Control Number 2060-0631)

Table 5-15 Retrofit HCl and SO_2 Emission Control Performance Assumptions in v6

Performance Assumptions	Limestone Forced Oxidation (LSFO)		Lime Spray Dryer (LSD)		Dry Sorbent Injection (DSI)	
	SO_2	HCl	SO_2	HCl	SO_2	HCl
Percent Removal	98% with a floor of 0.06 lbs/MMBtu	99% with a floor of 0.001 lbs/MMBtu	95% with a floor of 0.08 lbs/MMBtu	99% with a floor of 0.001 lbs/MMBtu	50%	98% with a floor of 0.002 lbs/MMBtu
Capacity Penalty Heat Rate Penalty	Calculated based on characteristics of the unit: See Table 5-3		Calculated based on characteristics of the unit: See Table 5-3		Calculated based on characteristics of the unit: See Excerpt from Table 5-17	
Applicability	Units ≥ 25 MW		Units ≥ 25 MW		Units ≥ 25 MW	
Sulfur Content Applicability			Coals ≤ 3.0 lbs of SO_2/MMBtu		Coals ≤ 2.0 lbs of SO_2/MMBtu	
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, SE, LD, LE, LG, LH, PK, and WC		BA, BB, BD, BE, SA, SB, SD, SE, LD, and LE		BA, BB, BD, SA, SB, SD, and LD	

Dry Sorbent Injection

EPA Platform v6 includes dry sorbent injection (DSI) as a retrofit option for achieving (in combination with a particulate control device) both SO_2 and HCl removal. In DSI for HCl reduction, a dry sorbent is injected into the flue gas duct where it reacts with the HCl and SO_2 in the flue gas to form compounds that are then captured in a downstream fabric filter or electrostatic precipitator (ESP) and disposed of as waste. A sorbent is a material that takes up another substance by either adsorption on its surface or absorption internally or in solution. A sorbent may also chemically react with another substance. The sorbent assumed in the cost and performance characterization discussed in this section is Trona (sodium sesquicarbonate), a sodium-rich material with major underground deposits found in Sweetwater County, Wyoming. Trona is typically delivered with an average particle size of 30 µm diameter but can be reduced to about 15 µm through onsite in-line milling to increase its surface area and capture capability. While the Sargent & Lundy description of the DSI technology includes references to the hydrated lime option, only the Trona option is implemented in EPA Platform v6.

Removal rate assumptions: The removal rate assumptions for DSI are summarized in Table 5-15. The assumptions shown in the last two columns of Table 5-15 were derived from assessments by EPA engineering staff in consultation with Sargent & Lundy. As indicated in this table, the assumed SO_2 removal rate for DSI + fabric filter is 50%. The retrofit DSI option on an existing unit with existing ESP is always provided in combination with a fabric filter (Toxecon configuration).

Methodology for Obtaining DSI Control Costs: The cost and performance model for DSI was updated by Sargent & Lundy. The model is used to derive the cost of DSI retrofits with two alternatives, associated particulate control devices, i.e., ESP and fabric filter. The cost model notes that the cost drivers of DSI are quite different from those of wet or dry FGD. Whereas plant size and coal sulfur rates are key underlying determinants of FGD cost, sorbent feed rate and fly ash waste handling are the main drivers of the capital cost of DSI, with plant size and coal sulfur rates playing a secondary role.

Furthermore, the DSI sorbent feed rate and variable O&M costs are based on assumptions that a fabric filter and in-line Trona milling are used, and that the SO_2 removal rate is 50%. The corresponding HCl removal effect is estimated to be 98% for units with fabric filter.

The cost of fly ash waste handling, which is the other key contributor to DSI cost, is a function of the type of particulate capture device and the flue gas SO_2.

Total waste production involves the production of both reacted and unreacted sorbent and fly ash. Sorbent waste is a function of the sorbent feed rate with an adjustment for excess sorbent feed. Use of sodium-based DSI may make the fly ash unsalable, which would mean that any fly ash produced must be landfilled along with the reacted and unreacted sorbent waste. Typical ash contents for each fuel are used to calculate a total fly ash production rate. The fly ash production is added to the sorbent waste to account for the total waste stream for the variable O&M analysis.

For purposes of modeling, the total variable O&M includes the first two component costs noted in the previous paragraph, i.e., the costs for sorbent usage and the costs associated with waste production and disposal.

Table 5-16 presents the capital, fixed O&M, variable O&M costs as well as the capacity and heat rate penalties of a DSI retrofit for an illustrative and representative set of generating units with the capacities and heat rates indicated. For details of Sargent & Lundy DSI cost model, see Attachment 5-7.

5.6 Fabric Filter (Baghouse) Cost Development

Fabric filters are not endogenously modeled as a separate retrofit option. In EPA Platform v6, an existing or new fabric filter particulate control device is a pre-condition for installing a DSI retrofit, and the cost of these retrofits at plants without an existing fabric filter include the cost of installing a new fabric filter. This cost was added to the DSI costs discussed in section 5.5. The costs associated with a new fabric filter retrofit are derived from the cost and performance updated by Sargent & Lundy. Similarly, dry scrubber retrofit costs also include the cost of a fabric filter.

The engineering cost analysis is based on a pulse-jet fabric filter which collects particulate matter on a fabric bag and uses air pulses to dislodge the particulate from the bag surface and collect it in hoppers for removal via an ash handling system to a silo. This is a mature technology that has been operating commercially for more than 25 years. “Baghouse” and “fabric filters” are used interchangeably to refer to such installations.

Capital Cost: The major driver of fabric filter capital cost is the air-to-cloth (A/C) ratio. The A/C ratio is defined as the volumetric flow, (typically expressed in Actual Cubic Feet per Minute, ACFM) of flue gas entering the baghouse divided by the areas (typically in square feet) of fabric filter cloth in the baghouse. The lower the A/C ratio, e.g., A/C = 4.0 compared to A/C = 6.0, the greater the area of the cloth required and the higher the cost for a given volumetric flow. An A/C ratio of 4.0 is used in EPA Platform v6, and it is assumed that the existing ESP remains in place and active.

Table 5-17 presents the capital, fixed O&M, variable O&M costs for fabric filters as represented in EPA Platform v6 for an illustrative set of generating units with a representative range of capacities and heat rates. See Attachment 5-9 for details of the Sargent & Lundy fabric filter PM control cost model.

Table 5-16 Illustrative Dry Sorbent Injection (DSI) Costs (2019$) for Representative Sizes and Heat Rates in v6

Control Type	Heat Rate (Btu/kWh)	SO_2 Rate (lb/ MMBtu)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
						100		300		500		700		1000	
						Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
DSI Assuming Bituminous Coal	9,000	2.0	-0.37	0.37	6.24	132.4	3.80	60.3	1.40	41.8	0.88	32.9	0.66	25.5	0.48
	10,000	2.0	-0.41	0.41	6.94	136.5	3.84	62.2	1.41	43.1	0.89	33.9	0.66	26.3	0.49
	11,000	2.0	-0.45	0.45	7.64	140.3	3.87	63.9	1.43	44.3	0.90	34.8	0.67	27.0	0.49

Note 1: A SO_2 removal efficiency of 50% is assumed in the above calculations.

Note: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the Sargent & Lundy cost models. For modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.

Table 5-17 Illustrative Particulate Controls Costs (2019$) for Representative Sizes and Heat Rates in v6

Coal Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
Bituminous	9,000	-0.60	0.60	0.06	271	0.9	220	0.8	200	0.7	187	0.7	175	0.6
	10,000			0.07	295	1.0	240	0.8	217	0.8	204	0.7	191	0.7
	11,000			0.07	319	1.1	259	0.9	235	0.8	220	0.8	206	0.7

Note: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the Sargent & Lundy cost models. For modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.

5.7 Coal-to-Gas Conversions[58]

In EPA Platform v6, existing coal plants are given the option to burn natural gas by investing in a coal-to-gas retrofit. There are two components of cost in this option: boiler modification costs and the cost of extending natural gas lateral pipeline spurs from the boiler to a natural gas main pipeline. These two components of cost and their associated performance implications are discussed in the following sections.

5.7.1 Boiler Modifications for Coal-To-Gas Conversions

Enabling natural gas firing in a coal boiler typically involves installation of new gas burners and modifications to the ducting, windbox (i.e., the chamber surrounding a burner through which pressurized air is supplied for fuel combustion), and possibly to the heating surfaces used to transfer energy from the exiting hot flue gas to steam (referred to as the convection pass). It may also involve modification of environmental equipment. Engineering studies are performed to assess operating characteristics like furnace heat absorption and exit gas temperature; material changes affecting piping and components like superheaters, reheaters, economizers, and recirculating fans; and operational changes to soot blowers, spray flows, air heaters, and emission controls.

The following table summarizes the cost and performance assumptions for coal-to-gas boiler modifications as incorporated in EPA Platform v6. The values in the table were developed by EPA's engineering staff based on technical papers[59] and discussions with industry engineers familiar with such projects. They were designed to be broadly applicable across the existing coal fleet (with the exceptions noted in the table). Coal-to-gas retrofit options in EPA Platform v6 force a permanent change in fuel type from coal to natural gas. Coal therefore can no longer be fired.

Table 5-18 Cost and Performance Assumptions for Coal-to-Gas Retrofits in v6

Factor	Description	Notes
Applicability:	Existing pulverized coal (PC) fired and cyclone boiler units of a size greater than 25 MW:	Not applicable for fluidized bed combustion (FBC) and stoker boilers.
Capacity Penalty:	None	The furnace of a boiler designed to burn coal is oversized for natural gas, and coal boilers include equipment, such as coal mills, that are not needed for gas. As a result, burning gas should have no impact on net power output.
Heat Rate Penalty:	+ 5%	When gas is combusted instead of coal, the stack temperature is lower and the moisture loss to stack is higher. This reduces efficiency, which is reflected in an increase in the heat rate.
Incremental Capital Cost:	PC units: (2019$)/kW = 305.71*(75/MW)^0.35 Cyclone units: (2019$)/kW = 427.99*(75/MW)^0.35	The cost function covers new gas burners and piping, windbox modifications, air heater upgrades, gas recirculating fans, and control system modifications. <u>Example for 50 MW PC unit:</u> $/kW = 305.71*(75/50)^0.35 = 352.32
Incremental Fixed O&M:	-33% FOM cost of the existing coal unit	Due to reduced needs for operators, maintenance materials, and maintenance staff when natural gas combusted, FOM costs decrease by 33%.

[58] As discussed here coal-to-gas conversion refers to the modification of an existing boiler to allow it to fire natural gas. It does not refer to the addition of a gas turbine to an existing boiler cycle, the replacement of a coal boiler with a new natural gas combined cycle plant, or to the gasification of coal for use in a natural gas combustion turbine.

[59] For an example see Babcock and Wilcox's White Paper MS-14 "Natural Gas Conversions of Exiting Coal-Fired Boilers" 2010 (https://slidex.tips/download/natural-gas-conversions-of-existing-coal-fired-boilers).

Factor	Description	Notes
Incremental Variable O&M:	-25% VOM cost of the existing coal unit	Due to reduced waste disposal and miscellaneous other costs, VOM costs decrease by 25%.
Fuel Cost:	Natural Gas	To obtain natural gas the unit incurs the cost of extending lateral pipeline spurs from the boiler to the local transmission mainline. See Section 5.7.2.
NO_x emission rate:	50% of existing coal unit NO_x emission rate, with a floor of 0.05 lbs/MMBtu	The 0.05 lbs/MMBtu floor is the same as the NO_x rate floor for new retrofit SCR on units burning subbituminous coal.
SO_2 emissions:	Zero	

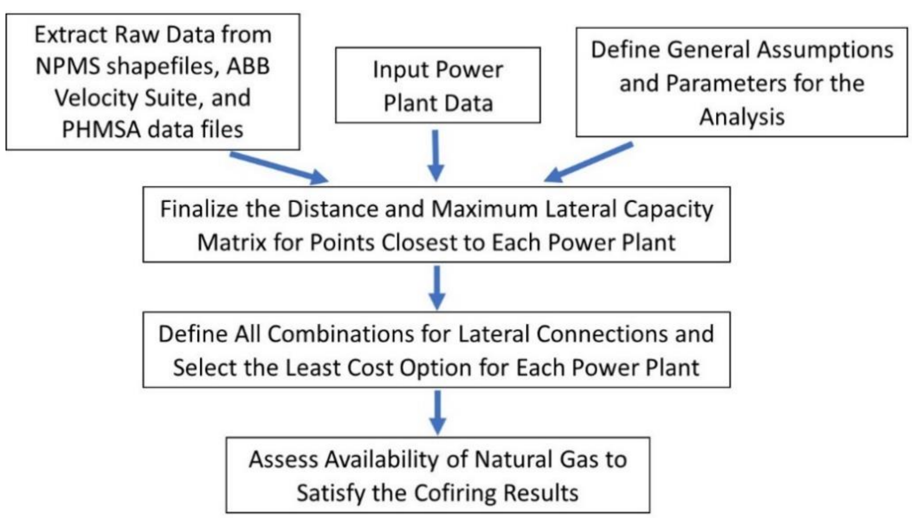
5.7.2 Natural Gas Pipeline Requirements for Coal-To-Gas Conversions

For every individual coal facility in the U.S., the distance and associated cost of constructing pipeline laterals from each facility to the interstate natural gas pipeline system was determined. Table 5-21 shows the pipeline costing results for each qualifying existing coal-fired unit in EPA Platform v6.

The lateral costs represent the minimum cost to connect coal power plants to the closest pipelines so that the plants can use natural gas. The estimated costs include both the cost for the lateral based on its mileage and size and the compression needed to support the movement of incremental gas needed for cofiring. They do not, however, include costs for mainline transport beyond those represented by the gas basis in EPA Platform v6. Thus, it is implicit that all gas needed to fire the plants would be purchased on a spot basis, and mainline expansion will not be needed to support the transport of incremental gas associated with cofiring beyond the amounts included in the EPA Base Case. This assumption will hold so long as the gas needed to support coal-to-gas conversion is not overly concentrated at specific locations during specific times of the year on gas pipeline systems in those areas are being highly utilized.

The process for estimating the lateral costs is shown in Figure 1 below. A general description of the process follows.

Figure 5-1 Process for Lateral Cost Estimation



First, the raw data for pipelines is extracted from *National Pipeline Mapping System (NPMS)* shapefiles that contain maps of pipelines throughout the United States, published by the *U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA)*. The NPMS shapefiles contain thousands of data points that are used to digitally map over 300 pipelines across the U.S. The

NPMS shapefiles *are preprocessed along with ABB Velocity Suite data provided by Hitachi Energy and with data from the PHMSA Natural and Other Gas Transmission and Gathering Pipeline Systems Annual Report Part H* database to provide pipeline distance and diameter information. This initial step of the process extracts the necessary raw data from the three different data sets, including the pipeline ID, location, and diameter of the closest 50 points to each power plant.

The second step defines the necessary data for each power plant considered in the analysis. The most relevant data includes the location, size, and heat rate of the power plant, the amount of gas needed by the plant for converting to natural gas, and the lateral cost factor on a dollar-per-inch-mile basis.

The third step defines lateral assumptions for each plant. Broad assumptions have been made as well as direct assumptions for the configuration of laterals for each power plant included in the analysis. They include assumptions for the maximum distance that can be considered for each lateral connection and the potential offtake from each pipeline point.

Using the raw data, power plant information, and the general assumptions from steps 1, 2, and 3, the fourth step in the process finalizes the distances to and pipeline capacity of the pipelines closest to each power plant. This step of the process defines values for the matrix of mileage and lateral capacity for up to 20 laterals for each plant that are subsequently applied in the optimization analysis.

Step five sets up the matrix for all lateral options. The analysis assumes that up to two laterals may be applied for each power plant, and the capacity and costs for the lateral combinations for each power plant are defined. The matrix of lateral combinations considers both the distance and size of each lateral. Diameters from 4” to 32” in 2” increments are considered in the size matrix, yielding a total of up to 43,050 combinations of laterals that could serve each plant. This matrix includes 300 single lateral options, i.e., 15 different lateral diameters for each of the 20 potential pipeline connections, plus 42,750 2-lateral options that work through all combinations of lateral diameter and pipeline connections applying two different laterals to serve each plant.

After the lateral option matrix has been fully populated, the option from the 43,050 combinations that satisfies a power plant’s natural gas need at the lowest cost is selected.

5.8 Retrofit Assignments

In IPM, model plants that represent existing generating units have the option of maintaining their current system configuration, retrofitting with pollution controls, or retiring. The decision to retrofit or retire is endogenous to IPM and based on the least cost approach to meeting demand subject to modeled system and operational constraints. IPM is capable of modeling retrofits and retirements at each applicable model unit at three different points in time, referred to as three stages. At each stage a retrofit set may consist of a single retrofit (e.g., LSFO Scrubber) or pre-specified combinations of retrofits (e.g., ACI + LSFO Scrubber + SCR). In EPA Platform v6, first stage retrofit options are provided to existing coal-steam and oil/gas steam plants. These plants, along with others such as combined cycle, combustion turbines, biomass, and nuclear plants, are also given retirement as an option in stage one. Third stage retrofit options are offered to coal-steam plants only.

Table 5-19 presents the first stage retrofit options available by plant type. Table 5-20 presents the second and third stage retrofit options available to coal-steam plants. The cost of multiple retrofits on the same model plant, whether installed in one or multiple stages, is additive. In EPA Platform v6, projections of pollution control equipment capacity and retirements are limited to the pre-specified combinations listed in Table 5-19 and Table 5-20.

Table 5-19 First Stage Retrofit Assignment Scheme in v6

Plant Type	Retrofit Option 1st Stage	Criteria
Coal Steam		
	Coal Retirement	All coal steam boilers
	Coal Steam SCR	All coal steam boilers that are 25 MW or larger and do not possess an existing SCR control option
	Coal Steam SNCR – Non FBC Boilers	All non FBC coal steam boilers that are 25 MW or larger and do not possess an existing post combustion NO_x control option
	Coal Steam SNCR – FBC Boilers	All coal FBC units that are 25 MW or larger and do not possess an existing post combustion NO_x control option
	LSD Scrubber	All unscrubbed coal steam boilers 25 MW or larger and burning less than 3 lbs/MMBtu SO_2 coal
	LSFO Scrubber	All unscrubbed and non FBC coal steam boilers 25 MW or larger
	CO_2 Capture and Storage	All scrubbed coal steam boilers 400 MW or larger
	ACI - Hg Control Option (with and without Toxecon)	All coal steam boilers larger than 25 MW that do not have an ACI and have an Hg EMF greater than 0.1. Actual ACI technology type will be based on the boilers fuel and technology configuration. See discussion in Chapter 5.
	LSD Scrubber + SCR	Combination options – Individual technology level restrictions apply
	LSD Scrubber + SNCR	
	LSFO Scrubber + SCR	
	LSFO Scrubber + SNCR	
	ACI + SCR	
	ACI + SNCR	
	ACI + LSD Scrubber	
	ACI + LSFO Scrubber	
	ACI + LSD Scrubber + SCR	
	ACI + LSFO Scrubber + SCR	
	ACI + LSD Scrubber + SNCR	
	ACI + LSFO Scrubber + SNCR	
	DSI	All unscrubbed and non FBC coal steam boilers 25 MW or larger with Fabric Filter and burning less than 2 lbs/MMBtu SO_2 coal.
	DSI + Fabric Filter	All unscrubbed and non FBC-coal steam boilers 25 MW or larger without Fabric Filter, with CESP or HESP, and burning less than 2 lbs/MMBtu SO_2 coal.
	DSI + SCR	Combination options – Individual technology level restrictions apply
	DSI + SNCR	
	ACI + DSI	
	ACI + DSI + SCR	
	ACI + DSI + SNCR	
	Heat Rate Improvement	All coal steam boilers with a heat rate larger than 9,500 Btu/kWh
	Coal-to-Gas	All coal steam boilers that are 25 MW or larger
Integrated Gasification Combined Cycle		
	IGCC Retirement	All integrated gasification combined cycle units
Combined Cycle		
	CC Retirement	All combined cycle units
	CO_2 Capture and Storage	All combined cycle sets 400 MW or larger
Combustion Turbine		
	CT Retirement	All combustion turbine units
Nuclear		

Plant Type	Retrofit Option 1st Stage	Criteria
	Nuclear Retirement	All nuclear power units
Oil and Gas Steam		
	Oil/Gas Retirement	All oil/gas steam boilers
	Oil/Gas Steam SCR	All oil/gas steam boilers 25 MW or larger that do not possess an existing post combustion NO_x control option

Table 5-20 Second and Third Stage Retrofit Assignment Schemes in v6

Plant Type	Retrofit Option 1st Stage	Retrofit Option 2nd Stage	Retrofit Option 3rd Stage
Coal Steam			
	NO_x Control Option[1]	SO_2 Control Option	Heat Rate Improvement
		HCl Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	SO_2 Control Option[2]	NO_x Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	Hg Control Option[3]	NO_x Control Option	Heat Rate Improvement
		SO_2 Control Option	Heat Rate Improvement
		HCl Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	CO_2 Control Option[4]	None	None
	NO_x Control Option[1] + SO_2 Control Option[2]	CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	NO_x Control Option[1] + Hg Control Option[3]	SO_2 Control Option	Heat Rate Improvement
		HCl Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	SO_2 Control Option[2] + Hg Control Option[3]	NO_x Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	NO_x Control Option[1] + SO_2 Control Option[2] + Hg Control Option[3]	CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	HCl Control Option[5]	NO_x Control Option	Heat Rate Improvement
		SO_2 Control Option	Heat Rate Improvement
		Heat Rate Improvement	None
		Coal Retirement	None
	NO_x Control Option[1] + HCl Control Option[5]	SO_2 Control Option	Heat Rate Improvement
		Heat Rate Improvement	None
		Coal Retirement	None
	Hg Control Option[3] + HCl Control Option[5]	NO_x Control Option	Heat Rate Improvement
		SO_2 Control Option	Heat Rate Improvement
		Heat Rate Improvement	None
		Coal Retirement	None
		SO_2 Control Option	Heat Rate Improvement
		Heat Rate Improvement	None

Plant Type	Retrofit Option 1st Stage	Retrofit Option 2nd Stage	Retrofit Option 3rd Stage
	NO_x Control Option[1] + HCl Control Option[5] + Hg Control Option[3]	Coal Retirement	None
	Heat Rate Improvement	NO_x Control Option	None
		SO_2 Control Option	None
		HCl Control Option	None
		CO_2 Control Option	None
		Coal Retirement	None
	Coal-to-Gas	NO_x Control Option	None
		Oil/Gas Retirement	None
	Coal Retirement	None	None
Combined Cycle			
	CO_2 Capture and Storage	CC Retirement	None
Oil and Gas Steam			
	NO_x Control Option[1]	Oil/Gas Retirement	None
	Oil/Gas Retirement	None	None

Notes:

[1]"NO_x Control Option" implies that a model plant may be retrofitted with one of the following NO_x control technologies: SCR, SNCR - non-FBC, or SNCR - FBC

[2]"SO_2 Control Option" implies that a model plant may be retrofitted with one of the following SO_2 control technologies: LSFO scrubber or LSD scrubber

[3]"Hg Control Option" implies that a model plant may be retrofitted with one of the following activated carbon injection technology options for reduction of mercury emissions: ACI or ACI + Toxecon

[4]"CO_2 Control Option" implies that a model plant may be retrofitted with carbon capture and storage technology

[5]"HCl Control Option" implies that a model plant may be retrofitted with a DSI (with milled Trona)

<u>List of tables and attachments that are directly uploaded to the web:</u>

Table 5-21 Cost of Building Pipelines to Coal Plants in EPA Platform v6 Post-IRA 2022 Reference Case

Attachment 5-1 Wet FGD Cost Methodology

Attachment 5-2 SDA FGD Cost Methodology

Attachment 5-3 SCR Cost Methodology for Coal-Fired Boilers

Attachment 5-4 SCR Cost Methodology for Oil-Gas-Fired Boilers

Attachment 5-5 SNCR Cost Methodology for Coal-Fired Boilers

Attachment 5-6 SNCR Cost Methodology for Oil-Gas-Fired Boilers

Attachment 5-7 DSI Cost Methodology

Attachment 5-8 Hg Cost Methodology

Attachment 5-9 PM Cost Methodology

Attachment 5-10 Combustion Turbine NO_x Control Technology Memo