FLAT FILE GENERATION METHODOLOGY

Version: EPA Base Case v.5.14
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Content

SECTION I: INTRODUCTION

This document provides the flat file generation methodology for EPA Base Case v.5.14. The methodology takes EPA Base Case v.5.14 using Integrated Planning Model (IPM®) run results (parsed outputs) and generates the formatted flat file that the U.S. Environmental Protection Agency (U.S. EPA) uses as input into air quality modeling framework. Section II provides data descriptions and sources. Section III describes data processing steps in detail. Section IV describes the layout of the formatted flat file.

SECTION II: DATA SOURCES AND DESCRIPTIONS

IPM run results that have been disaggregated into the unit, emission control technology and fuel type are the key input. These results include records of fossil-fired existing and retrofit units, along with committed and new-build aggregates. All fossil and biomass fired units are included in the resultant formatted flat file as needed for air quality modeling inputs. Other non fossil plant types that are part of the EPA Base Case v.5.14 modeled results (nuclear, hydro, wind, solar PV, solar thermal, geothermal, landfill gas, non-fossil waste, municipal solid waste, fuel cell, tires and pumped storage) are not included in the flat file.

The committed and new-build aggregates are hereafter referred to as "generic" aggregates. All records contain the following:

1. Population characteristics including state FIPS codes, county FIPS codes, recognized ORIS codes (<80000) and unit IDs for existing and retrofit units. Generic aggregates have state level information only.
2. Sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) control information for existing and retrofit units as well as generic aggregates.
3. Annual and seasonal heat input (TBtu).
4. Heat contents (MMBtu/ton, k-gallon, MMcf) and SO_2 and ash contents (lb/MMBtu).
5. Annual and summer NO_x emissions (MTon), annual SO_2 emissions (MTon), HCL emissions (MTon), and mercury emissions (Ton).

Table 1 provides the rest of the input data's descriptions, sources and file locations. The FlatFile_Inputs spreadsheet is included as an attachment to this documentation. The spreadsheet contains large amount of data including NEEDS v.5.14 plant's state FIPS code, county FIPS code, county's most recent 8 hour ozone or PM2.5 attainment/non-attainment status, ORIS code, latitude-longitude coordinates, zip code, Emission Inventory System (EIS) unit-specific data (unit facility name, facility code, boiler ID, tribal code, reg code, NAICS, longitude, latitude, facility ID, unit ID, rel point ID, process ID, agency facility ID, agency unit ID, agency rel point ID, agency process ID, stack height, stack diameter, stack temperature, stack flow, and stack velocity), filterable PM10 and filterable PM2.5 control efficiencies and sulfur and ash contents by ORIS code.

Table 1. Input Data Descriptions, Sources and Locations

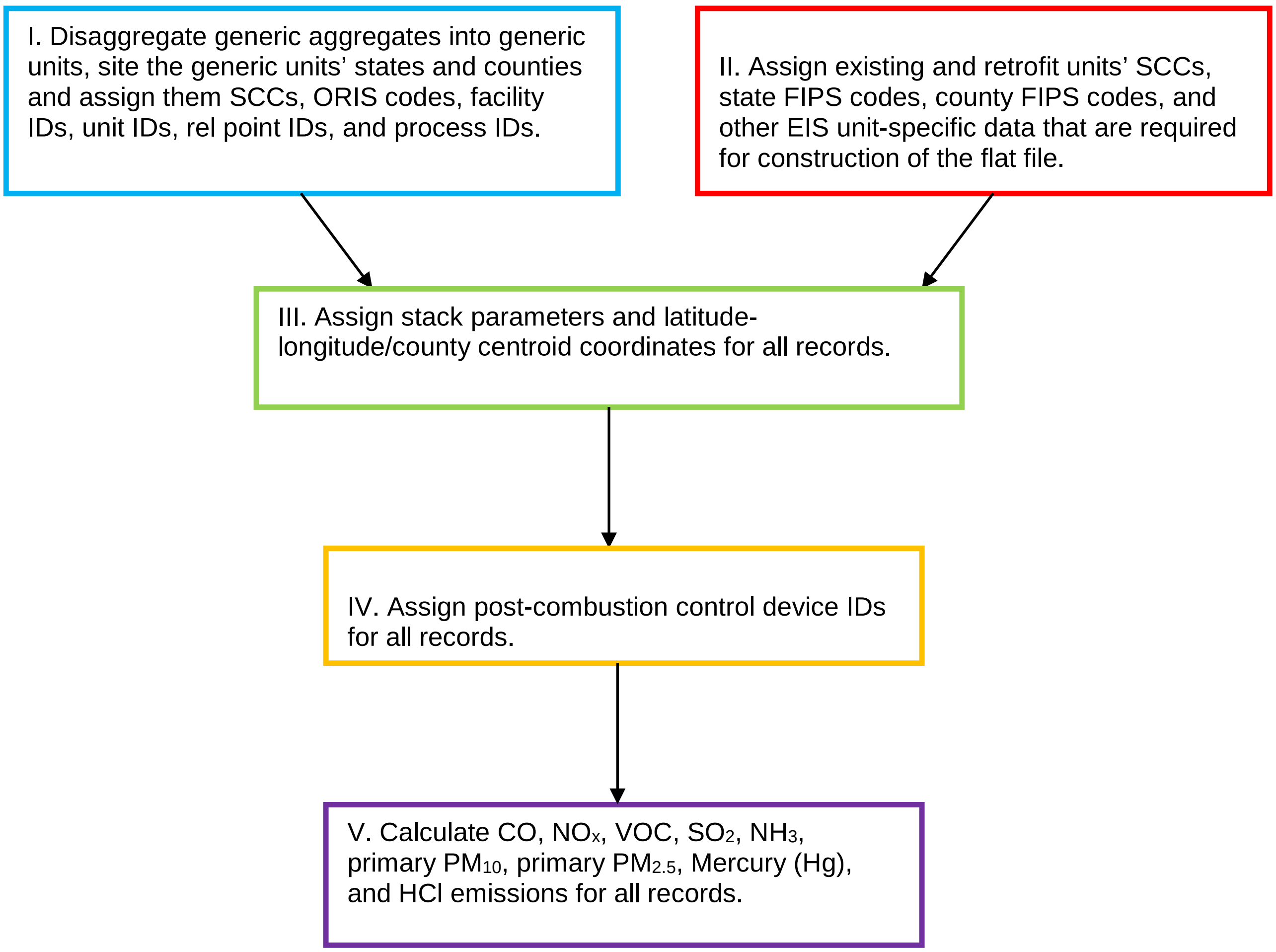
No.	Input	Description	Source	Location
1	EIS	This file contains Emission Inventory System (EIS) unit-specific data that include unit facility name, facility code, boiler ID, tribal code, reg code, NAICS, longitude, latitude, facility ID, unit ID, rel point ID, process ID, agency facility ID, agency unit ID, agency rel point ID, agency process ID, stack height, stack diameter, stack temperature, stack flow, and stack velocity.	EPA	FlatFile_Inputs.xls
2	GenericUnitSite	This file contains all existing plants that serve as sister plants in siting generic units. The data include NEEDS v.5.14 plant's state FIPS code, county FIPS code, county's most recent 8 hour ozone or $PM_{2.5}$ attainment/non-attainment status, ORIS code, latitude-longitude coordinates, and zip code.	EPA	FlatFile_Inputs.xls

No.	Input	Description	Source	Location
3	LatLonDefault	This file contains latitude-longitude coordinates by ORIS code, state FIPS code and county FIPS code.	EPA	FlatFile_Inputs.xls
4	SCC	This file contains Source Classification Codes (SCCs) by plant type, fuel type, coal rank, firing and bottom type (for boilers).	EPA	Table 6
5	PlantTypeStackParameters	This file contains default stack parameters (height, diameter, temperature and velocity) by plant type.	EPA	Table 7
6	SCCDefaultStackParameters	This file contains default stack parameters (height, diameter, temperature and velocity) by SCC.	EPA	Table 8
7	ControlDevices	This file contains post-combustion control devices and their associated control IDs.	EPA	Table 9
8	SCCDefaultHeatContent	This file contains default heat contents by SCC.	EPA	Table 10
9	SCCEmsFac	This file contains emission factors for carbon monoxide (CO), volatile organic compounds (VOC), ammonia (NH_3), filterable particulate matter less than or equal to 10 microns (filterable PM_{10}), filterable particulate matter less than or equal to 2.5 microns (filterable $PM_{2.5}$), primary PM_{10} and primary $PM_{2.5}$ by SCC.	EPA	Table 11
10	PMSulfurAshContentDefault	This file contains default filterable PM_{10} and filterable $PM_{2.5}$ control efficiencies and sulfur and ash contents by plant type and fuel type and coal rank.	EPA	Table 12
11	PMCDEmsFac	This file contains PM condensable emission factors by SCC.	EPA	Table 13
12	PMAdjustmentRatio	This file contains primary PM_{10} and primary $PM_{2.5}$ emission factors (EF) by SCC for gas-fired units (including IGCC).	EPA	Table 14
13	PMSulfurAshContent	This file contains filterable PM_{10} and filterable $PM_{2.5}$ control efficiencies and sulfur and ash contents by ORIS code, unit ID, plant type and fuel type. The filterable PM_{10} and filterable $PM_{2.5}$ control efficiencies are based on 2001 data.	EPA	FlatFile_Inputs.xls

SECTION III: DETAILED DATA PROCESSING

Flow Chart 1 describes general data processing steps. A more detailed description of each step is provided in the subsections followed.

Flow Chart 1. Data Processing Steps



I. Disaggregate generic aggregates into generic units, site the generic units' states and counties and assign them SCCs, ORIS codes, facility IDs, unit IDs, rel point IDs, and process IDs.

Generic unit data are prepared by transforming the generic aggregates into units similar to existing units in terms of the available data. First, the generic aggregates are disaggregated to create generic units. Second, the generic units are then sited and given state, county and county-centroid based latitude-longitude coordinates. Third, the generic units are assigned SCCs, ORIS codes, facility IDs, unit IDs, rel point IDs and process IDs. This process is performed in three steps as described in Flow Chart 2.

Flow Chart 2. Generic Unit Processing

1. Create generic units

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2. Site generic units

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3. Assign generic units SCCs, ORIS codes, facility IDs, unit IDs, rel point IDs, and process IDs.

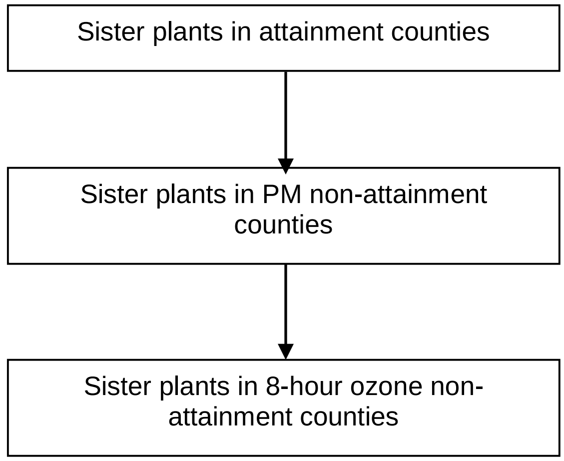
1. Create generic units: Generic aggregates are first disaggregated to create generic units. The process entails two steps: i. The generic aggregates are first aggregated by state, plant type and, for coal steam and IGCC, and coal rank. ii. They are then split into smaller generic units by dividing the aggregated capacity by a reference capacity. The result is the number of generic units to be created in a given state for each plant type and fuel type. The reference capacity is varied by plant type as shown in Table 2. Aggregated heat input and emissions are then divided evenly among all generic units created in a given state for each plant type.

Table 2. Generic Unit Reference Capacity

Plant Type	**Reference Capacity (MW)**
Biomass	600
Coal Steam	600
Combined Cycle	250
Combustion Turbine	160
Fossil Waste	030
IGCC	550
Oil/Gas Steam	100

2. Site generic units: The generic units are then given a state FIPS code, county FIPS code and latitude-longitude/county centroid based on an algorithm that sites generic units in counties within their respective states. The generic unit siting data file, GenericUnitSite, is used in this algorithm to assign each generic unit a sister plant that is in a county based on the county's attainment/non-attainment status. Within a state the hierarchy for assignment of sister plants in the order of county code then ORIS code is shown in Flow Chart 3. All generic units are sited so that their ORIS codes are unique, and the same ORIS code has the same county, latitude-longitude/county centroid across all runs of the same base case origin.

Flow Chart 3. Generic Unit Siting Hierarchy



3. Assign generic units SCCs, ORIS codes, facility IDs, unit IDs, rel point IDs and process IDs.

i. SCC assignment is based on unit's plant type, fuel type and coal rank as shown in Table 3.

ii. Generic unit's ORIS code consists of a six-digit number. The units are first sorted by plant type in the order of combined cycle, fossil waste, combustion turbine, IGCC, and coal steam. Generic units' ORIS codes are then assigned. The first digit of the ORIS code represents the unit's plant type as shown in Table 4. The next three digits are a counter, starting with "000" and incrementing with each generic unit created within a given state for each plant type. The last two digits are the state FIPS code. For example, the first combined-cycle generic unit sited in Arizona, which has a state FIPS code of "04", has an ORIS code of "700104".

iii. Generic unit's facility ID consists of a concatenation of the word "ORIS" and the unit's ORIS code. For example, the first combined-cycle generic unit in Arizona used in the example above has a plant ID of "ORIS700104".

iv. Generic unit's unit ID consists of a concatenation of a three-letter unit ID code representing the unit's plant type as shown in Table 5 and the unit's state FIPS code. For example, the first combined-cycle generic unit in Arizona used in the example above has a unit ID of "ORISGCC04".

v. Generic unit's rel point ID is the same as the unit's unit ID. For example, the first combined-cycle generic unit in Arizona in the example above has a point ID of "ORISGCC04".

vi. Generic unit's process ID is the same as the unit's facility ID.

Table 3. Generic Unit SCC

Plant Type	**Fuel Type / Coal Rank**	**SCC**
Coal Steam	Bituminous	10100202
Coal Steam	Subbituminous	10100222
Coal Steam	Lignite	10100301
Fossil Waste	Process Gas	10100701
Biomass	Biomass	10100902
Combined Cycle	Natural Gas	20100201
Combined Cycle	Oil	20100101
Combustion Turbine	Natural Gas	20100201
Combustion Turbine	Oil	20100101
IGCC	Coal	20100301
IGCC	Petroleum Coke	20100301
Oil/Gas Steam	Natural Gas	10100601

Table 4. Generic Unit 1st Digit ORIS Code

Plant Type	1st Digit of the ORIS Code
Biomass	3
Coal Steam	9
Combined Cycle	7
Combustion Turbine	8
Fossil Waste	5
IGCC	6
Oil/Gas Steam	4

Table 5. Generic Unit ID Code

Plant Type	Unit ID Code
Biomass	GSC
Coal Steam	GSC
Combined Cycle	GCC
Combustion Turbine	GGT
Fossil Waste	GFW
IGCC	IGC
Oil/Gas Steam	GSC

II. Assign existing and retrofit units' SCCs, state FIPS codes, county FIPS codes, and other EIS unit-specific data that are required for construction of the flat file.

1. Assign existing and retrofit units' SCCs. SCC, or Source Classification Code, describes a generating unit's characteristics. The assignment of SCC for existing and retrofit units is based on a unit's configuration that includes plant type, fuel type, and, if it's a boiler, firing and bottom type. The SCC is an eight-digit numeric code with specific meaning (starting at the left) in the first, third, and fifth through eighth digits. For the flat file, the first digit of the SCC represents the type of unit (boiler [=1] or turbine [=2]). The third digit of the SCC represents the economic sector of the unit (electric power sector=1). And the fifth through eighth digits of the SCC represent the unit's attributes including fuel type and, if a boiler, bottom and firing type. The second and fourth digits are zero. Table 6 displays the SCCs.

2. Assign existing and retrofit units' state FIPS codes, county FIPS codes, facility IDs, rel point IDs and process IDs. The units' state FIPS codes, county FIPS codes, facility IDs, rel point IDs, and process IDs are assigned from the EIS unit-specific data file, EIS. Where the EIS provides no data, default values are used. Appendix A describes the default values in detail.

Table 6. SCC Assignment for Existing and Retrofit Units

Plant Type	Boiler / Generator	Fuel Type / Coal Rank	Firing	Bottom	SCC
Coal Steam	Boiler/Generator	Bituminous		Wet	10100201
Coal Steam	Boiler/Generator	Bituminous	Vertical	Wet	10100201
Coal Steam	Boiler/Generator	Bituminous	Wall	Wet	10100201
Coal Steam	Boiler/Generator	Bituminous	Vertical	Dry	10100202
Coal Steam	Boiler/Generator	Bituminous	Wall	Dry	10100202
Coal Steam	Boiler/Generator	Bituminous		Dry	10100202
Coal Steam	Boiler/Generator	Bituminous			10100202
Coal Steam	Boiler/Generator	Bituminous	Wall		10100202

Plant Type	Boiler / Generator	Fuel Type / Coal Rank	Firing	Bottom	SCC
Coal Steam	Boiler/Generator	Bituminous	Vertical		10100202
Coal Steam		Bituminous	Turbo		10100202
Coal Steam	Boiler/Generator	Bituminous	Cyclone	Wet	10100203
Coal Steam	Boiler/Generator	Bituminous	Cyclone	Dry	10100203
Coal Steam	Boiler/Generator	Bituminous	Cyclone		10100203
Coal Steam	Boiler/Generator	Bituminous	Stoker/SPR	Wet	10100204
Coal Steam	Boiler/Generator	Bituminous	Stoker/SPR		10100204
Coal Steam	Boiler/Generator	Bituminous	Stoker/SPR	Dry	10100204
Coal Steam	Boiler/Generator	Bituminous	Tangential	Wet	10100211
Coal Steam	Boiler/Generator	Bituminous	Tangential		10100212
Coal Steam	Boiler/Generator	Bituminous	Tangential	Dry	10100212
Coal Steam	Boiler/Generator	Bituminous	Cell	Wet	10100215
Coal Steam	Boiler/Generator	Bituminous	Cell		10100215
Coal Steam	Boiler/Generator	Bituminous	Cell	Dry	10100215
Coal Steam	Boiler/Generator	Bituminous	FBC		10100218
Coal Steam	Boiler/Generator	Bituminous	FBC	Wet	10100218
Coal Steam	Boiler/Generator	Bituminous	FBC	Dry	10100218
Coal Steam	Boiler/Generator	Subbituminous		Wet	10100221
Coal Steam	Boiler/Generator	Subbituminous	Wall	Wet	10100221
Coal Steam	Boiler/Generator	Subbituminous	Vertical	Wet	10100221
Coal Steam	Boiler/Generator	Subbituminous			10100222
Coal Steam	Boiler/Generator	Subbituminous		Dry	10100222
Coal Steam	Boiler/Generator	Subbituminous	Vertical	Dry	10100222
Coal Steam	Boiler/Generator	Subbituminous	Wall	Dry	10100222
Coal Steam	Boiler/Generator	Subbituminous	Wall		10100222
Coal Steam	Boiler/Generator	Subbituminous	Cyclone	Dry	10100223
Coal Steam	Boiler/Generator	Subbituminous	Cyclone	Wet	10100223
Coal Steam	Boiler/Generator	Subbituminous	Cyclone		10100223
Coal Steam	Boiler/Generator	Subbituminous	Stoker/SPR		10100224
Coal Steam	Boiler/Generator	Subbituminous	Stoker/SPR	Wet	10100224
Coal Steam	Boiler/Generator	Subbituminous	Stoker/SPR	Dry	10100224
Coal Steam	Boiler/Generator	Subbituminous	Tangential	Wet	10100226
Coal Steam	Boiler/Generator	Subbituminous	Tangential	Dry	10100226
Coal Steam	Boiler/Generator	Subbituminous	Cell	Wet	10100235
Coal Steam	Boiler/Generator	Subbituminous	Cell	Dry	10100235
Coal Steam	Boiler/Generator	Subbituminous	Cell		10100235
Coal Steam	Boiler/Generator	Subbituminous	FBC	Dry	10100238
Coal Steam	Boiler/Generator	Subbituminous	FBC	Wet	10100238
Coal Steam	Boiler/Generator	Subbituminous	FBC		10100238
Coal Steam	Boiler/Generator	Lignite	Wall	Dry	10100301
Coal Steam	Boiler/Generator	Lignite		Wet	10100301
Coal Steam	Boiler/Generator	Lignite	Tangential	Wet	10100302
Coal Steam	Boiler/Generator	Lignite	Tangential	Dry	10100302

Plant Type	Boiler / Generator	Fuel Type / Coal Rank	Firing	Bottom	SCC
Coal Steam	Boiler/Generator	Lignite	Cyclone		10100303
Coal Steam	Boiler/Generator	Lignite	Cyclone	Wet	10100303
Coal Steam	Boiler/Generator	Lignite	Stoker/SPR	Wet	10100306
Coal Steam	Boiler/Generator	Lignite	Stoker/SPR		10100306
Coal Steam	Boiler/Generator	Lignite	Stoker/SPR	Dry	10100306
Coal Steam	Boiler/Generator	Lignite	FBC		10100318
Coal Steam	Boiler/Generator	Lignite	FBC	Wet	10100318
Coal Steam	Boiler/Generator	Lignite	FBC	Dry	10100318
O/G Steam	Boiler/Generator	Oil			10100401
O/G Steam	Boiler/Generator	Oil	Wall	Dry	10100401
O/G Steam	Boiler/Generator	Oil	Tangential		10100404
O/G Steam		Orimulsion	Wall		10100409
O/G Steam		Orimulsion	Other		10100409
O/G Steam	Boiler/Generator	Natural Gas			10100601
O/G Steam	Boiler/Generator	Natural Gas	Wall		10100601
O/G Steam	Boiler/Generator	Natural Gas	Wall	Dry	10100601
O/G Steam		Natural Gas	Wall	Wet	10100601
O/G Steam		Natural Gas	Vertical	Dry	10100601
O/G Steam		Natural Gas	Vertical		10100601
O/G Steam	_	Natural Gas	Cell	_	10100601
O/G Steam		Natural Gas	Cyclone	Dry	10100601
O/G Steam		Natural Gas	Cyclone	Wet	10100601
O/G Steam		Natural Gas	Cyclone		10100601
O/G Steam		Natural Gas	Other	Dry	10100601
O/G Steam		Natural Gas	Tangential	Dry	10100604
O/G Steam		Natural Gas	Tangential	Wet	10100604
O/G Steam	Boiler/Generator	Natural Gas	Tangential		10100604
Fossil Waste	Boiler	Process Gas			10100701
Coal Steam	Boiler/Generator	Petroleum Coke	Vertical	Dry	10100801
Coal Steam		Petroleum Coke	Wall		10100801
Coal Steam	Boiler/Generator	Petroleum Coke			10100801
Coal Steam	Boiler/Generator	Petroleum Coke	FBC	Dry	10100818
Coal Steam	Boiler/Generator	Biomass			10100902
Coal Steam	Boiler/Generator	Waste Coal			10102001
Coal Steam	Boiler/Generator	Waste Coal	Wall		10102001
Coal Steam	Boiler/Generator	Waste Coal	FBC		10102018
Combined Cycle	Generator	Oil			20100101
Combustion Turbine	Boiler/Generator	Oil			20100101
Combined Cycle	Boiler/Generator	Natural Gas			20100201
Combined Cycle		Natural Gas			20100201

Plant Type	Boiler / Generator	Fuel Type / Coal Rank	Firing	Bottom	SCC
Combustion Turbine	Boiler/Generator	Natural Gas			20100201
Fossil Waste	Generator	Process Gas			20100201
IGCC	Boiler/Generator				20100301

III. Assign stack parameters and latitude-*longitude/county centroid coordinates for all records.*

1. Assign stack parameters for all units: Existing and retrofit unit's stack parameters are assigned based on the hierarchy described in Flow Chart 4. Existing and retrofit units' stack parameters are first assigned based on a unit's plant type as shown in Table 7. If Table 7 provides no plant type-based stack parameters, the units are assigned EIS stack parameters from the EIS. Where the EIS data file provides no stack parameters, the units are assigned default stack parameters based on a unit's SCC as shown in Table 8. Generic units are assigned SCC-based default stack parameters. Units' stack flows are assigned from the EIS data file, except for IGCC units which receive default stack flow by plant type as shown in Table 7. Where the EIS data file provides no stack flow data, stack flows are calculated as follows:

$$Stack\ Flow\,(cft/sec) = 3.141592 * \left(\frac{Stack\ Diameter\ (ft)}{2}\right)^2 * Stack\ Velocity\ (ft/sec)$$

2. Assign latitude-longitude coordinates: Latitude-longitude coordinates are assigned from the EIS data file. If the EIS data file provides no data, latitude-longitude/county centroid coordinates are assigned based on a unit's sister ORIS code from the file "LatLonDefault."

Flow Chart 4. Stack Parameters Assignment Hierarchy

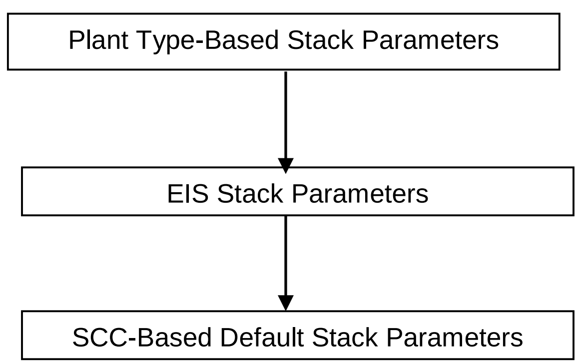


Table 7. Plant Type-Based Stack Parameters

Plant Type	Stack Height (ft)	Stack Diameter (ft)	Stack Temperature (degree F)	Stack Velocity (ft/sec)	Stack Flow (cft/sec)
IGCC	150	19	340	75.8	21491.48

Table 8. SCC-Based Default Stack Parameters

SCC	Stack Height (ft)	Stack Diameter (ft)	Stack Temperature (ºF)	Stack Velocity (ft/sec)
10100201	603.2	19.8	281.2	076.5
10100202	509.7	14.6	226.0	062.0
10100203	491.6	16.6	278.4	080.5
10100204	225.0	00.6	067.2	002.4
10100211	490.0	17.4	280.0	076.4
10100212	445.6	17.4	275.2	077.6
10100215	509.7	14.6	226.0	062.0
10100218	399.3	10.8	245.6	040.1
10100221	983.0	22.8	350.0	110.0
10100222	468.5	16.0	254.7	065.6
10100223	446.8	15.9	308.0	093.6
10100224	255.5	10.0	251.3	015.3
10100226	495.8	18.9	259.2	091.2
10100235	468.5	16.0	254.7	065.6
10100238	600.0	22.5	315.0	078.0
10100301	427.5	22.3	232.8	074.2
10100302	483.5	21.0	229.4	092.4
10100303	462.0	21.7	271.3	072.5
10100306	300.0	07.2	441.0	067.0
10100318	326.7	12.3	326.7	074.7
10100401	252.9	10.1	258.1	042.6
10100404	322.1	14.0	301.8	062.8
10100409	252.9	10.1	258.1	042.6
10100601	263.9	10.3	236.0	046.9
10100604	308.0	15.2	275.2	066.0
10100701	239.2	09.4	238.0	042.3
10100801	371.3	05.5	122.4	020.4
10100818	399.3	10.8	245.6	040.1
10100902	303.4	03.3	137.7	016.1
10102001	509.7	14.6	226.0	062.0
10102018	399.3	10.8	245.6	040.1
20100101	057.7	09.6	655.8	064.9
20100201	062.0	10.0	585.3	061.3
20100301	150.0	19.0	340.0	075.8

IV. Assign post-combustion control device IDs for all records.

Control IDs are assigned to reflect all post-combustion control devices installed at a unit. The control devices can be installed at either existing or retrofit level, or both. Table 9 lists the control devices and their associated control IDs.

Table 9: Post-Combustion Control Devices

Control ID	Description
119	Dry FGD
139	SCR
140	SNCR or other NO_x
141	Wet FGD
206	DSI
207	ACI

V. Calculate CO, NO_x, VOC, SO_2, NH_3, primary PM_{10}, primary $PM_{2.5}$, Mercury (Hg), and HCl emissions for all records.

Emissions are calculated at three levels: annual, seasonal and monthly emissions.

1. Annual emission calculations

i. Annual NO_x, SO_2, mercury (Hg), and HCl emissions (tons) are taken directly from IPM run results.

ii. Annual CO, VOC and NH_3 emissions (tons) are calculated by multiplying the unit's fuel use and uncontrolled emission factors for CO, VOC and NH_3 as follows:

$$Annual\ Emissions_{Pollutant}\ (tons) =$$

$$\frac{Annual\ Fuel\ Use\ (ton,k-gallon,MMcf) * Emission\ Factor_{Pollutant}\ (lb/ton,k-gallon,MMcf)}{2000\ (lb/ton)}$$

Where:

2000 converts lb to short ton and the pollutants are CO, VOC, and NH_3.

$Annual\ Fuel\ Use\ (ton, k-gallon, MMcf)$ is calculated from IPM run results, which are in MMBtu of annual heat input and converted into physical units of annual fuel use as follows:

$$Fuel\ Use\ (ton, k-gallon, MMcf) = \frac{Heat\ Input\ (MMBtu)}{Heat\ Content\ (MMBtu/ton, k-gallon, MMcf)}$$

Where $Heat\ Content\ (MMBtu/ton, k-gallon, MMcf)$ is assigned using EPA Base Case v.5.14 assumptions for coal and petroleum coke units. All other units are assigned default heat contents based on the unit's SCC as shown in Table 10.

Table 10: SCC-Based Default Heat Content (MMBtu/ton, K-gallon, MMcft)

SCC	Heat Content
10100401	0152
10100404	0152
10100409	0152
10100601	1024
10100604	1024
10100701	0671
10100902	0012
20100101	0138
20100201	1024

$UncontrolledEmission\ Factor_{Pollutant}\ (lb/ton,k-gallon,MMcf)$ is assigned for CO, VOC, NH_3 based on a unit's SCC as shown in Table 11.

Table 11: SCC-Based Emission Factors (lbs/ton, k-gal, MMcft)

SCC	CO EF	VOC EF	NH_3 EF	Filterable PM_{10} EF	Filterable $PM_{2.5}$ EF	PM Flag[1]
10100201	00.50	00.04	00.03	02.60	01.48	A
10100202	00.50	00.06	00.03	02.30	00.60	A
10100203	00.50	00.11	00.03	00.26	00.11	A
10100204	05.00	00.05	00.03	13.20	04.60	
10100211	00.50	00.04	00.03	02.60	01.48	A
10100212	00.50	00.06	00.03	02.30	00.60	A
10100215	00.50	00.06	00.03	02.30	00.60	A
10100218	18.00	00.05	00.03	12.40	01.36	
10100221	00.50	00.04	00.03	02.60	01.48	A
10100222	00.50	00.06	00.03	02.30	00.60	A
10100223	00.50	00.11	00.03	00.26	00.11	A
10100224	05.00	00.05	00.03	13.20	04.60	
10100226	00.50	00.06	00.03	02.30	00.60	A
10100235	00.50	00.06	00.03	02.30	00.60	A

SCC	CO EF	VOC EF	NH_3 EF	Filterable PM_{10} EF	Filterable $PM_{2.5}$ EF	PM Flag[1]
10100238	18.00	00.05	00.03	16.10	04.20	
10100301	00.25	00.07	00.03	01.80	00.52	A
10100302	00.60	00.07	00.03	02.30	00.66	A
10100303	00.60	00.07	00.03	00.87	00.37	A
10100306	05.00	00.07	00.03	01.60	00.56	A
10100318	00.15	00.03	00.03	12.00	01.40	
10100401	05.00	00.76	00.80	[2]	[3]	
10100404	05.00	00.76	00.80	[2]	[3]	
10100409	05.00	00.76	00.80	[2]	[3]	
10100601	84.00	05.50	03.20	[4]	[4]	
10100604	24.00	05.50	03.20	[4]	[4]	
10100701	06.57	00.43	01.20	[4]	[4]	
10100801	00.60	00.07	00.40	07.90	04.50	A
10100818	18.00	00.05	00.40	12.40	01.36	
10100902	06.80	00.19	00.09	05.70	04.90	
10102001	00.25	00.07	00.03	01.82	00.52	A
10102018	00.15	00.03	00.03	12.00	01.40	
20100101	00.46	00.06	06.62	00.60	00.60	
20100201	84.00	02.10	06.56	[4]	[4]	
20100301	35.00	02.20	06.56	[4]	[4]	

[1] Multiply ash content % (A) by the PM EF numeric value to obtain the EF.

[2] Filterable PM_{10} EF = 5.9 * (1.12 * S + 0.37), where S=sulfur content %.

[3] Filterable $PM_{2.5}$ EF = 4.3 * (1.12 * S + 0.37), where S=sulfur content %.

[4] There are no EF for these SCC because of uncertainty due to an artifact of the test method used in the past.

PM_{10} and $PM_{2.5}$ primary are calculated directly from their EF (see Table 13).

iii. Annual primary PM_{10} and $PM_{2.5}$ emissions (tons) are calculated for all but gas-fired and IGCC units by adding the filterable PM_{10} and filterable $PM_{2.5}$ emissions to condensable PM emissions. Filterable PM_{10} and $PM_{2.5}$ emissions for each unit are based on historical information regarding existing emissions controls and types of fuel burned and ash content of the fuel burned, as well as the projected emission controls (e.g., scrubbers and fabric filters). Condensable PM emissions are based on plant type, sulfur content of the fuel, and SO_2/HCl and PM control configurations. Although EPA's analysis is based on the best available emission factors, these emission factors do not account for the potential changes in condensable PM emissions due to the installation and operation of SCRs. The formation of additional condensable PM (in the form of SO_3 and H_2SO_4) in units with SCRs depends on a number of factors, including coal sulfur content, combustion conditions and characteristics of the catalyst used in the SCR, and is likely to vary widely from unit to unit. SCRs are generally designed and operated to minimize increases in condensable PM. This limitation means that condensable PM emissions are potentially underestimated for units with SCRs. In contrast, it is possible condensable PM emissions are overestimated in a case where the unit is combusting a low-sulfur coal in the presence of a scrubber.

$$Annual\ Emission_{Primary\ PM_{10}}\ (tons) =$$

$$\left(Annual\ Emission_{Filterable\ PM_{10}}\ (tons) + Annual\ Emission_{PM\ Condensable}(tons)\right)$$

$$Annual\ Emission_{Primary\ PM_{2.5}}\ (tons) =$$

$$\left(Annual\ Emission_{Filterable\ PM_{2.5}}\ (tons) + Annual\ Emission_{PM\ Condensable}(tons)\right)$$

Where:

$$Annual\ Emission_{Filterable\ PM_{10}}\ (tons) =$$

$$\left(\frac{Fuel\ Use\ (ton, k-gallon, MMcf) * Emission\ Factor_{Filterable\ PM_{10}}\ (lb/ton, k-gallon, MMcf)}{2000\ (lb/ton)}\right)$$

$$*\left(1-\frac{Filterable\ Control\ Efficiency_{PM_{10}}}{100}\right)\ *\ \left(Ash\ Content\ (\%)\right)$$

$$Annual\ Emission_{Filterable\ PM_{2.5}}\ (tons) =$$

$$\left(\frac{Fuel\ Use\ (ton, k-gallon, MMcf) * Emission\ Factor_{FilterablePM_{2.5}}\ (lb/ton, k-gallon, MMcf)}{2000\ (lb/ton)}\right)$$

$$*\left(1-\frac{Filterable\ Control\ Efficiency_{PM_{2.5}}}{100}\right)\ *\left(Ash\ Content\ (\%)\right)$$

If $Annual\ Emission_{Filterable\ PM_{2.5}}\ (tons)$ is greater than $Annual\ Emission_{Filterable\ PM_{10}}\ (tons)$, $Annual\ Emission_{Filterable\ PM_{2.5}}\ (tons)$ is set equal to $Annual\ Emission_{Filterable\ PM_{10}}\ (tons)$.

$$Annual\ Emission_{PM\ Condensable}\ (tons) = \frac{Annual\ Heat\ Input\ (MMBtu) * Emission\ Factor_{PM\ Condensable}\ (lb/MMBtu)}{2000\ (lb/ton)}$$

Where:

2000 converts lb to short ton and the pollutants are CO, VOC, and NH_3.

$\mathit{Filterable\ Control\ Efficiency}_{PM_{10}}$ and $\mathit{Filterable\ Control\ Efficiency}_{PM_{2.5}}$ are assigned based on a unit's ORIS code, unit ID, plant type and fuel type from the data file PMSulfurAshContent. Where PMSulfurAshContent provides no data, default values based on a unit's plant type and fuel type and coal rank as shown in Table 12 are used.[1]

Table 12: Default PM Control Efficiencies and Sulfur and Ash Contents

Plant Type	Fuel Type / Coal Rank	Filterable PM_{10} Control Efficiency (%)	Filterable $PM_{2.5}$ Control Efficiency (%)	Sulfur Content (%)	Ash Content (%)
Biomass	Biomass	99.2	99.2	1.67	10.8
Coal Steam	Bituminous	99.2	99.2	1.67	10.8
Coal Steam	Subbituminous	99.2	99.2	0.32	05.6
Coal Steam	Lignite	99.2	99.2	0.87	13.9
Coal Steam	Petroleum Coke	99.2	99.2	5.30	00.1
Coal Steam	Waste Coal	99.2	99.2	2.38	43.7
Coal Steam	Biomass	99.2	99.2	1.67	10.8
IGCC	Bituminous			1.67	10.8
IGCC	Subbituminous			0.32	05.6
IGCC	Lignite			0.87	13.9
IGCC	Petroleum Coke			5.30	00.1
O/G Steam	Oil	99.2	99.2	0.89	00.0
O/G Steam	Orimulsion	99.2	99.2	0.89	00.0
Combustion Turbine	Oil			0.11	00.0
Combined Cycle	Oil			0.11	00.0

$SO_2\ \mathit{Content}\ (lb/MMBtu)\ \mathit{and}\ \mathit{Ash\ Content}\ (lb/MMBtu)$ are assigned using EPA Base Case v.5.14 assumptions. The EPA Base Case v.5.14 SO_2 and ash contents are in lb/MMBtu and converted into percentage-of-fuel sulfur and ash contents as follows:

i. Sulfur content conversion

If fuel type is coal, waste coal or petroleum coke:

$$\mathit{Sulfur\ Content}\ (\%) =$$

$$\frac{SO_2\ \mathit{Content}\ (lb/MMBtu) * \mathit{Heat\ Content}\ (MMBtu/ton)}{2 * 2000\ (lb/ton)} * 100$$

[1] For units with existing ESPs but still not able to meet their MATS filterable PM requirement, unit-specific filterable PM incremental reductions needed to meet the requirement are incorporated into the units' $\mathit{Filterable\ Control\ Efficiency}_{PM_{10}}$ and $\mathit{Filterable\ Control\ Efficiency}_{PM_{2.5}}$. For information on the unit-specific incremental filterable PM reductions needed and incorporated here, see Document for EPA Base Case v.5.14 Using Integrated Planning Model, Chapter 5, Section 5.6.1.

where 2000 converts lb to short ton.

If fuel type is oil:

$$Sulfur\ Content\ (\%) =$$

$$\frac{SO_2\ Content\ (lb/MMBtu) * Heat\ Content\ (MMBtu/k-gallon)}{2 * 7882\ (lb/k-gallon)} * 100$$

where 7882 converts lb to k-gallon of oil.

If fuel type is fossil waste and the unit uses process gas SCC “101007”:

$$Sulfur\ Content\ (\%) =$$

$$\frac{SO_2\ Content\ (lb/MMBtu) * Heat\ Content\ (MMBtu/MMcf)}{2 * 52794\ (lb/MMcf)} * 100$$

where 52794 converts lb to MMcf of fossil waste[2].

If fuel type is fossil waste and the unit uses natural gas SCC "201002":

$$Sulfur\ Content\ (\%) =$$

$$\frac{SO_2\ Content\ (lb/MMBtu) * Heat\ Content\ (MMBtu/MMcf)}{2 * 44000\ (lb/MMcf)} * 100$$

where 44000 converts lb to MMcf of natural gas.

No sulfur content conversion is performed for natural gas as the sulfur content for natural gas is assumed to be zero.

ii. Ash content conversion for coal

$$Ash\ Content\ (\%) =$$

$$\frac{Ash\ Content\ (lb/MMBtu) * Heat\ Content\ (MMBtu/ton)}{2000} * 100$$

where 2000 is the number of lb per short ton.

If no sulfur and ash content assumptions from EPA Base Case v.5.14 are available, default values based on a unit’s ORIS code, unit ID, plant type and fuel type from the data file PMSulfurAshContent are used first; default values based on plant type and coal rank in Table 12 are used second. This hierarchy is summarized in Flow Chart 5.

[2] Fossil waste using process gas SCC is assumed to be a combination of coke-oven gas and blast-furnace gas.

Flow Chart 5. Sulfur and Ash Contents Assignment Hierarchy

1. EPA Base Case v.5.14 SO_2 and ash content (lb/MMBtu) assumptions, converted into percentage-of-fuel sulfur and ash contents

↓

2. Default percentage-of-fuel sulfur and ash contents by ORIS code, unit ID, plant type and fuel type

↓

3. Default percentage-of-fuel sulfur and ash contents by plant type and fuel rank

$Emission\ Factor_{PM\ Condensable}\ (lb/MMBtu)$ is assigned for all units based on units' SCCs and whether they have either an SO_2 control or PM scrubber installed as shown in Table 13.

Table 13: SCC-Based PM Condensable Emission Factors (lbs/MMBtu)

SCC	SO_2 Control[1]	PM Control[1]	PM Condensable EF[2]
10100201	Wet Scrubber	PM Scrubber	0.0200
10100201	Dry Scrubber	PM Scrubber	0.0200
10100202	Wet Scrubber	PM Scrubber	0.0200
10100202	Dry Scrubber	PM Scrubber	0.0200
10100203	Wet Scrubber	PM Scrubber	0.0200
10100203	Dry Scrubber	PM Scrubber	0.0200
10100204			0.0400
10100211	Wet Scrubber	PM Scrubber	0.0200
10100211	Dry Scrubber	PM Scrubber	0.0200
10100212	Wet Scrubber	PM Scrubber	0.0200
10100212	Dry Scrubber	PM Scrubber	0.0200
10100215	Wet Scrubber	PM Scrubber	0.0200
10100215	Dry Scrubber	PM Scrubber	0.0200
10100218			0.0100
10100221	Wet Scrubber	PM Scrubber	0.0200
10100221	Dry Scrubber	PM Scrubber	0.0200
10100222	Wet Scrubber	PM Scrubber	0.0200
10100222	Dry Scrubber	PM Scrubber	0.0200
10100223	Wet Scrubber	PM Scrubber	0.0200
10100223	Dry Scrubber	PM Scrubber	0.0200
10100224			0.0400
10100226	Wet Scrubber	PM Scrubber	0.0200
10100226	Dry Scrubber	PM Scrubber	0.0200
10100235	Wet Scrubber	PM Scrubber	0.0200

SCC	SO_2 Control[1]	PM Control[1]	PM Condensable EF[2]
10100235	Dry Scrubber	PM Scrubber	0.0200
10100238			0.0100
10100301	Wet Scrubber	PM Scrubber	0.0200
10100301	Dry Scrubber	PM Scrubber	0.0200
10100302	Wet Scrubber	PM Scrubber	0.0200
10100302	Dry Scrubber	PM Scrubber	0.0200
10100303	Wet Scrubber	PM Scrubber	0.0200
10100303	Dry Scrubber	PM Scrubber	0.0200
10100306			0.0400
10100318			0.0100
10100401			0.0100
10100404			0.0100
10100409			0.0100
10100801			0.0100
10100818			0.0100
10100902			0.0170
10102001	Wet Scrubber	PM Scrubber	0.0200
10102001	Dry Scrubber	PM Scrubber	0.0200
10102018			0.0100
20100101			0.0072

[1] For the given SCC, only one of the controls need be present for the EF to be assigned.

[2] For SCCs that have non-blank controls for both SO_2 and PM, then EF = (0.1 * S) - 0.03, (where S=sulfur content %), but if the EF is less than 0.01, set it equal to 0.01.

For the SCCs in Table 13 that have non-blank controls for both SO_2 and PM, their PM condensable emission factor can be calculated using the equation below:

$$PM\ Condensable\ Emission\ Factor = \left(0.1 * Sulfur\ Content\ (\%)\right) - 0.03$$

If the calculated value is less than the floor of 0.01 lb/MMBtu, then 0.01 is assigned as the PM condensable Emission Factor in place of the calculated value.

Also, units having an SO_2 control are assigned the lower of the PM condensable emission factor from Table 13 and the calculated PM condensable emission factor using the above equation.

Primary PM_{10} and primary $PM_{2.5}$ cannot be estimated for gas-fired units (including IGCCs) using the same methodology as the other fuels since there are no accurate filterable emission factors for them. Thus, their emissions are estimated directly. Primary PM_{10} and primary $PM_{2.5}$ emission factors in lb/MMBtu are assigned based on each unit's SCC as shown in Table 14.

Table 14: Primary PM_{10} and Primary $PM_{2.5}$ Emission Factors for Gas-Fired and IGCC Units (lb/MMBtu)

SCC	Primary PM_{10} EF	Primary $PM_{2.5}$ EF
10100601	0.532	0.440
10100604	0.532	0.440
10100701	0.043	0.035
20100201	0.317	0.195
20100301	11.263	11.263

2. Seasonal emission calculations:

Summer is considered to be the 153 days between May 1 and September 30 inclusive. Summer NO_x emissions are taken directly from IPM run results. For all other pollutants, summer emissions are calculated by multiplying the annual emissions by the ratio of the summer to annual heat input.

$$Summer\ Emissions\ (tons) = Annual\ Emissions\ (tons) * \left(\frac{Summer\ Heat\ Input\ (MMBtu)}{Annual\ Heat\ Input\ (MMBtu} \right)$$

Winter is considered to be the 212 days between October 1 and April 30 inclusive that are not considered to be summer days. Winter emissions are calculated by subtracting the summer emissions from the annual emissions.

$$Winter\ Emissions\ (tons) = Annual\ Emissions\ (tons) - Summer\ Emissions\ (tons)$$

3. Monthly emission calculations:

Summer monthly emissions for are calculated as follows:

$$Summer\ Monthly\ Emissions\ (tons) = \frac{Summer\ Emissions\ (tons)}{153} * Number\ of\ \ Day\ in\ Month$$

Winter monthly emissions are calculated as follows:

$$Winter\ Monthly\ Emissions\ (tons) = \frac{Winter\ Emissions\ (tons)}{212} * Number\ of\ \ Day\ in\ Month$$

SECTION IV: FLAT FILE LAYOUT

The processed data are then converted into a flat file for U.S. EPA to use in air quality modeling work. Both criteria and HAP emissions are provided in the same file. The pollutants are provided in the following order: CO, NO_x, VOC, SO_2, NH_3, primary PM_{10}, primary $PM_{2.5}$, Mercury (Hg), and HCl.

The file's naming convention is as follows:

FlatFile_<ipm run alpha-numeric only>_<year4>_<date created using yyyymmdd>.txt

where:

year4 = 4-digit year of the emissions (e.g., 2030)
yyyy = 4-digit year
mm = 2-digit month number (e.g. 01 through 12)
dd = 2-digit date number (e.g., 01 through 31)

For example: 'FlatFile_EPA513_BC_7c_2018_20131108.txt'.

All data fields are comma-delimited and character data, including commas, semi-colons, and spaces, are enclosed in double-quotes.

The file contains the following header lines:

#FORMAT=ff10_POINT
#COUNTRY=US
#YEAR=<year of emissions>
#VALUE_UNITS=TON
#CREATION_DATE=<date created>
#CREATOR_NAME=US EPA-CAMD
#DATA_SET_ID=1,US EPA IPM
#COUNTRY_CD,REGION_CD,TRIBAL_CODE,EIS_FACILITY_ID,EIS_UNIT_ID,EIS_REL_POINT_ID,EIS_PROCESS_ID,AGY_FACILITY_ID,AGY_UNIT_ID,AGY_REL_POINT_ID,AGY_PROCESS_ID,SCC,POLL,ANN_VALUE,ANN_PCT_RED,FACILITY_NAME,ERPTYPE,STKHGT,STKDIAM,STKTEMP,STKFLOW,STKVEL,NAICS,LONGITUDE,LATITUDE,LL_DATUM,HORIZ_COLL_MTHD,DESIGN_CAPACITY,DESIGN_CAPACITY_UNITS,REG_CODES,FAC_SOURCE_TYPE,UNIT_TYPE_CODE,CONTROL_IDS,CONTROL_MEASURES,CURRENT_COST,CUMULATIVE_COST,PROJECTION_FACTOR,SUBMITTER_FAC_ID,CALC_METHOD,DATA_SET_ID,FACIL_CATEGORY_CODE,ORIS_FACILITY_CODE,ORIS_BOILER_ID,IPM_YN,CALC_YEAR,DATE_UPDATED,FUG_HEIGHT,FUG_WIDTH_YDIM,FUG_LENGTH_XDIM,FUG_ANGLE,ZIPCODE,ANNUAL_AVG_HOURS_PER_YEAR,JAN_VALUE,FEB_VALUE,MAR_VALUE,APR_VALUE,MAY_VALUE,JUN_VALUE,JUL_VALUE,AUG_VALUE,SEP_VALUE,OCT_VALUE,NOV_VALUE,DEC_VALUE,JAN_PCTRED,FEB_PCTRED,MAR_PCTRED,APR_PCTRED,MAY_PCTRED,JUN_PCTRED,JUL_PCTRED,AUG_PCTRED,SEP_PCTRED,OCT_PCTRED,NOV_PCTRED,DEC_PCTRED,COMMENT

The last header line contains comma-delimited field names identifying the data contained in each data field.

Appendix A
Default Values

Field Name	Default Value
COUNTRY_CD	N/A
REGION_CD	N/A
TRIBAL_CODE	N/A
EIS_FACILITY_ID	"ORIS" followed by the ORIS_FACILITY_CODE. For example, ORIS55177.
EIS_UNIT_ID	"ORIS" followed by the ORIS_BOILER_ID. For example, ORISST1.
EIS_REL_POINT_ID	"ORIS" followed by the ORIS_BOILER_ID. That is, the same as the unit ID default value.
EIS_PROCESS_ID	Use the same value as in the [IPM Y/N] field. That is, the NEEDS UniqueID.
AGY_FACILITY_ID	Blank
AGY_UNIT_ID	Blank
AGY_REL_POINT_ID	Blank
AGY_PROCESS_ID	Blank
SCC	N/A
POLL	N/A
ANN_VALUE	N/A
ANN_PCT_RED	Blank
FACILITY_NAME	NEEDS Plant Name
ERPTYPE	Blank
STKHGT	SCC-based default stack parameters from SCCDefaultStackParameters file.
STKDIAM	SCC-based default stack parameters from SCCDefaultStackParameters file.
STKTEMP	SCC-based default stack parameters from SCCDefaultStackParameters file.
STKFLOW	SCC-based default stack parameters from SCCDefaultStackParameters file.
STKVEL	SCC-based default stack parameters from SCCDefaultStackParameters file.
NAICS	Blank
LONGITUDE	County-centroid based longitude by ORIS code, state FIPS code and country FIPS code from LatLonDefault file.
LATITUDE	County-centroid based longitude by ORIS code, state FIPS code and country FIPS code from LatLonDefault file.
LL_DATUM	Blank
HORIZ_COLL_MTHD	Blank
DESIGN_CAPACITY	N/A
DESIGN_CAPACITY_UNITS	N/A
REG_CODES	Blank
FAC_SOURCE_TYPE	"125"
UNIT_TYPE_CODE	"100" for Boiler, "120" for Turbine, "140" for combined cycle (boiler/gas turbine).

Field Name	Default Value
CONTROL_IDS	N/A
CONTROL_MEASURES	Blank
CURRENT_COST	Blank
CUMULATIVE_COST	Blank
PROJECTION_FACTOR	Blank
SUBMITTER_ID	N/A
CALC_METHOD	N/A
DATA_SET_ID	N/A
FACIL_CATEGORY_CODE	N/A
ORIS_FACILITY_CODE	NEEDS ORIS Code
ORIS_BOILER_ID	NEEDS Unit ID
IPM_YN	N/A
INV_YEAR	N/A
DATE_UPDATED	N/A
FUG_HEIGHT	Blank
FUG_WIDTH_YDIM	Blank
FUG_LENGTH_XDIM	Blank
FUG_ANGLE	Blank
ZIPCODE	N/A
ANNUAL_AVG_HOURS_PER_YEAR	N/A
JAN_VALUE	N/A
FEB_VALUE	N/A
MAR_VALUE	N/A
APR_VALUE	N/A
MAY_VALUE	N/A
JUN_VALUE	N/A
JUL_VALUE	N/A
AUG_VALUE	N/A
SEP_VALUE	N/A
OCT_VALUE	N/A
NOV_VALUE	N/A
DEC_VALUE	N/A
JAN_PCTRED	Blank
FEB_PCTRED	Blank
MAR_PCTRED	Blank
APR_PCTRED	Blank
MAY_PCTRED	Blank
JUN_PCTRED	Blank
JUL_PCTRED	Blank
AUG_PCTRED	Blank
SEP_PCTRED	Blank

Field Name	Default Value
OCT_PCTRED	Blank
NOV_PCTRED	Blank
DEC_PCTRED	Blank
COMMENT	Blank

Appendix B
Temporal Allocation of IPM Projected Seasonal Emissions to Hourly Emissions for Use in Air Quality Modeling

IPM provides unit-level emission projections of average winter (representing October through April) and average summer (representing May through September) values. To use these data in an air quality model, the unit-level data must first be converted to into hourly values through a process called "temporal allocation".

The goal of the temporal allocation process is to reflect the variability in the unit-level emissions that can impact air quality over seasonal, daily, or hourly time scales, in a manner compatible with incorporating future-year emission projections into future-year air quality modeling. The temporal allocation process is applied to the seasonal emission projections obtained from an IPM modeling scenario. IPM represents two seasons: summer (May through September) and winter (October through April). IPM unit-level parsed files contain seasonal and annual totals of SO_2, NO_X, CO_2, Hg, and HCl emissions (computed directly within IPM), while $PM_{2.5}$, PM_{10}, VOC, NH_3, and CO emissions are calculated using a post-processing tool[3] based on each unit's projected fuel use and configuration, coupled with pollutant-specific emission factors.[4] When calculating PM emissions, the post-processing tool utilizes specific data assumptions such as the ash and sulfur content of the coal projected to be used at the unit. The tool creates a Flat File (in a comma-separated value or .csv file format) that provides the starting point for developing emission inputs to an air quality model.

The resulting Flat File contains all of the endogenously-determined and post-calculated unit-level emissions combined with stack parameters (i.e., stack location and other characteristics consistent with information found in the National Emissions Inventory (NEI)). A cross reference is used to map the units in NEEDS to the stack parameter and facility, unit, release point, and process identifiers used in the National Emissions Inventory (NEI). The cross reference also maps sources to the hourly Continuous Emissions Monitoring System (CEMS) data that is used to temporally allocate the emissions in the base year air quality modeling. This cross reference has been updated for the v5.14 platform through collaboration with EPA, regional planning organizations, and states and is also used to determine which emissions sources in the NEI sources have future year emissions predicted by IPM. Emissions from point sources for which emissions are not predicted by IPM are carried forward into the future year modeling platform using other projection methods. Therefore, if the NEI and IPM sources are not properly matched, double-counting could result because the future year emissions output from IPM in the future year are treated as a full replacement for the base year emissions, although only for the emissions processes estimated by IPM.

In order to support the temporal allocation process and other requirements of modeling point sources, the Flat File output from the IPM postprocessor specifies annual and monthly emissions for each stack; however, since IPM projections are only modeled for two seasons comprising multiple months each, monthly emissions cannot be precisely specified in the Flat File. Instead, the monthly values in the Flat File output from the postprocessor are computed by multiplying the average summer day and average winter day emissions predicted by IPM by the number of days in the respective month. In summary, the monthly emission values shown in the Flat File are not intended to represent an actual month-to-month emission pattern; instead, they are interim values that have translated IPM's seasonal projections into month-level data that serve as a starting point for the temporal allocation process.

The monthly emissions within the Flat File undergo a multi-step temporal allocation process to yield the hourly emission values at each unit, as is needed for air quality modeling: summer/winter value to month, month to day, and day to hour. For sources not matched to unit-specific CEMS data, the first two steps are done outside of SMOKE and the third step to get to hourly values is done by SMOKE using daily the emissions files created from the first two steps. For each of these three temporal allocation steps, NO_x and SO_2 CEMS data are used to allocate NO_x and SO_2 emissions, while CEMS heat input data are used to allocate all other pollutants. The approach defined here gives priority to temporalization based on the base year CEMS data to the maximum extent possible.

[3] Documentation of this tool can be found at www.epa.gov/powersectormodeling
[4] For more information on EPA emission factors see http://www.epa.gov/ttnchie1/ap42/

Prior to using the 2011 CEMS data to develop monthly, daily, and hourly profiles, the CEMS data was processed through a tool that found data quality flags that indicated the data were measured. These situations can cause erroneously high values in the CEMS data. If the data were not measured, and it was found to be more the 3 times the annual mean, the data were replaced with annual mean values. These adjusted CEMS data were used to compute the monthly, daily, and hourly profiles described above (see example in Figure B-1).

For units in NEEDS that are matched to units in the National Emission Inventory (NEI), and for which CEMS data are available, the emissions are temporalized based on the CEMS data for that unit and pollutant. For units that are not matched to the NEI or for which CEMS data are not available, the allocation of the IPM seasonal emissions to months is done using average fuel-specific season-to-month factors generated for each of the 64 IPM regions shown in Figure B-2. These factors are based on a single year of CEMS data for the modeling base year associated with the air quality modeling analysis being performed, such as 2011. Note that IPM uses load data (reflecting the shape of demand) corresponding to the load in each IPM region that occurred in the base year of the air quality modeling analysis, such as 2011. The fuels used for creating the profiles for a region are coal, natural gas, and other, where the other fuels used include oil and wood and vary by region. Separate profiles are computed for NO_x, SO_2, and heat input. An overall composite profile across all fuels is also computed and can be used in the event that a region has too few units of a fuel type to make a reasonable average profile, or in the case when a unit changes fuels between the base and future year and there were previously no units with that fuel in the region containing the unit.

The monthly emission values in the Flat File are first reallocated across the months in that season to align the month-to-month emission pattern at each stack with historic seasonal emission patterns.[5] While this reallocation affects the monthly pattern of each unit's future-year seasonal emissions, the seasonal totals are held equal to the IPM projection for that unit and season. Second, the reallocated monthly emission values at each stack are disaggregated down to the daily level consistent with historic daily emission patterns in the given month at the given stack using separate profiles for NO_x, SO_2, and heat input. This process helps to capture the influence of meteorological episodes that cause electricity demand to vary from day-to-day, as well as weekday-weekend effects that change demand during the course of a given week. Third, this data set of emission values for each day of the year at each unit is input into SMOKE, which uses temporal profiles to disaggregate the daily values into specific values for each hour of the year.

For units without or not matched to CEMS data, or for which the CEMS data are found to be unsuitable for use in the future year, emissions are allocated from month to day using IPM-region and fuel-specific average month-to-day factors based on CEMS data from the base year of the air quality modeling analysis. These instances include units that did not operate in the base year or for which it may not have been possible to match the unit in NEEDS with a specific unit in the NEI. EPA uses average emission profiles for some units with CEMS data in the base year when one of the following cases is true: (1) units are projected to have substantially increased emissions in the future year compared to its emissions in the base (historic) year[6]; (2) CEMS data are only available for a limited number of hours in that base year; (3) units change fuels in the future year; (4) the unit is new in the future year; or (5) units experienced atypical conditions during the base year, such as lengthy downtimes for maintenance or installation of controls. The temporal profiles that map emissions from days to hours are computed based on the region and fuel-specific seasonal (i.e., winter and summer) average day-to-hour factors derived from the CEMS data for those fuels and regions using only heat input data for that season. Only heat inpt is used because it is the variable that is the most complete in the CEMS data. SMOKE uses these profiles to allocate the daily emissions data to hours.

The emissions from units for which unit-specific profiles are not deemed appropriate, and for units in the IPM outputs that are not specifically matched to units in the base year, are temporally allocated to hours reflecting

[5] For example, the total emissions for a unit in May would not typically be the same as the total emissions for the same unit in July, even though May and July are both in the summer season and the number of days in those months is the same. This is because the weather changes over the course of each season, and thus the operating behavior of a specific unit can also vary throughout each season. Therefore, part of the temporal allocation process is intended to create month-specific emissions totals that reflect this intra-seasonal variation in unit operation and associated emissions.

[6] In such instances, EPA does not use that unit's CEMS data for temporal allocation in order to avoid assigning large increases in emissions over short time periods in the unit's hourly emission profile.

patterns typical of the region in which the unit is located. Analysis of CEMS data for units in each of the 64 IPM regions revealed that there were differences in the temporal patterns of historic emission data that correlate with fuel type (e.g., coal, gas, and other), time of year, pollutant, season (i.e. winter versus summer) and region of the country. The correlation of the temporal pattern with fuel type is explained by the relationship of units' operating practices with the fuel burned. For example, coal units take longer to ramp up and ramp down than natural gas units, and some oil units are used only when electricity demand cannot otherwise be met. Geographically, the patterns were less dependent on state location than they were on IPM regional location. For temporal allocation of emissions at these units, Figure B-3 provides an example of daily coal, gas, and composite profiles in one IPM region. EPA developed seasonal average emission profiles, each derived from base year CEMS data for each season across all units sharing both IPM region and fuel type.[7] Figure B-4 provides an example of seasonal profiles that allocate daily emissions to hours in one IPM region. These average day to hour temporal profiles were also used for sources during seasons of the year for which there were no CEMS data available, but for which IPM predicted emissions in that season. This situation can occur for multiple reasons, including how the CEMS was run at each source in the base year.

For units that do have CEMS data in the base year and are matched to units in the IPM output, the base year CEMS data are scaled so that their seasonal emissions match the IPM-projected totals. In particular, the fraction of the unit's seasonal emissions in the base year is computed for each hour of the season, and then applied to the seasonal emissions in the future year. This is accomplished outside of SMOKE by creating data in the same format as CEMS data for NOx, SO2, and heat input. Any pollutants other than NOX and SO2 are temporalized within SMOKE using heat input as a surrogate. Distinct factors are used for the fuels coal, natural gas, and "other". This procedure yields future-year hourly data that have the same temporal pattern as the base year CEMS data while matching future-year seasonal total emissions for each stack to IPM's future-year projections (see example in Figure B-5).

In cases when the emissions for a particular unit are projected to be substantially higher in the future year than in the base year, the proportional scaling method to match the emission patterns in the base year described above can yield emissions for a unit that are much higher than the historic maximum emissions for that unit. To address this issue for the 2017 scenario, the maximum measured emissions of NO_x and SO_2 in the period of 2011-2014 were computed. The temporalized emissions were then evaluated at each hour to determine whether they were above this cumulative maximum. The amount of "excess emissions" over the maximum was then computed. For units for which the "excess emissions" could be reallocated to other hours, those emissions were distributed evenly to hours that were below the maximum. Those hourly emissions were then reevaluated against the maximum, and the procedure of reallocating the excess emissions to other hours was repeated until all of the hours had emissions below the maximum, whenever possible (see example in Figure B-6).

Using the above approach, it was not always possible to reallocate excess emissions to hours below the historic maximum, such as when the total seasonal emissions of NOx or SO2 for a unit divided by the number of hours of operation are greater than the 2011-2014 maximum emissions level. For these units, the *regional* fuel-specific average profile was applied to all pollutants, including heat input, for that season (see example in Figure B-7). An exception to this is if the fuel for that unit is not gas or coal. In that case, the composite (non-fuel-specific) profile was used for that unit. This is because many sources that used "other" fuel profiles had very irregular shapes due to a small number of sources in the region, and the allocated emissions frequently still exceeded the 2011-2014 maximum. Note that it was not possible for SMOKE to use regional profiles for some pollutants and adjusted CEMS data for other pollutants for the same unit / season, therefore all pollutants are assigned to regional profiles when regional profiles are needed. Also note that for some units, some hours still exceed the 2011-2014 annual maximum for the unit even after regional profiles were applied (see example in Figure B-8).

[7] EPA also uses an overall composite profile across all fuels for each IPM region in instances where a unit is projected to burn a fuel for which EPA cannot construct an average emission profile (because there were no other units in that IPM region whose historic CEMS data represent emissions from burning that fuel).

Figure B-1. Removal of Unmeasured Spikes in CEMS Data

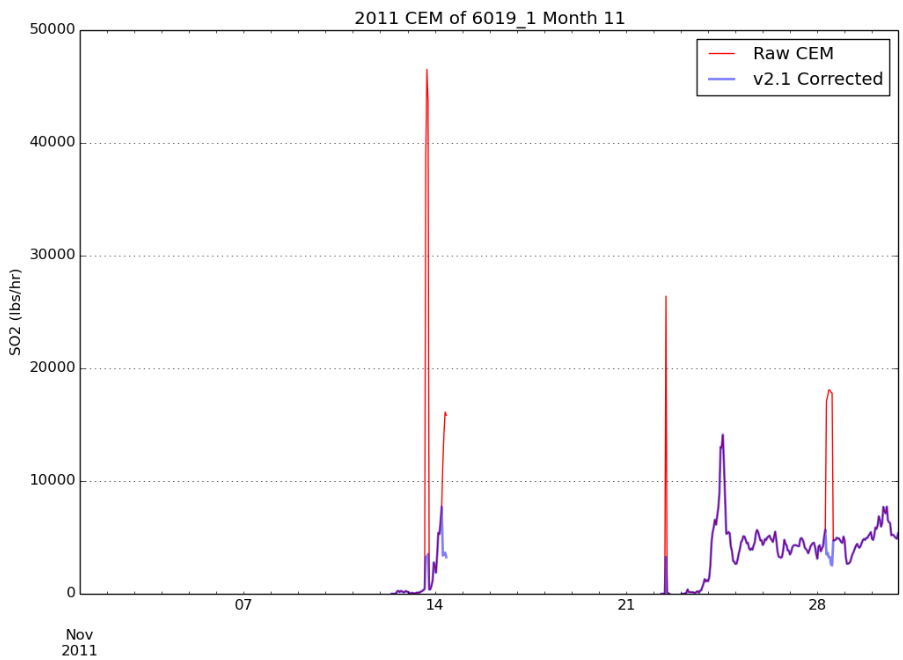


Figure B-2. EPA Base Case v.5.14 IPM Regions (64 in all)

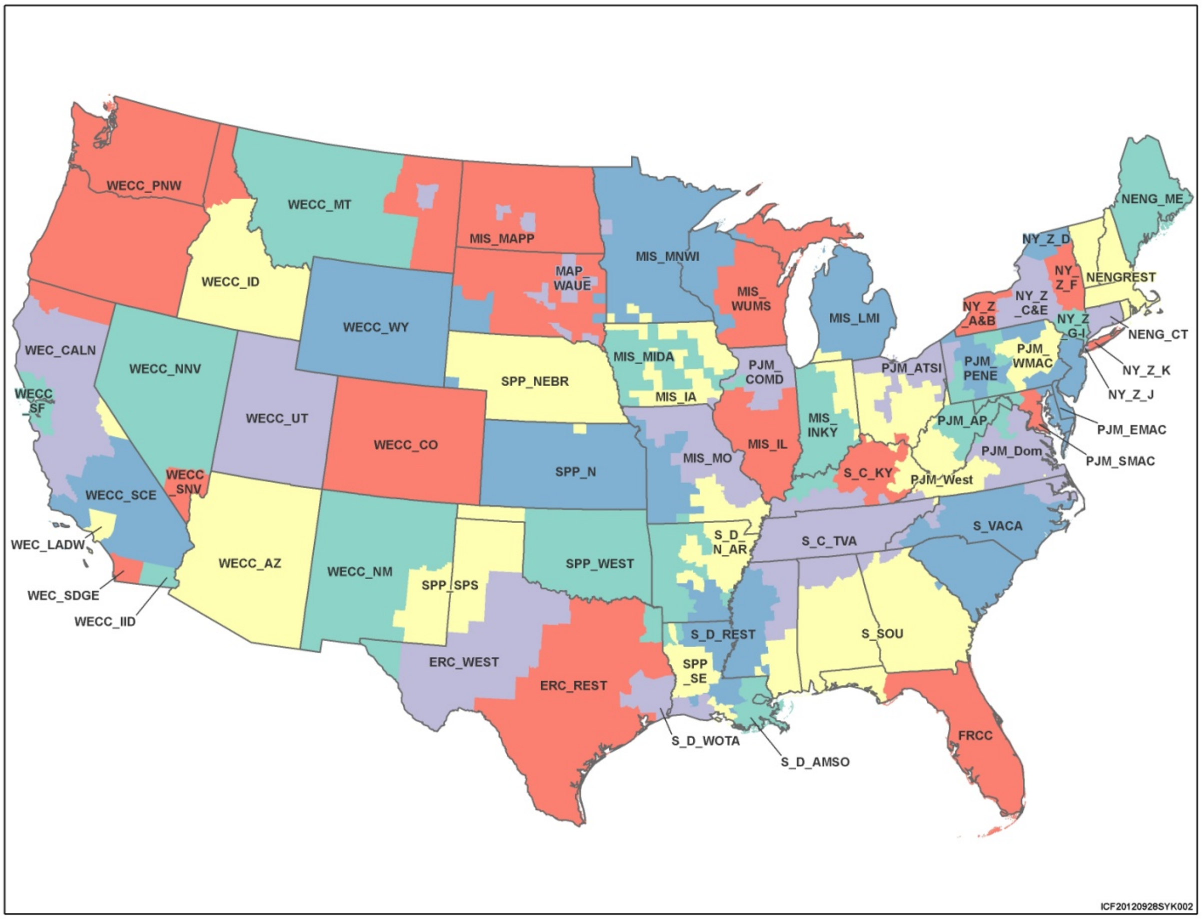


Figure B-3. Average NOx Daily Profiles by Fuel and Composite in West Texas Region (July)

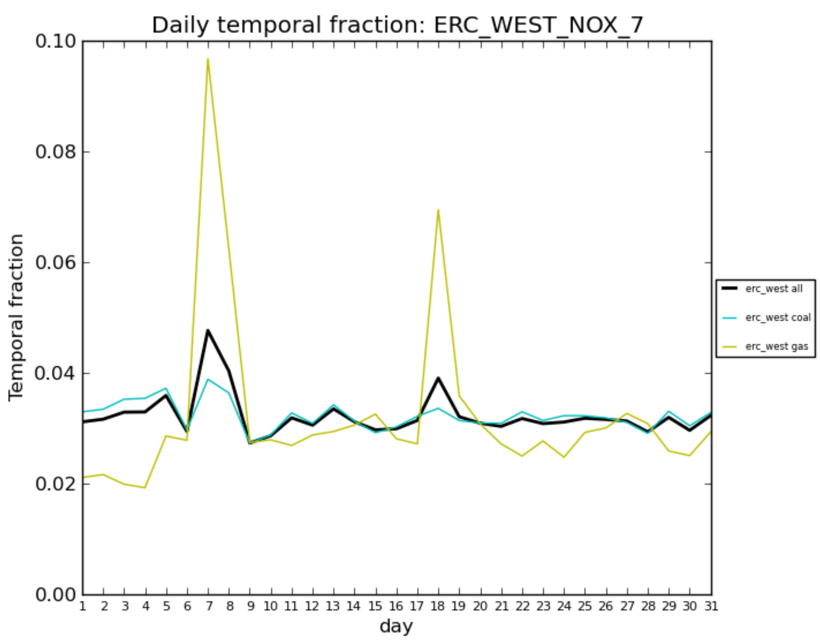


Figure B-4. Example of Summer vs. Winter Hourly Profiles in Virginia Region

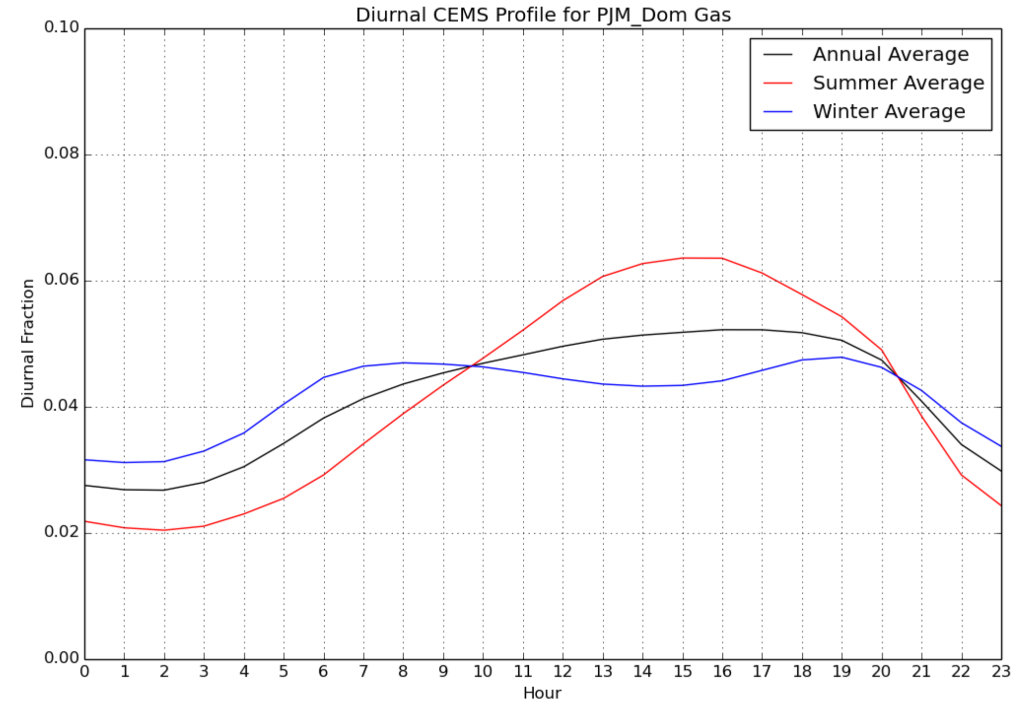


Figure B-5. Future Year Emissions Follow Pattern of Base Year Emissions

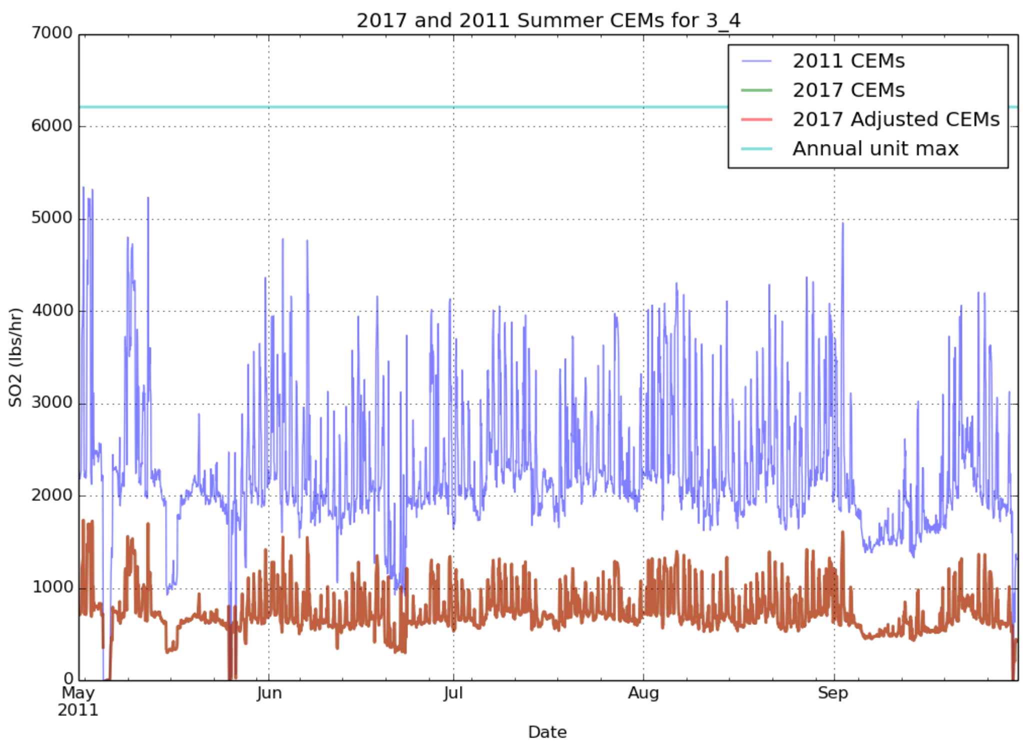


Figure B-6. Excess Emissions Apportioned to Hours Less than Maximum

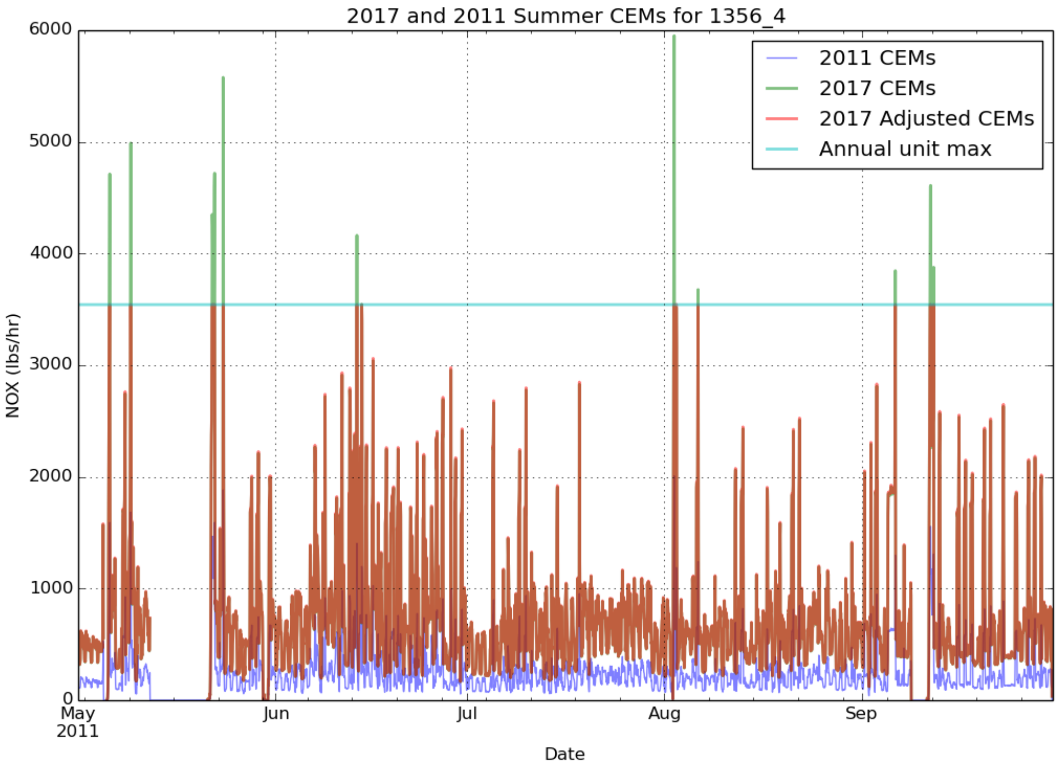


Figure B-7. Adjustment to Hours Less than Maximum not Possible, Regional Profile Applied

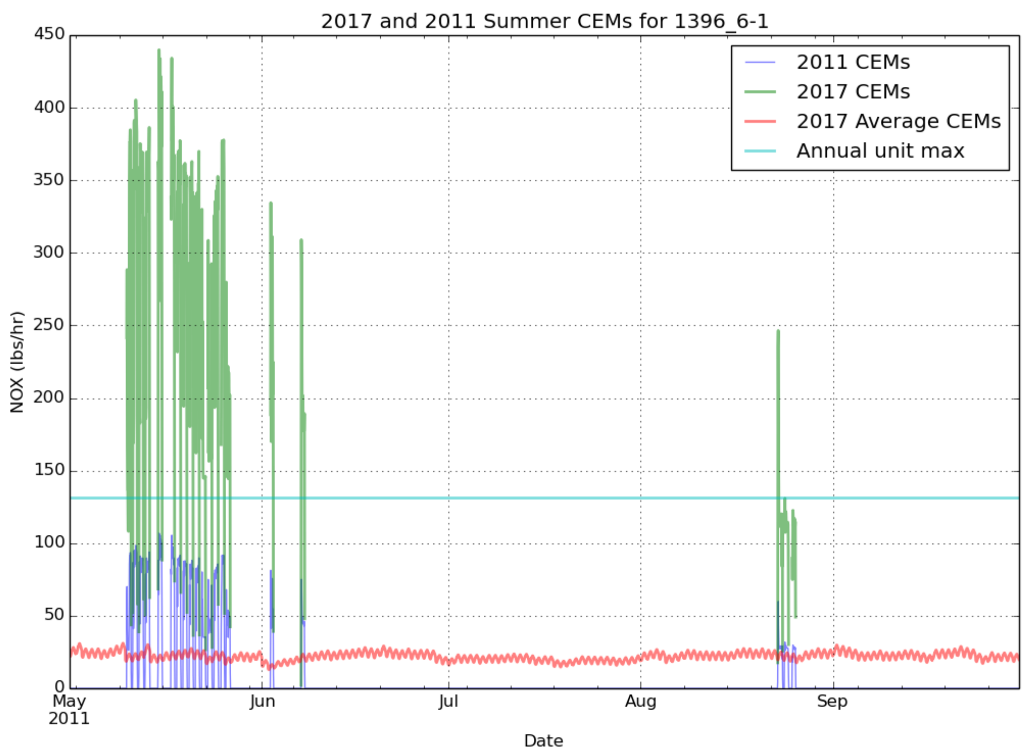


Figure B-8. Regional Profile Applied, but Exceeds Maximum in Some Hours