Air Construction Permit Application

Alabama Power Company
Barry Steam Electric Generating Plant
Unit 5 Natural Gas Conversion Project

Mobile County, Alabama

November 2025

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1.0 Introduction

Alabama Power Company (Alabama Power) owns and operates the Barry Steam Electric Generating Plant (Plant Barry) in Bucks, Alabama in Mobile County. The Alabama Department of Environmental Management (ADEM) issued Alabama Power a Title V Major Source Operating Permit for Plant Barry under Facility No. 503-1001. Plant Barry currently has three natural gas-fired steam electric generating units (Units 1, 2, and 4), one coal-fired steam electric generating unit (Unit 5), two 2-on-1 combined cycle electric generating units (Units 6A and 6B, 7A and 7B) and one 1-on-1 combined cycle electric generating unit (Unit 8).

This permit application addresses the conversion of the existing Unit 5 coal-fired steam electric generating unit to a natural gas fired-steam electric generating unit. Once converted, the unit will operate as a natural gas-fired unit with a nominal rated heat input of 7,585 mmBtu/hr, and a normal full load capacity of approximately 785 MW.

Plant Barry is an existing "major source" of criteria air pollutants, and the Project is considered a major modification under Prevention of Significant Deterioration (PSD) permitting requirements for certain regulated pollutants. Specifically, the Project is subject to PSD review under ADEM Admin. Code r. 335-3-14-.04 (ADEM 2025a) for particulate matter (PM) less than 10 microns in diameter (PM_{10}) and PM less than 2.5 microns in diameter ($PM_{2.5}$), and this document constitutes the application for an Air Permit Authorizing Construction in Clean Air Areas under the Alabama Department of Environmental Management (ADEM) Admin. Code r. 335-3-14-.04.

This application will also demonstrate that Project emissions will be less than PSD Significant Emission Rate (SER) thresholds for a major modification of volatile organic compound (VOC), and will result in no annual increase of nitrogen oxide (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), greenhouse gases (GHG), sulfuric acid mist (H_2SO_4), fluorides (F^-), or lead (Pb). Therefore, these pollutants are not subject to permitting or (for VOCs) can be permitted under chapter 335-3-14-.01 without PSD review (state Air Permit). This application and supporting analyses address the applicable permitting requirements for the Project under ADEM Admin. Code ch. 335-3-14, as well as the other reviews required by the State of Alabama, and demonstrate the Project is expected to comply with all applicable state and federal air quality regulations.

1.1 Facility Description

Alabama Power's Plant Barry is located on approximately 1,700 acres of land along the west banks of the Mobile River in Mobile County, Alabama. A facility location map is provided as **Figure 1-1**. The geographical coordinates for the approximate center of Plant Barry is:

- Universal Transverse Mercator (UTM) Easting: 403,550 meters;
- Universal Transverse Mercator (UTM) Northing: 3,430,450 meters;
- UTM Zone: 16;
- North American Datum (NAD): 1983;
- Elevation Above Mean Sea Level (AMSL): Approximately 25 feet AMSL.

In addition to the primary electric generating sources, Plant Barry also operates other smaller sources of air emissions such as an auxiliary boiler, cooling towers, and various small engines.

1.2 Project Description

Alabama Power is proposing to convert the existing Plant Barry Unit 5 coal-fired steam electric generating unit to natural gas by replacing the existing coal burners with new natural gas burners and associated equipment. The new burners will be installed at five (5) boiler elevations with eight (8) burners per elevation. Additionally, piping and valving needed to support the conversion to natural gas, and an oxidation catalyst will be installed. The installation of the new burners, the oxidation catalyst, and the associated natural gas equipment necessary for the conversion constitute the "Project" in this air permit application.

1.2.1 Project Timing

Due to the scope of work related to this Project and limitations of contractor boilermaker workforce availability, the Project will be split into multiple stages requiring two separate outages. Accordingly, the construction activities required to complete the Project will begin in October 2026 and extend through the Spring of 2028. During the first proposed planned outage in October 2026, the oxidation catalyst frame will be installed upstream of the existing Selective Catalytic Reduction (SCR) system. Between the two planned outages, onsite work to route gas supply piping, gas vent piping, on-site electrical work, and installation of a Distributed Control System (DCS) room will be completed. Lastly, a second planned outage is proposed for the Spring of 2028 and includes installation of the new natural gas burners, flue gas ductwork rerouting, gas piping connections, electrical/DCS terminations, oxidation catalyst installation, & final checkout/tuning of the boiler.

1.3 Project Location

Plant Barry is located in Mobile County, approximately 20 miles north of the City of Mobile. **Figure 1-1** is an aerial map showing the location of Plant Barry. The land use surrounding the Project consists of a mix of mostly swampland, forested areas, wetlands, water, and industrial areas. The topography surrounding Plant Barry, as indicated in the topographic map in **Figure 1-2**, is characterized by mostly flat areas with occasional gently rolling hills. A plot plan showing the plant property, adjacent roadways, and location of Unit 5 is presented in **Appendix B**.

1.4 Facility Classification

There are two major classification criteria for the proposed Project, one related to its industrial character, and the other to its potential to emit air emissions. The designation of the facility under each of these is reviewed below.

1.4.1 Standard Industrial Classification Code (SIC)

The United States government has devised a method for grouping all business activities according to their participation in the national commerce system. The system is based on classifying activities into "major groups" defined by the general character of a business operation. For example, electric, gas and sanitary services, which include power production, are defined as a major group. Each major group is given a unique two-digit number for identification. Power production activities have been assigned a major group code “49”.

To provide more detailed identification of a particular operation, an additional two-digit code is appended to the major group code. In the case of power generation facilities, the two-digit code is “11” to define the type of production involved. Thus, the proposed Project is classified under the Standard Industrial Classification (SIC) code system as:

- Major Group 49 – Electric, Gas, and Sanitary Services
- Electric Services – 4911

The North American Industrial Classification System was introduced as a replacement for SIC codes in 1997. This system's organization is similar to the SIC codes. Under this system, this facility is classified under 221112, Fossil Fuel Electric Power Generation.

1.4.2 Air Quality Source Designation

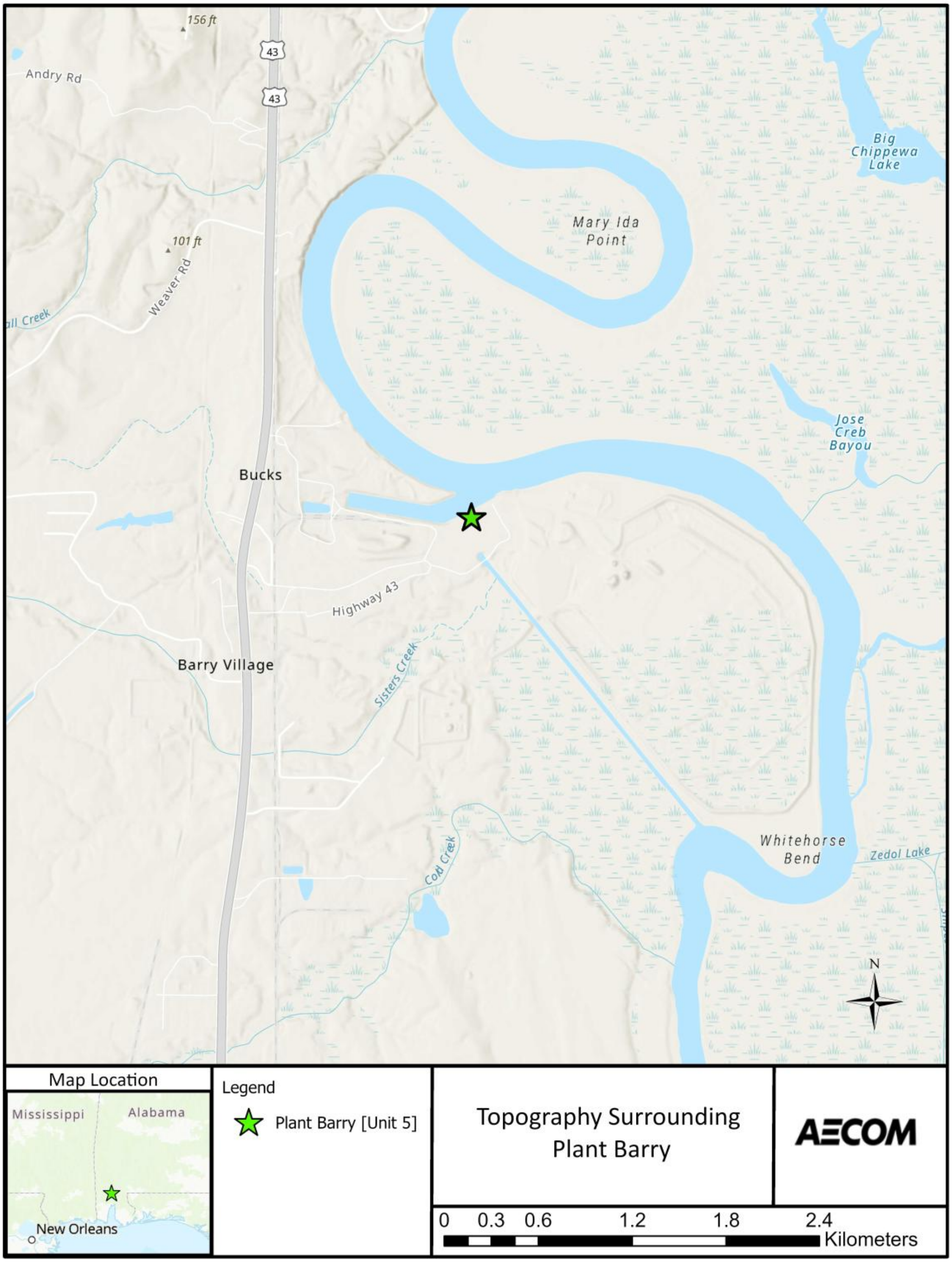
With respect to air quality, new and existing industrial sources are classified as either major or minor sources based on their potential -to -emit (PTE) air contaminants. This classification is also affected in part by whether the area in which the source is located has attained the National Ambient Air Quality Standards (NAAQS)[1]. An area is classified as unclassifiable/attainment if the ambient air quality concentration for a specific pollutant meets or is cleaner than the standard concentration level for a set of averaging periods. The area in which the proposed Project is located is designated as unclassifiable/attainment or unclassifiable for all the NAAQS in which the United States Environmental Protection Agency (US EPA) has issued a designation under Section 107 of the Clean Air Act.

For most activities, a major source is defined as one which has the PTE of 250 tons per year of any regulated air contaminant. For a certain set of 28 stationary source categories, the US EPA has defined the major source emission threshold to be 100 tons per year. Steam-Electric Power Generation is one of these groups. Plant Barry is classified as a major source. Accordingly, as discussed in this application, the proposed Project will be classified as a major modification to a “major stationary source” of air emissions for certain pollutants.

[1] Criteria pollutants are those for which US EPA has established NAAQS and consist of PM_{10}, $PM_{2.5}$, CO, NO_x, SO_2, lead, and ozone, which is formed through the photochemical reaction of VOC and NO_x in the atmosphere.

Figure 1-1. Location of Plant Barry (Aerial)

Figure 1-2. Location of Plant Barry (Topography)



1.5 Document Organization

The balance of this document is divided into sections which address each component of the PSD air quality review process. The outline below provides an overview of the contents of each of the remaining sections.

Section 2.0 – Project Emissions Summary presents a detailed review of the air emissions which are projected to occur as a result of the proposed Project.

Secton 3.0 - New Source Review Applicability (NSR) presents an analysis of NSR applicability for the proposed Project.

Section 4.0 – Requirements and Standards presents a discussion of applicable State and Federal air regulations.

Section 5.0 - Control Technology Review is a detailed evaluation of potential control technologies since the proposed Project will be classified as a major modification to a major stationary source since it is projected to result in a significant increase in the emissions of some NSR-regulated pollutants (as defined under the PSD regulations). Project emissions are projected to be significant for PM_{10} and $PM_{2.5}$ only. As such, best available control technology (BACT) analyses for these pollutants have been provided for the modified emission unit.

Section 6.0 – Class II Area Air Quality Modeling Analysis Procedures summarizes the dispersion modeling methodology and the manner in which the predicted impacts were compared to the applicable standards. Specifically, this section discusses the modeling input data and the various modeling scenarios evaluated.

Section 7.0 – Class II Area Significant Impact Level (SIL) Analysis Results presents the results of the Class II Area SIL modeling performed for the Project.

Section 8.0 – Other Requirements Potentially Applicable to Air Permits Authorizing Construction contains supplemental information regarding the potential impacts of the Project. Specifically, this section discusses the potential for impacts to Class I areas and soils and vegetation.

Section 9.0 - References will include a list of the documents relied upon during the preparation of this document.

Appendices – Appendices A, B, C, and D provide permit application forms, plot plan, emission calculations, and supporting BACT information. Additional dispersion modeling related information and supplemental materials supporting the information presented in the application are provided in Appendices E through H.

2.0 Project Emissions Summary

2.1 Introduction

With this air permit application, Alabama Power is seeking an Air Permit Authorizing Construction from ADEM for the Project at Plant Barry. As discussed previously, the Project includes the addition of natural gas burners, an oxidation catalyst, associated piping, valving, and instrumentation required to convert Plant Barry Unit 5 to a natural gas-fired electric generating unit.

In this section, a summary of the Project emissions calculations are shown, the source of emissions factors are identified, and assumptions are discussed.

2.2 Fuel Types

Following conversion, Barry Unit 5 will fire natural gas only. The heating value of natural gas is projected to average approximately 1020 British thermal units per standard cubic foot (Btu/scf). The fuel type is also listed on the enclosed ADEM Form 104.

2.3 Emission Rates

Emissions for the project are estimated using emission factors from US EPA's *AP-42, Fifth Edition, Compilation of Air Pollutant Emission Factors Volume I, Stationary Point and Area Sources, Chapter 1 External Combustion Sources, Section 1.4 Natural Gas Combustion* (e.g. AP-42), from emission factor methodologies in US EPA's Mandatory Greenhouse Gas Reporting Rule (GHGRR) in 40 CFR Part 98, from other sources of published data, and from engineering estimates.

The vendor provided engineering estimates for NO_X, CO, and VOC emission rates from natural gas operations. Emission rates for SO_2, PM, and lead were obtained from AP-42. Hazardous air pollutant (HAP) emissions for which an emission factor is available from AP-42 have also been calculated. There are no emission factors for fluorides, hydrogen sulfide, total reduced sulfur or reduced sulfur compounds for natural gas combustion in AP-42. Therefore, the emissions of these pollutants are assumed to be zero or negligible for this Project.

2.4 Future Projected Actual Emissions

As discussed in Section 1.2, the Project will be implemented on Unit 5 at Plant Barry – an existing major stationary source. As such, the "actual-to-projected-actual applicability test for projects that only involve existing emissions units" identified in ADEM Admin. Code r. 335-3-14-.04(1)(f) is utilized in the PSD applicability determination. As part of this analysis, the future projected actual annual emission rates (as defined in ADEM Admin. Code r. 335-3-14-.04(2)(nn) in tons per year) were calculated for regulated NSR pollutants as discussed below.

A summary of the Project's emission rates, emission factors, and projected actual annual emissions for NSR pollutants and GHGs calculated as carbon dioxide equivalent (CO_2e) are provided in **Table 2-1**. Calculations utilize the nominal maximum rated heat input which results in the highest mass emission rates on gas operations for all pollutants.

All PM (total, condensable and filterable) emissions are conservatively assumed to be $PM_{2.5}$. "Total PM" emissions include only filterable PM; however, PM_{10} and $PM_{2.5}$ emissions include both filterable and condensable particulate matter. Emissions of sulfuric acid mist (H_2SO_4) due to the Project are calculated using the methodologies outlined in Electric Power Research Institute's "*Estimating Total Sulfuric Acid Emissions from Stationary Power Plants*," publication dated 2018.

Emissions of GHGs from natural gas combustion are composed of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The emission factors for these three gases are reported as CO_2 equivalent (CO_2e). The emission factors utilized for GHGs in this application are derived from methodologies in US EPA's Mandatory GHG Reporting Rule. No quantifiable fugitive emissions due to the Project have been identified.

The emission factors and calculated future projected actual emissions for relevant HAPs are provided in **Table 2-2**. Alabama Power estimated total HAP emissions based on a subset of HAPs listed in Section 112(b)(1) of the Clean

Air Act for inorganic compounds (including metallic compounds and acid gases) and organic compounds.[2] These estimated emissions are calculated for pollutants in which an emission factor is available from AP-42 Chapter 1.4.

The equations used to calculate the hourly emission rates and projected actual annual emissions are included in **Appendix C**.

Note that Alabama Power has conservatively excluded no increased utilization due to demand growth or other increases to emissions that are not resulting from the Project. Alabama Power reserves the right to make additional exclusions in its discretion.

[2] Emissions factors do not exist for all compounds listed in Section 112(b)(1). Alabama Power applied all available Natural Gas Combustion AP-42 Chapter 1.4 emissions factors in this analysis.

Table 2-1. Summary of Project Emission Rates and Future Projected Actual Annual Emissions

	Nominal Full-Load
Heat Input (mmBtu/hr)	7,585
Maximum Projected 12-month Heat Input (mmBtu/yr)	43,188,990[1]

Pollutant	Emission Rate (lb/hr)	Projected Actual Annual Emissions (tpy)	Emission Factor (lb/mmBtu)	Source of Emission Factor
SO_2	4.6	13.0	0.0006	40 CFR Part 75
NO_X	379.3	1,079.7	0.05	Engineering Estimate from Vendor
PM[2]	14.4	41.0	0.0019	AP-42
PM_{10}[3]	56.9	162.0	0.0075	AP-42
$PM_{2.5}$[3]	56.9	162.0	0.0075	AP-42
CO	140.3	399.5	0.0185	Engineering Estimate from Vendor
VOC	30.5	86.8	0.004	Engineering Estimate from Vendor
GHG (CO_2e)	888,183	2,528,657	117.1	GHG Reporting Rule
H_2SO_4	0.035	0.099	4.59E-06	EPRI
Lead	0.0037	0.011	4.90E-07	AP-42
Fluorides	0	0	0	n/a

1. Based on the Company's planning and transmission functions' projected needs for the Unit
2. Represents filterable PM only; AP-42 data may not include converted boilers; however, variability in data up to approximately 365% would not affect the applicability analysis.
3. Represents filterable plus condensable PM

Table 2-2. Summary of Project HAP Emission Factors and Future Projected Actual Annual Emissions

CAS ID	Pollutant	Emission Factor[1,2] (lb/mmBtu)	Projected Actual Annual Emissions (tons/yr)
7440-38-2	Arsenic	1.96E-07	4.23E-03
7440-41-7	Beryllium	1.18E-08	2.55E-04
7440-43-9	Cadmium	1.08E-06	2.33E-02
7440-47-3	Chromium, total	1.37E-06	2.96E-02
7440-48-4	Cobalt	8.24E-08	1.78E-03
7439-92-1	Lead	4.90E-07	1.06E-02
7439-96-5	Manganese	3.73E-07	8.05E-03
7439-97-6	Mercury	2.55E-07	5.51E-03
7440-02-0	Nickel	2.06E-06	4.45E-02
7782-49-2	Selenium	2.35E-08	5.07E-04
91-57-6	2-Methylnapthalene	2.35E-08	5.07E-04
56-49-5	3-Methylchloranthrene	1.76E-09	3.80E-05
	7,12-Dimethylbenz(a)anthracene	1.57E-08	3.39E-04
83-32-9	Acenaphthene	1.76E-09	3.80E-05
203-96-8	Acenaphthylene	1.76E-09	3.80E-05
120-12-7	Anthracene	2.35E-09	5.07E-05
56-55-3	Benz(a)anthracene	1.76E-09	3.80E-05
71-43-2	Benzene	2.06E-06	4.45E-02
50-32-8	Benzo(a)pyrene	1.18E-09	2.55E-05
205-99-2	Benzo(b)fluoranthene	1.76E-09	3.80E-05
191-24-2	Benzo(g,h,i)perylene	1.18E-09	2.55E-05
75343	Benzo(k)fluoranthene	1.76E-09	3.80E-05
218-01-09	Chrysene	1.76E-09	3.80E-05
53-70-3	Dibenzo(a,h)anthracene	1.18E-09	2.55E-05
25321-22-6	Dichlorobenzene	1.18E-06	2.55E-02
206-44-0	Fluoranthene	2.94E-09	6.35E-05
86-73-7	Fluorene	2.75E-09	5.94E-05
50-00-0	Formaldehyde	7.35E-05	1.59E+00
110-54-3	Hexane	1.76E-03	3.80E+01
193-39-5	Indeno(1,2,3-cd)pyrene	1.76E-09	3.80E-05
91-20-3	Naphthalene	5.98E-07	1.29E-02
85-01-8	Phenanthrene	1.67E-08	3.61E-04
129-00-0	Pyrene	4.90E-09	1.06E-04
108-88-3	Toluene	3.33E-06	7.19E-02
	Polycyclic Organic Matter (POM)[3]	8.65E-08	1.87E-03
		Total	39.98

1. Emissions Factor Sources: US EPA AP-42, Compilation of Air Pollutant Emission Factors, 5th Edition, Natural Gas Combustion, Tables 1.4-3 and 1.4-4, 2003.
2. Emissions factors not available for all Section 112(b) HAPS. Table includes all HAPs for which AP-42 emissions factors are available.
3. POM is a subset of the sum of individual organic compounds and is not included in the total HAPs emitted in TPY as it is included for the individual compounds.

3.0 New Source Review Applicability

3.1 Introduction

Plant Barry is an existing major source for the purposes of NSR. Alabama Power is applying for an Air Permit to Construct under ADEM Admin. Code r. 335-3-14. Any project that results in both a significant emissions increase and a significant net emissions increase of a regulated NSR pollutant is subject to PSD review unless otherwise exempt.

An emissions increase is considered significant if it exceeds the applicable significance thresholds established by US EPA and adopted by ADEM at ADEM Admin. Code r. 335-3-14-.04(2)(w). Plant Barry is located in an "unclassifiable/attainment or unclassifiable" area for all criteria pollutants. As such, only PSD significance thresholds potentially apply for all regulated pollutants for purposes of evaluating PSD applicability.

Determining whether a significant increase will occur following the Project is based on the applicable test identified in ADEM Admin. Code r. 335-3-14-.04(1)(f). Accordingly, the following paragraphs compare the baseline actual emissions to the future projected actual emissions of regulated NSR pollutants after the Project (ADEM Admin. Code r. 335-3-14-.04(2)(nn) and 335-3-14-.04(2)(uu)1).

3.2 Emissions Calculations

To assess PSD applicability for existing units, ADEM regulations require a comparison of baseline actual emissions to projected actual emissions after the Project. Because Plant Barry Unit 5 is an "existing electric utility steam generating unit," "Baseline actual emissions" were determined in accordance with ADEM Admin Code r. 335-3-14-.04(2)(uu)1 as "the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding" the date Alabama Power will begin actual construction (October 2026). ADEM Admin Code r. 335-3-14-.04(2)(uu) also authorizes "the use of a different time period . . . that is more representative of normal source operations," and Alabama Power reserves the right to request a different baseline period at its discretion.

A summary of the projected actual emissions is presented in Section 2 and the formulas used to calculate projected actual emissions are provided in **Appendix C**. **Table 3-1** provides the baseline actual emissions for the Project and a comparison of the baseline actual emissions to future projected actual emissions for the regulated NSR pollutants.

For the baseline actual emissions calculations, the SO_2 and NOx data are based on continuous emissions monitoring systems (CEMS), while the CO and VOC data are calculated using historical baseline emission factors and heat input totals from CEMS. Filterable and condensable PM baseline actual emission rates are calculated using PM emission stack test results and heat input totals from CEMS. PM_{10} and $PM_{2.5}$ emissions include both filterable and condensable PM. The filterable fraction of PM_{10} and $PM_{2.5}$ emissions are based upon the particle size distribution provided in AP-42 Chapter 1 External Combustion Sources controlled with an ESP and scrubber, Table 1.1-6. The baseline actual emission rate for H_2SO_4 is calculated using the methodologies outlined in the 2018 EPRI paper entitled "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants." Baseline actual emissions for lead and fluorides are based on the heat input from CEMS and the concentration of these elements in the coal for reporting years 2021-2023. The methodologies outlined in EPRI's Emission Factors Handbook entitled "Guidelines for Estimating Trace Substance Emissions from Fossil-Fuel-Fired Steam Electric Power Plants" were used to calculate lead and fluoride emissions. As mentioned in Section 2.4, the emission factors for GHGs are derived from the US EPA GHGRR and are converted to lb/mmBtu of CO_2e.

Table 3-1. Comparison of Baseline Actual Emissions to Future Projected Actual Emissions

Regulated NSR Pollutant	24-Month Baseline Period	Baseline Actual Emissions (tpy)	Projected Actual Emissions (tpy)	Difference in Emissions (tpy)	Baseline Emission Factor (lb/mmBtu)	Source of Baseline Emission Factor
SO_2	Nov 2021 - Oct 2023	420.7	13.0	-407.8	0.0273	CEMS
NO_X	Nov 2021 - Oct 2023	1,150.5	1,079.7	-70.8	0.0746	CEMS
PM	Nov 2021 - Oct 2023	131.0	41.0	-89.9	0.0085	Stack Tests
PM_{10}	Nov 2021 - Oct 2023	87.0	162.0	75.0	0.0056	Stack Tests / AP-42
$PM_{2.5}$	Nov 2021 - Oct 2023	44.1	162.0	117.9	0.0029	
CO	Nov 2021 - Oct 2023	465.23	399.5	-65.7	0.0302	AIRS
VOC	Nov 2021 - Oct 2023	54.3	86.8	32.5	0.0035	AIRS
GHG (CO_2e)	Nov 2021 - Oct 2023	3,190,182.0	2,528,657	-661,525	206.814	CEMS + GHGRR
H_2SO_4	Nov 2021 - Oct 2023	212.0	0.099	-211.9	1.37E-02	2018 EPRI Paper
Lead	Nov 2021 - Oct 2023	0.017	0.011	-0.006	1.10E-06	EPRI EF Handbook
Fluorides	Nov 2021 - Oct 2023	0.23	0.00	-0.23	1.48E-05	EPRI EF Handbook

3.3 Significant Emissions Increase and Significant Net Emissions Increase

When applying the "actual-to-projected-actual applicability test for projects that only involve existing emissions units" consistent with ADEM Admin. Code r. 335-3-14-.04(1)(f), the Project only results in a significant emissions increase for PM_{10} and $PM_{2.5}$. Therefore, a PSD review is required for the Project for PM_{10} and $PM_{2.5}$. A summary of the significant emissions increase analysis is provided in **Table 3-2**.

For the remaining regulated NSR pollutants, the emission analysis demonstrates that the emissions from this Project are either negative or below the PSD thresholds and satisfy the "source obligation" requirements of ADEM Admin. Code r. 335-3-14-.04(17)(d). [3]

Table 3-2. Significant Emissions Increase Analysis

Regulated NSR Pollutant	PSD Significant Emission Rate (tpy)	Project Change in Emissions (tpy)	Significant Emissions Increase
SO_2	40	-407.8	No
NO_X	40	-70.8	No
PM	25	-89.9	No
PM_{10}	15	75.0	Yes
$PM_{2.5}$	10	117.9	Yes
CO	100	-65.7	No
VOC	40	32.5	No
GHG (CO_2e)	75000	-661,525	No
H_2SO_4	7	-211.9	No
Lead	0.6	-0.006	No
Fluorides	3	-0.23	No

[3] Non-applicability of ADEM Admin. Code r. 335-3-14-.04(17)(e) to be confirmed following completion of initial emissions testing.

4.0 Requirements and Standards

This section identifies the federal and state air quality regulations that will govern construction and operation of the proposed Project. Specifically, the following regulations and standards were reviewed for applicability to the proposed Project:

- National Ambient Air Quality Standards (NAAQS);
- Prevention of Significant Deterioration (PSD) Regulation;
- Good Engineering Practice (GEP) Stack Height Regulations;
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Compliance Assurance Monitoring (CAM);
- Acid Rain Program Regulations (ARP);
- Risk Management Program (RMP);
- Cross-State Air Pollution Rule (CSAPR);
- Greenhouse Gas Reporting Rule (GHGRR);
- Alabama Department of Environmental Management (ADEM), Air Division – Air Pollution Control Program; and
- Alabama State Implementation Plan (SIP)

The Federal regulatory programs, as administered and delegated by the US EPA, have been developed under the authority of the Clean Air Act (CAA or Act) and its amendments. These regulatory programs have been adopted by ADEM and are included in ADEM Admin. Code r. 335-3. The following subsections review the key elements of the regulatory programs and the impact they have on the permitting and operation of the proposed Project. Discussion of other applicable Alabama regulatory requirements is also included in this section.

4.1 Ambient Air Quality Classification

The 1970 CAA provides US EPA with specific authority to establish National Ambient Air Quality Standards (NAAQS) for six common air pollutants to protect public health (primary standards) and welfare (secondary standards). The federally promulgated standards that are applicable to this Project, and which have been adopted by ADEM, are presented in **Table 4-1**.

Table 4-1. Applicable National Ambient Air Quality Standards

Pollutant	Averaging Period	Primary Standard ($\mu g/m^3$)	Secondary Standard ($\mu g/m^3$)
PM_{10}	24-hour(1)	150	150
$PM_{2.5}$	24-hour(2)	35	35
	Annual(3)	9	15

1. Not to be exceeded more than an average of one day per year over three years.
2. Compliance with the 24-hour standard is demonstrated when the 3-year average (5-year average in a modeling demonstration) of the 98th-percentile (8th High) 24-hour concentration is below the standard.
3. Not to be exceeded by the arithmetic average of the annual arithmetic averages from 3 successive years.

Source: EPA 40 CFR 50

The 1990 CAA Amendments call for a review of the ambient air quality of all regions of the United States. By March 15, 1991, states were required to file with US EPA designations of all areas as either attainment, nonattainment, or unclassifiable. Areas of the country that had monitored air quality levels equal to or better than these standards (i.e., ambient concentrations less than a standard) as of March 15, 1991, became designated as "attainment areas," while those areas where monitoring data indicated air quality concentrations greater than the standards became classified as "nonattainment areas."

The designation of "unclassifiable" indicates that there is insufficient monitoring data to demonstrate that the area has attained the federal standards; however, the limited data available indicates that the standard has been achieved. Areas with this classification are treated by the US EPA as attainment areas for permitting purposes.

The Project will be located at Alabama Power's Plant Barry, which is situated in Bucks, Mobile County, Alabama. Mobile County is currently classified as unclassifiable/attainment or unclassifiable for all pollutants.

4.2 Prevention of Significant Deterioration (PSD) Program

4.2.1 PSD Applicability

For PSD applicability, the Project's emissions were reviewed to determine whether it constitutes a major stationary source or a major modification. Plant Barry is defined as a major stationary source because it is one of the 28 major source types listed in ADEM Admin. Code r. 335-3-14-.04(2)(a)(1), and it has the potential to emit more than 100 tons per year of at least one NSR regulated pollutant. A major modification is defined as a physical or operational change at a major stationary source that results in a net emissions increase[4] above the PSD significant emission rates, as identified in **Table 4-2**.

Table 4-2. PSD Significant Emission Rates

Pollutant	Significant Emission Rate[1] (tpy)
CO	100
NO_X	40
SO_2	40
PM	25
PM_{10}	15
$PM_{2.5}$	10
Ozone (O_3)	40 of VOC or NO_X
Lead (Pb)	0.6
Fluorides (excluding HF)	3
Sulfuric Acid Mist (H_2SO_4)	7
Total Reduced Sulfur (including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10
Greenhouse Gases (as CO_2e)	75,000

1. Source: ADEM Admin. Code r. 335-3-14-.04(2)(w)

The Project will have emission increases above the PSD significance levels for PM_{10} and $PM_{2.5}$, as previously shown in **Table 3-2**. Therefore, PSD review is required only for these pollutants.

[4] Alabama Power did not rely on any source-wide netting to calculate net emissions. Accordingly, for this Project no contemporaneous emissions changes are identified, and only changes in Project emissions are determined pursuant to ADEM Admin. Code r. 335-3-14.04(1)(e).

4.2.2 PSD Program Requirements

The following sections provide a summary of the application requirements for projects subject to permitting under PSD.

Best Available Control Technology

The requirements for Best Available Control Technology (BACT) were promulgated within the framework of the PSD regulations in the 1977 CAA Amendments. Guidelines for the evaluation of BACT can be found in US EPA's Air Pollution Control Cost Manual (US EPA 2018) and in the Draft New Source Review Workshop Manual (US EPA 1990). These guidelines were drafted by US EPA as a framework or tool for the BACT process. US EPA has also published guidance on BACT for greenhouse gas emissions (http://www.epa.gov/nsr/ghgpermitting.html). ADEM has developed its own PSD regulations that have been approved by the US EPA and incorporated into the Alabama SIP under ADEM Admin. Code r. 335-3-14-.04. The BACT analysis for the Project is presented in Section 5.

Air Quality Monitoring Requirements

In accordance with the requirements of ADEM Admin. Code r. 335-3-14-.04, a PSD permit application must contain an analysis of existing ambient air quality data in the affected area for all regulated pollutants for which the Project is subject to PSD review. The analysis of existing air quality can be air monitoring data from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source. The Project will use ambient monitoring data from ADEM's existing ambient monitoring network to satisfy the requirements for pre-construction monitoring (see Appendix H).

Source Impact Analysis

A source impact analysis must be performed for a proposed project for each pollutant that triggers PSD review to demonstrate that the Project will not cause or contribute to a violation of any NAAQS or any applicable maximum allowable increase over the baseline concentration in any area. PSD regulations specify that new major sources or modifications to existing major sources may change baseline air quality only by a defined amount. This limited incremental degradation is known as a PSD increment. PSD increments have been established for Class I and Class II areas for PM_{10} and $PM_{2.5}$ (see **Table 4-3**). The allowable change, or increment, is dependent on the classification of the area in which the action is to take place. When PSD regulations were first promulgated, three area classifications were proposed based on criteria set in the 1977 CAA.

Class I areas are federally protected areas and include specifically defined national parks, national forests, and wilderness areas. Class III increments are the least restrictive of the three PSD Classes, but to date, no Class III areas have been officially designated. The remainder (and vast majority) of the country (including Mobile County) is designated as a Class II area.

The PSD regulations specifically provide for the use of atmospheric dispersion modeling in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with NAAQS and allowable PSD increments. Designated US EPA models, identified in 40 CFR Part 51, Appendix W, are normally used in performing air quality analyses. Guidance for the use and application of dispersion models is presented in the US EPA publication Guideline on Air Quality Models (GAQM, 40 CFR Part 51, Appendix W). The source impact analysis for criteria pollutants may be limited to only the new or modified sources if a net increase in impact due to the new or modified source is below the significant impact levels (SILs) presented in **Table 4-3**.

Various periods of meteorological data can be utilized for an impact analysis. A minimum 1-year period of onsite data, or a 5-year period of representative meteorological data is normally required.

Table 4-3. Allowable PSD Increments and Significant Impact Levels for applicable pollutants (µg/m^3)

Pollutant	Averaging Period	PSD Increments (µg/m^3)		Significant Impact Levels (µg/m^3)	
		Class I	Class II	Class I	Class II
PM_{10}	24-hour(1)	8	30	0.3	5
	Annual(2)	4	17	0.2	1
$PM_{2.5}$	24-hour(1)	2	9	0.27	1.2
	Annual(2)	1	4	0.03	0.13

1. Not to be exceeded more than once per year (PSD Increment).
2. Not to be exceeded (PSD Increment).

Source: US EPA 40 CFR 50 and ADEM Modeling Guidance (https://adem.alabama.gov/sites/default/files/2025-06/AeromodModelingGuidelines.pdf)

In addition to the standard air quality analyses, federal regulations require that applicants of PSD projects conduct an analysis of the impairment to visibility and the effects on soils and vegetation that would occur as a result of project construction and operation. Impacts due to commercial, residential, industrial, and other growth in the vicinity of the Project also must be addressed to the extent they are a result of the proposed action. These additional requirements are addressed in Section 8 of this application.

4.3 Good Engineering Practice (GEP) Stack Height Analysis

The 1977 CAA requires that the degree of emission limitation required for control of any pollutant not be affected by a stack which exceeds the GEP height (US EPA 1985). These requirements are described in more detail in Section 6.6.

4.4 Applicability of New Source Performance Standards (NSPS)

The NSPS subparts potentially applicable to this Project include:

- Subpart A – General Provisions;
- Subpart Da – Standards of Performance for Electric Utility Steam Generating Units;
- Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units;
- Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units; and
- Subpart UUUUb - Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

4.4.1 Subpart A – General Provisions

All affected sources which are subject to a NSPS under 40 CFR Part 60 are subject to the general provisions of 40 CFR Part 60 Subpart A, unless specifically excluded by the source-specific NSPS. Since the emissions unit will not be subject to any NSPS standards, it will not be subject to Subpart A.

4.4.2 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units

40 CFR Part 60, Subpart Da applies to electric utility steam generating units which commence construction, modification, or reconstruction after September 18, 1978 and that have a maximum design heat input capacity greater than 250 MMBtu/hr. Barry Unit 5 is a steam electric generating unit constructed prior to September 18, 1978, and therefore is not currently subject to Subpart Da. Subpart Da becomes applicable if either:

1. the Project qualifies as a reconstruction; or
2. the Project causes an increase in the maximum hourly emission rate of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

40 CFR Part 60.42Da (f)(1) states that any owner or operator of an affected facility that combusts only gaseous or liquid fuels with potential SO_2 emissions rates of 0.060 lb/mmBtu or less, and that does not use a post-combustion technology to reduce emissions of SO_2 or PM, is exempt from the PM emissions limits in this subpart. Thus, for a natural gas fired unit, the relevant pollutants regulated under Subpart Da are SO_2 and NOx only. For Barry Unit 5, the maximum achievable hourly emissions rate is not anticipated to increase for either SO2 or NOx, and therefore the Project does not constitute a modification under this subpart. Per 40 CFR §60.15(b)(1)-(2), “reconstruction” occurs when (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible for the facility to meet the applicable standards. The fixed capital cost for the Unit 5 conversion is expected to be well below the

50 percent threshold, and therefore the Project does not constitute a reconstruction under the definition provided in §60.15(b). Accordingly, Subpart Da will not apply.

4.4.3 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

40 CFR Part 60, Subpart TTTT was promulgated on October 23, 2015. It is applicable to each electric utility steam generating unit that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014 and before May 23, 2023. The Barry Unit 5 natural gas conversion will occur after the applicability date and thus Subpart TTTT does not apply. However, EPA has proposed regulatory changes that could affect these applicability dates. Consequently, Alabama Power reviewed the substantive applicability criteria of Subpart TTTT. Pursuant to those criteria in Subpart TTTT (40 CFR 60.5509(b)(7)), an otherwise modified EGU is not subject to the requirements of Subpart TTTT unless that modification results in an hourly increase of CO_2 emissions (mass per hour) of more than 10 percent. The Barry Unit 5 natural gas conversion project satisfies this non-applicability criteria (see **Table 2-1** and **Table 3-1**). Thus, even if the applicability dates are amended to include any units that commenced modification after May 23, 2023, Barry Unit 5 would still not be an affected unit under this subpart.

4.4.4 Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

40 CFR Part 60, Subpart TTTTa was promulgated on May 9, 2024. It is applicable to each coal-fired electric generating unit with a heat input greater than 250 MMBtu/hr that serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system, and that commences modification on or after May 23, 2023. The Project will convert Unit 5 to natural gas-firing and will no longer be coal-fired. Therefore, Unit 5 will not be subject to Subpart TTTTa.

4.4.5 Subpart UUUUb- Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

Subpart UUUUb establishes emission guidelines and approval criteria for States to adopt plans that establish standards of performance for GHG emissions from EGUs that are not subject to either Subparts TTTT or TTTTa. Subpart UUUUb does not directly regulate EGUs. Accordingly, Unit 5 is not subject to Subpart UUUUb. Alabama has not at this time adopted a state plan; however, any obligation imposed through an approved state plan will be addressed when that plan becomes effective.

4.4.6 Non-Applicability of All Other NSPS

NSPSs are developed for particular industrial source categories. The applicability of a particular NSPS to the proposed project can be readily ascertained based on the industrial source category covered. All other NSPSs are not applicable to the proposed project.

4.5 40 CFR Part 61 National Emission Standards Hazardous Air Pollutants (NESHAPs)

The proposed Project is not subject to any of the 40 CFR Part 61 NESHAPs.

4.6 40 CFR Part 63 NESHAPs

A major source of hazardous air pollutants (HAPs) is any stationary source that has the potential to emit 10 tpy or more of a single HAP or 25 tpy of combined HAPs. 40 CFR Part 63 Maximum Achievable Control Technology

(MACT) standards have been promulgated for major sources and, in a few cases, for area sources. Plant Barry is an existing major source of HAPs. ADEM has incorporated by reference these rules under ADEM Admin. Code r. 335-3-11.

4.6.1 Subpart A – General Provisions

40 CFR Part 63, Subpart A contains national emissions standards for HAPs defined in Section 112(b) of the Clean Air Act. All affected sources which are subject to a MACT standard under 40 CFR Part 63 are subject to the general provisions of NESHAP Subpart A, unless specifically excluded by the source-specific NESHAP.

4.6.2 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

The Major Source Industrial Boiler MACT standard (40 CFR Part 63, Subpart DDDDD), finalized on January 31, 2013, applies to certain boilers and process heaters located at a major source of HAPs. As outlined in 40 CFR 63.7491 (a), electric utility steam generating units covered by 40 CFR Part 63 Subpart UUUUU or natural gas-fired EGUs firing at least 85% natural gas on an annual heat input basis, are not subject to this subpart. A *natural gas-fired electric utility steam generating unit* is defined at 40 CFR §63.10042 as:

> *"…an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections."*

Because Unit 5 will be a solely natural gas-fired unit and therefore meets this definition, it is not subject to Subpart DDDDD.

4.6.3 Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

The Area Source Industrial Boiler MACT standard (40 CFR Part 63, Subpart JJJJJJ) does not apply to facilities at major sources of HAPs and thus Barry Unit 5 will not be subject to these requirements.

4.6.4 Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

EPA finalized the Mercury and Air Toxics Standards (MATS) rule, 40 CFR Part 63 Subpart UUUUU, on February 16, 2012. Plant Barry Unit 5 is currently subject to the MATS rule as a coal-fired electric generating unit. After the unit is converted to a natural gas-fired unit, the unit will no longer be subject to this rule as outlined in 40 CFR 63.9983(b) as it will meet the definition of a natural gas-fired electric utility steam generating unit. As noted above, *Natural gas-fired electric utility steam generating unit* is defined at 40 CFR §63.10042 as:

> *"…an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections."*

Because Unit 5 will be a solely natural gas-fired unit and therefore meets this definition, it will not be subject to Subpart UUUUU.

4.7 Acid Rain Program

Plant Barry Unit 5 is subject to the Acid Rain rules contained in 40 CFR Parts 72, 73, 75, and 76 which are incorporated by reference at ADEM Admin. Code r. 335-3-18. The applicable Acid Rain permit is contained in the Plant Barry Title V Major Source Operating Permit.

4.8 Compliance Assurance Monitoring

Compliance Assurance Monitoring (CAM) regulations are codified in 40 CFR Part 64. CAM is applicable to sources on a per-pollutant basis only if all of the following criteria are met:

1) The source must be subject to an emission limit or standard, other than an emission limitation or standard that is exempt as outlined below:
    a. established after November 15, 1990 pursuant to section 111 or 112 of the Act;
    b. establishing Stratospheric ozone protection requirements under title VI of the Act;
    c. establishing Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act;
    d. that applies solely under an emissions trading program approved by the Administrator under the Act;
    e. that imposes an emissions cap that meets the requirements specified in 70.4(b)(12) or 71.6(a)(13)(iii); and
    f. for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in 64.1.
2) The source must use a control device to achieve compliance with that emission limit or standard, and
3) The source must have potential pre-control device emissions in the amount required to classify the unit as a major source under Part 70 of the Clean Air Act (CAA) (i.e., 100 tons/year).

Unit 5 will not utilize a control device to meet the State PM limit of 0.12 lb/mmBtu; therefore, CAM is not applicable.

4.9 Risk Management Program (RMP), Section 112(r)

Title III of the 1990 CAA Amendments contains requirements for subject facilities that store and/or process certain hazardous substances for ensuring their safe use. Under these requirements, facilities must identify and assess their hazards and carry out certain activities designed to reduce the likelihood and severity of accidental chemical releases. Section 112(r) of the CAA, codified in 40 CFR Part 68, mandates the US EPA to publish rules to develop and implement a program for sources with more than the threshold quantity of a listed regulated substance to identify, prevent, and minimize the consequences of accidental releases. The three elements that should be incorporated into an RMP include:

- Hazard Assessment;
- Prevention Program; and
- Emergency Response Program.

The existing Plant Barry facility currently stores anhydrous ammonia above the threshold quantity for use in the SCR and has a Risk Management Program in place.

4.10 Cross-State Air Pollution Rule

On July 6, 2011, the US EPA promulgated the Cross-State Air Pollution Rule (CSAPR). CSAPR applicability and requirements are codified at 40 CFR 97, ADEM Admin. Code r. 335-3-5.06 through 335-3-5-.36, and ADEM Admin. Code r. 335-3-8-.07 through .70. CSAPR requires states to address interstate transport of SO_2 and NO_x emissions that affect downwind states' ability to attain and maintain ozone and $PM_{2.5}$ NAAQS.

Plant Barry Unit 5 is currently subject to the requirements of CSAPR. Alabama Power will continue to hold enough allowances to cover Unit 5's emissions and comply with the permitting, monitoring, recordkeeping and reporting requirements set forth by CSAPR.

4.11 Greenhouse Gas Reporting Rule

The Greenhouse Gas Reporting Rule (GHGRR), codified in 40 CFR Part 98, requires facilities belonging to certain source categories to report their annual GHG emissions to US EPA. Included on US EPA's list of affected source categories are electric generating units that report CO_2 mass emissions year-round through 40 CFR Part 75. Such affected facilities must report their annual GHG emissions from not only the electric generating unit, but from all stationary fuel combustion sources (excluding emergency equipment) located at the facility. Alabama Power will continue to report GHG emissions from Unit 5 as applicable.

4.12 Other Applicable Alabama Rules and Regulations

As previously mentioned, ADEM has adopted or incorporated by reference many of the federal regulations into the State Implementation Plan (SIP), that has been approved by US EPA, under ADEM Admin. Code r. 335-3. Plant Barry Unit 5 will also comply with the appropriate paragraphs of the following existing Alabama SIP requirements, unless otherwise exempt.

ADEM Admin Code r. 335-3-1-.04	Monitoring, Records, and Reporting
ADEM Admin Code r. 335-3-1-.05	Sampling and Testing Methods
ADEM Admin Code r. 335-3-1-.08	Prohibition of Air Pollution
ADEM Admin Code r. 335-3-1-.15	Emissions Inventory Reporting
ADEM Admin Code r. 335-3-4-.01	Visible Emissions
ADEM Admin Code r. 335-3-4-.02	Fugitive Dust and Fugitive Emissions
ADEM Admin Code r. 335-3-4-.03	Fuel Burning Equipment
ADEM Admin Code r. 335-3-4-.04	Process Industries - General
ADEM Admin Code r. 335-3-5-.01	Fuel Combustion
ADEM Admin Code r. 335-3-14	Air Permits
ADEM Admin Code r. 335-3-16	Major Source Operating Permits

335-3-1-.04 Monitoring, Records, and Reporting

ADEM Admin. Code r. 335-3-1-.04 specifies requirements for frequency and format of various reports, emissions testing and monitoring. Upon completion of the Project, Alabama Power will comply with provisions in this regulation as applicable.

335-3-1-.05 Sampling and Testing Methods

ADEM Admin. Code r. 335-3-1-.05 specifies that any required sampling and testing be conducted under ADEM approved procedures and methods. Upon completion of the Project, Alabama Power will comply with any applicable sampling and testing required by ADEM.

335-3-1-.08 Prohibition of Air Pollution

ADEM Admin. Code r. 335-3-1-.08 prohibits air pollution as defined in 335-3-1-.02(1)(e) by the discharge of air contaminants for which no ambient standard has been established. Upon completion of the Project, Alabama Power will continue to comply with this regulation as specified in the General Permit Provisos of the Plant Barry Title V Major Source Operating Permit.

335-3-1-.15 Emissions Inventory Reporting

ADEM Admin. Code r. 335-3-1-.15 specifies requirements for reporting of emissions as it pertains to 40 CFR Part 51, Appendix A. Upon completion of the Project, Alabama Power will continue to comply with the provisions in this regulation as applicable.

335-3-4-.01 Visible Emissions

ADEM Admin. Code r. 335-3-4-.01 regulates visible emissions from stationary sources. Barry Unit 5 will meet the definition of a natural gas-fired unit. Also, operation of the electrostatic precipitator will no longer be necessary. Alabama Power will comply with the applicable provisions of ADEM Admin. Code r. 335-3-4-.01, and propose compliance with the opacity standards as applicable, and upon ADEM's request, be determined by EPA Reference Method 9 in Appendix A of 40 CFR Part 60.

335-3-4-.02 Fugitive Dust and Emissions

This regulation applies to sources which have the potential to cause fugitive dust to become airborne. Plant Barry will continue to comply with ADEM's fugitive dust requirements as specified in the General Permit Provisos of its Title V Major Source Operating Permit.

335-3-4-.03 Fuel Burning Equipment

ADEM. Admin. Code r. 335-3-4-.03 prohibits the emission of particulate matter from fuel burning equipment in excess of rates provided in Table 4-1 of the referenced administrative code. Mobile County is a Class I County. Alabama Power will comply with Alabama's fuel-burning equipment regulations as applicable and conduct any particulate matter emissions testing required by ADEM.

335-3-4-.04 Process Industries General

This requirement limits emissions of PM from general manufacturing processes and other operations at industrial facilities. The modified Unit 5 will not be subject to this regulation.

335-3-5-.01 Fuel Combustion

This regulation limits SO_2 emissions from fuel combustion units in Category I and Category II counties. Mobile County (the location of Plant Barry) is a Category I county and therefore, emissions of sulfur oxides (as SO_2) from the fuel combustion units are required to be limited to 1.8 lb/MMBtu. The modified unit will burn natural gas and is therefore anticipated to have relatively low emissions of SO_2. The existing SO_2 and flow monitors will no longer be utilized, and a fuel flowmeter will be installed in accordance with 40 CFR Part 75, Appendix D.

335-3-14 Air Permits

Alabama Power evaluated the Project's PSD applicability and determined that PSD review is triggered for PM_{10} and $PM_{2.5}$. ADEM Admin. Code r. 335-3-14-.04 (PSD Permitting) applies to the Project and requires that a PSD permit be obtained prior to commencing construction of the Project. This document serves as the application for issuance of a PSD permit for the Project.

335-3-16 Major Source Operating Permits

Plant Barry currently operates under a Title V Major Source Operating Permit (MSOP) (Facility Number 503-1001) and will remain a Title V major source post-Project. Alabama Power will be required to submit an application to incorporate the PSD construction permit into its current MSOP within 12 months of commencing operation.

5.0 Control Technology Review

5.1 Technical Approach

ADEM's PSD regulations (ADEM Admin Code r. 335-3-14-.04 (9)(c)) require a Best Available Control Technology (BACT) analysis for each new major source or major modification at an existing major source that will result in a significant net emissions increase of an NSR regulated pollutant. As described in Section 3 of this application, the emissions increases associated with the Barry Unit 5 natural gas conversion are sufficient to trigger PSD review for particulate matter less than 10 micrometers in diameter (PM_{10}) and particulate matter less than 2.5 micrometers in diameter ($PM_{2.5}$). Because the control options are undifferentiated, for the purposes of this BACT review, these individual pollutants are being treated together as particulate matter (PM).

BACT is defined in ADEM Admin Code r. 335-3-14-.04 (2)(l) as:

> *…an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Director, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR 60 and 61. If the Director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

Guidelines for the evaluation of BACT can be found in EPA's Guidance for Determining BACT Under PSD[5] and in the New Source Review Workshop Manual. These guidelines provide recommendations for a consistent approach to BACT and ensure that the impacts of alternative emission control systems are measured by the same set of parameters. Unlike many of the Clean Air Act programs, the PSD program's BACT evaluation is determined on a case-by-case basis. To assist applicants and regulators with the case-by-case process, in 1987 U.S. EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans.[6] Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option is not achievable in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.[7]

> BACT is to be set at the lowest value that is achievable. However, there is an important distinction between emission rates achieved at a specific time, under specific conditions, on a specific unit, and an emission limitation that a unit will be able to meet continuously over its operating life. As discussed by the DC Circuit

[5] Memo from David G. Hawkins, EPA Headquarters, on Guidance for Determining BACT under PSD to EPA Reg'l Adm'rs (Jan. 4, 1979) (on file with the U.S. EPA).
[6] Memo from J. Craig Potter, EPA Headquarters, on Improving New Source Review Implementation to EPA Reg'l Adm'rs (Dec. 1, 1987) (on file with the U.S. EPA).
[7]Applicants and ADEM are not obligated to apply the top-down method and to the extent any particular BACT analysis deviates from EPA's guidance, that is permissible provided the regulatory criteria for BACT are satisfied. See PLUMB. AND ST'MFITTERS v. ADEM, 647 So.2d 793 (App. Ala. 1994).

> Court of Appeals “where a statute requires that a standard be “achievable,” it must be achievable “under most adverse circumstances which can reasonably be expected to recur.”[8]

U.S EPA has reached similar conclusions in prior determinations for PSD permits.

> *“Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured ‘emissions rates,’ which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the ‘emissions limitation’ determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility’s life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the “emissions limitation” that is “achievable” for that pollution control method over the life of the facility. Accordingly, because the “emissions limitation” is applicable for the facility’s life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.”*[9]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. Accordingly, while viewing individual unit performance or permitted emission limits can be instructive in evaluating what BACT might be, these data must be viewed carefully, as rarely will the data be adequate because BACT must be set at a level that a unit can achieve with the identified technology during its entire operating life.

Accordingly, when evaluating BACT, published emission limits for similar source types must be used with care in assessing what is “achievable.” Limits established for facilities that were never built are inherently unreliable indicators, as they have never been demonstrated, and the permittee never assumed a significant liability in having to meet such limits.[10] For similar reasons, permitted units that have not yet commenced construction must also be viewed with care.

5.1.1 BACT Assessment Methodology

The following sections describe the five steps of the top-down approach and provide detail on the BACT assessment methodology utilized in preparing the BACT analysis for the Barry Unit 5 natural gas conversion.

Step 1

The first step is to define the spectrum of processes and/or add-on control options potentially applicable to the emissions unit and pollutant under review. There is no specific methodology that is required to be used to identify all available control options for a given source or pollutant. The most comprehensive source of this information, however, is US EPA’s RACT/BACT/LAER Clearinghouse (RBLC). This searchable database of emission control technology determinations is maintained by US EPA, and as such, is generally the starting point for developing a list of potentially available emission control technologies or options.

Step 2

The second step is to evaluate the technical feasibility of the control options identified in the first step and to reject those that can be demonstrated as technically infeasible based on an engineering evaluation or on chemical or physical principles. In accordance with US EPA’s 1990 Workshop Manual, two key concepts are evaluated to determine whether an undemonstrated control option is technically feasible: "availability" and "applicability." A control option is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available control option is "applicable" if it can reasonably be installed and operated on the source type under consideration. A control option that is available and applicable is technically feasible. The following criteria are considered in determining technical feasibility: previous commercial-scale demonstrations, precedent based on issued PSD permits, state requirements for similar sources, technology transfer, and engineering evaluations for the control options or work practice standards considered.

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[8] *Sierra Club v. E.P.A.*, 167 F.3d 658, 665 (D.C. Cir. 1999).

[9] *In re Newmont Nevada Energy Inv., LLC, TS Power Plant*, 2005 WL 4905114, at *13 (Dec. 21, 2005).

[10] See *Port Arthur Cmty. Action Network v. Texas Comm'n on Env't Quality*, 147 F.4th 560, 564 (5th Cir. 2025) (rejecting emission limits from a permitted but never constructed facility in a BACT analysis on the basis that there is “no ‘operational data’ show[ing] that those limits are actually achievable.”)

Step 3

The third step involves ranking each technically feasible control option in decreasing order of overall emissions control effectiveness considering specific operating constraints of the emission unit in question. After determining what control efficiency is achievable with each technically feasible control option, the alternatives are ranked into a hierarchy from most to least effective. Typically, the Step 3 ranking presents an array of control options, along with information such as control efficiencies (% pollutant removed or controlled), expected emission rate (tons/year, pounds/hour), expected emission reduction (tons/year), economic impacts (cost effectiveness), and adverse environmental and energy impacts. However, an applicant proposing the top control option as BACT need not provide cost and other detailed information regarding other control options.

Step 4

The fourth step consists of an objective evaluation of the energy, environmental, and economic impacts to arrive at a control technology or level of control that is representative of BACT. The economic evaluation is carried out using procedures outlined in the US EPA's Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual[11]. The economic evaluation considers the annualized control cost (in dollars per ton of emissions removed) for the proposed source for each control option evaluated. This evaluation is a site-specific evaluation and the fact that a particular technology or level of emissions control has been concluded to be representative of BACT at another facility does not mean that the same technology or level constitutes BACT for the Barry Unit 5 natural gas conversion.

If the top control option is determined to be cost ineffective or to cause adverse energy or environmental impacts, that control option is rejected and the analysis is performed on the next most stringent control option until the technology or emissions level under consideration cannot be eliminated based on source-specific environmental, energy, or economic impacts.

Step 5

The final step is to summarize the selection of BACT and emission limitations or work practices to be incorporated into the permit along with recommended monitoring and compliance demonstration requirements, including averaging times.

5.2 BACT Review for Particulate Matter (PM)

5.2.1 Formation

Although inherently low-emitting due to the use of gaseous fuels, flue gases from natural gas fired boilers can include a combination of filterable and condensable particles. Filterable PM (FPM) emissions entrained in the flue gas can be attributable to impurities contained in the fuel, to incomplete combustion products, and to airborne dust or particles suspended in the combustion air intake. Condensable PM (CPM) is attributable primarily to sulfate aerosols and high molecular weight volatile organic compounds (unburned hydrocarbons). In addition, boilers equipped with selective catalytic reduction (SCR) to control NOx emissions can emit ammonium salts (ammonium sulfate and/or ammonium bisulfate) as a consequence of the reaction between residual amounts of ammonia used as the NOx reducing agent (i.e., ammonia slip) and sulfur compounds naturally present in the fuel. Ammonium salt emissions can either be in the form of particles (i.e., FPM) or aerosols (CPM). The presence of sulfur compounds in the fuel (which consist primarily of sulfides) thus contributes to the formation of both sulfate aerosols and ammonium salts. In this respect, the sulfide content of the natural gas fuel directly impacts a unit's PM emission rate.

The sulfide concentration in pipeline natural gas is low, but the precise concentration can fluctuate depending on the origin of the gas and the gas processing conditions. In addition, temperature and pressure changes within the pipeline can affect the solubility and phase equilibrium of the various sulfur compounds present in the gas. Such fluctuations will cause variations in the amount of CPM emitted when the gas is combusted. These fluctuations are independent of the efficiency of the combustion and instead are due solely to the content of the fuel.

In addition to fluctuations in fuel content, converted boilers, such as Barry Unit 5, have physical or design features and existing conditions that also affect the variability of a unit's FPM and CPM emission rates. For example, a boiler's combustion zone geometry and combustion air flow system capacity affects its combustion efficiency and,

[11] EPA, *EPA Air Pollution Control Cost Manual*, at Sec. 1, Ch. 2 (7th ed. 2018).

as a result, unburned hydrocarbons which can be in the form of CPM emissions. Also, converted boiler units typically exhibit increased levels of air infiltration into the combustion or boiler sections. Higher air infiltration can cause higher measured FPM emission levels due to the presence of dust particles entrained in the infiltrated air. Other aspects of a converted unit, including the presence of residual dust associated with coal operations within the interior of the boiler, may also impact a unit's measured FPM emissions rate. Notably, these contributions to FPM are unrelated to gas burner operations.

5.2.2 Step 1 – Identify PM Control Options

To identify alternative controls for particulate matter (PM) emissions at Barry Unit 5 when firing natural gas Alabama Power searched the RBLC listings, following EPA guidance. Although the RBLC categorizes boiler listings by fuel type (gas-fired vs. solid fuel-fired) and boiler type (utility, industrial, commercial) it does not have a specific category for utility boilers that have been converted from solid fuel-fired to natural gas-fired. Regardless, Alabama Power's RBLC search encompassed all large, gas-fired steam boilers in the RBLC. In addition, air permits were reviewed for utility units converted from coal firing to natural gas firing that are not listed in the RBLC, and relevant existing and proposed federal and state emissions standards were considered.

Based on the review of available literature, emission standards, air quality permits, and the RBLC, the following control strategies or technologies have been identified that could potentially be employed to reduce PM emissions from Barry Unit 5:

1. Fabric Filter (Baghouse)
2. Electrostatic Precipitator
3. Use of Gaseous Fuel
4. Good Combustion Practices

Fabric Filter (Baghouse)

A fabric filter, also referred to as a baghouse, is an air pollution control device designed to capture FPM from a flue gas stream through physical filtration. The system consists of a series of long, tubular fabric bags, which are typically constructed of woven or felted materials, housed within a steel enclosure. The flue gas stream passes through the fabric media, where the particles are trapped on the surface of the bags while the cleaned gas exits through the outlet plenum to the stack. The accumulated particles are periodically removed and collected for disposal via mechanical shaking or a high-pressure, short-duration pulse of compressed air. Because fabric filter collectors rely principally on particles either directly impacting or indirectly being intercepted by the filter bags or the accumulated dust cake, these devices are much more effective at controlling FPM emissions than CPM emissions.

Electrostatic Precipitator (ESP)

An ESP is a control device typically used in large solid fuel- or oil-fired utility boilers to remove PM from the flue gas before it is released into the atmosphere. An ESP operates by passing the particulate-laden gas stream between high-voltage discharge electrodes and grounded collection plates. The discharge electrodes apply a negative charge to the PM particles, and the electrostatic field between the electrodes and collection plates moves the charged particles toward the collection plates, where they adhere. Periodically, a rapping system mechanically strikes the plates to dislodge the accumulated dust cake, allowing the ash to fall into collection hoppers for disposal. While generally more effective at collecting FPM, certain specialized ESP designs are utilized to collect CPM (for example, wet ESP are used to control acid mist aerosols from sulfuric acid plants).

Use of Gaseous Fuel

Natural gas, which consists primarily of methane and other low molecular weight hydrocarbons, contains virtually no mineral matter or non-combustible ash. Gaseous fuels such as natural gas are easily and completely mixed with air, thus ensuring that a highly efficient combustion process will occur, characterized by low levels of residual unburned carbon (i.e., soot). Natural gas also contains very low concentrations of the elements that make up non-carbon particulate matter. When combusted, natural gas produces very low levels of FPM. As explained above, sulfate aerosols are the principal constituent of CPM from fossil fuel-fired sources. Because natural gas has a relatively low sulfur content when compared to oil and coal, combustion of natural gas also produces low levels of CPM.

Good Combustion Practices

Good combustion practices control PM emissions by providing conditions that ensure that the fuel is burned as completely and efficiently as possible. Such practices focus on ensuring that the three principal elements of the fuel combustion process (time, temperature, and adequate mixing) are maximized. Good combustion practices also include providing the physical and operational mechanisms that promote complete combustion and minimal PM formation.

Good combustion practices aim to convert all of the fuel's carbon into carbon dioxide (CO_2) rather than unburned carbon particles (soot). Maintaining a high, uniform temperature within the combustion zone of a boiler provides the thermal energy needed to sustain the hydrocarbon oxidation reactions needed for complete combustion. Providing sufficient residence time within this high temperature zone is also a necessary criterion to ensure complete combustion. Finally, providing adequate fuel-air mixing ensures that fuel constituents are intimately mixed with the oxygen needed to sustain combustion.

Controlling the air-to-fuel ratio is one of the key operational aspects of good combustion practices needed for complete combustion. Good air-fuel ratio control involves providing for the optimal amount of excess air beyond the stoichiometric requirement needed for complete combustion and minimum soot formation. Burners designed to promote rapid, thorough fuel-air mixing and to maintain a uniform temperature profile throughout a boiler's combustion zone represent important physical aspects to good combustion practices.

No additional PM emission control technologies were identified during the alternative review.

5.2.3 Step 2 – Eliminate Technically Infeasible PM Control Options

During the search of the RBLC listings, Alabama Power observed that the PM control alternative listed for all the natural gas-fired boilers in the "utility- and large industrial-size category" is either the use of natural gas or clean fuels (which inherently have low sulfur content) or good combustion practices; add-on controls for PM are not included in any of these RBLC listings. Similarly, none of the permits for utility units that have converted to natural gas firing since 2014 and that are not listed in the RBLC list add-on PM emission controls as being required for any of these units.

Add-on control alternatives for PM, including ESPs and fabric filters, have never been applied to a utility or commercial scale natural gas-fired boiler. These alternatives are not technically feasible on natural gas-fired boilers because natural gas firing inherently results in a very low level of PM emissions. Specifically, the inlet PM emission concentration from a typical coal-fired utility boiler equipped with either an ESP or baghouse filter is orders of magnitude higher than the projected emissions for Barry Unit 5 when combusting natural gas (equivalent to approximately 0.005 gr/dscf). ESPs and fabric filters are designed for significantly different exhaust gas loadings and not for controlling the low concentrations of PM present in gaseous fuel fired applications. Also, the inapplicability of post-combustion controls for PM is consistent with 40 CFR 60.42(f)(1). Consequently, ESPs and fabric filters are technically infeasible and do not represent available control technologies for natural gas-fired boilers.

Accordingly, the use of clean fuels and good combustion practices are the only technically feasible alternatives for Barry Unit 5.

5.2.4 Step 3 – Rank Remaining PM Control Options

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for PM emissions from Barry Unit 5 when combusting natural gas, and both are proposed as BACT.

5.2.5 Step 4 – Evaluation of PM Control Options

The top control option is being proposed for PM emissions from Barry Unit 5 following its conversion to natural gas firing. Therefore, no further evaluation of the impacts of the PM control options is required.

5.2.6 Step 5 – Select PM BACT for Natural Gas Firing

BACT for PM emissions for the conversion of Barry Unit 5 to natural gas firing is concluded to be based on the use of fuels with an inherently low sulfur content (natural gas fuel) and good combustion practices. Natural gas is inherently a very clean-burning fuel with negligible ash content. Since there are no technically feasible add-on control alternatives for PM for natural gas-fired boilers, good combustion practices (including proper burner design and optimal air-to-fuel ratio control) will ensure the fuel burns completely, minimizing the formation of soot and unburned hydrocarbons that are the principal constituents of PM emissions from natural gas boilers. The combination of using a clean burning fuel and good combustion practices constitutes the most stringent and effective PM control that is technologically feasible for Barry Unit 5.

No minimal level of control "(BACT floor") exists for PM emissions from Barry Unit 5 when firing natural gas as US EPA does not regulate this pollutant under any of the potentially applicable NSPS for natural gas-fired boilers.

In order to identify the emission rate that reflects the application of natural gas firing with good combustion practices at Barry 5, Alabama Power relied on input from the vendor and its review of units in the RBLC, along with other permitted natural gas steam units. Many of the natural gas boilers listed in the RBLC database have a PM emission rate limit consistent with EPA's AP-42 rate for such units; therefore, Alabama Power proposes the same emission limit of 0.0075 lb/MMBtu. Although PM emissions may be lower under some conditions, a lower PM emission limit would not be achievable consistently over all operating conditions for the life of the facility. This is primarily due to the anticipated variability in the natural gas sulfur content and potential for air infiltration or entrainment of residual dust as discussed above. Collectively, these site-specific constraints introduce "uncontrollable fluctuation or variability in the measured emission rate," in other words variations that are independent of the proper application of BACT. Accordingly, a more stringent limit would not reflect the application of BACT to Barry 5.

To confirm this analysis, Alabama Power considered the instances where large steam boilers have been assigned more stringent permitted limits. The RBLC categorizes boilers based on heat input capacity, with boilers having heat inputs greater than 250 MMBtu/hr being identified as "utility- and large industrial-size" boilers. As an initial matter, Barry Unit 5, with a nominal heat input rating greater than 7,000 MMBtu/hr, is much larger than any of the units identified as "large" in the database and is more than an order of magnitude larger than most. Thus, the RBLC review did not provide examples of similar sized boilers for comparing emission rates. Regardless, in order to identify units with potentially similar emission profiles, an advanced search of the RBLC was performed, limiting the results to units with heat input capacities greater than 1,000 MMBtu/hr.

For units permitted in the past fifteen years, the RBLC contains three listings that meet this criterion and those are provided in **Appendix D**, **Table D-1**. All three of these units were permitted by the Louisiana Department of Environmental Quality (LDEQ). Two of these units are permitted at 0.0075 lb/mmBtu, as proposed here, while the third unit has a PM limit set at 0.0057 lb/mmBtu. However, this third unit has not been constructed. Each of these units is discussed below.

On December 20, 2023, LDEQ issued construction and Title V operating permits to Koch Industries for an optimization project at the Koch Methanol facility in St. James Parish, LA. The project includes modifications to an existing natural gas- and process gas-fired steam boiler to increase its heat input capacity from 997 MMBtu/hr to 1100 MMBtu/hr. The RBLC listing for this boiler describes its PM control method as good combustion, and the listing describes the PM emissions limit as 8.2 lb/hr or 0.0075 lb/MMBtu. Koch Methanol announced that the optimization project had been completed in 2024.

LDEQ issued a permit to Big Lake Fuels for a large gas-fired startup boiler in 2019. This boiler would have been part of a methanol manufacturing complex proposed to be located in Lake Charles, LA. The complex was never constructed and in 2024 Big Lake Fuels requested, and the LDEQ granted, recission of this permit.

Finally, LDEQ issued construction and Title V operating permits for the FG LA complex in St. James Parish, LA on January 6, 2020. If constructed, this petrochemical facility (known as the Sunshine Project) will operate three natural gas-fired boilers with heat input capacities of 1200 MMBtu/hr each. The RBLC listing for these boilers describes their PM control method as "natural gas and good combustion." The PM emission limit for each boiler contained in the RBLC listing is 6.81 lb/hr, which is equivalent to an emission rate of 0.0057 lb/MMBtu. Construction of the facility, however, has not yet commenced due to legal challenges to the permits and other delays. Accordingly, the PM emission limit contained in the RBLC listing for these units has not yet been demonstrated. Moreover, even if this rate were to be demonstrated, the boilers at issue are not gas conversions from solid fuel design, which means the potential for residual dust and air infiltration are not comparable to Barry Unit 5.

In addition to the information available from RBLC, publicly available air permits for electric utility generating units that have been converted from coal firing to natural gas firing since 2014 were reviewed. The air permits for a total of thirty-seven (37) such units were identified, encompassing units in a total of ten (10) states. The Units reviewed are provided in **Table D-2** in **Appendix D**.

With respect to emissions levels, all 37 listed units, have either permitted PM emission rates following the conversion at or above 0.0075 lb/mmBtu (often the state general emission PM standard for combustion units), or received no permit limit for PM at all but use the AP-42 rate of 0.0075 lbs/mmBtu for PTE calculations.

The permit for Xcel Energy's Unit 4 at Cherokee Station in Colorado, which was converted to natural gas firing in 2017 has a rated heat input capacity of 3,520 MMBtu/hr and lists a PM emission limit of 0.03 lb/MMBtu. Importantly, however, this limit is not for filterable and condensable particulate matter combined but it is for filterable PM only. Accordingly, this permit does not provide a comparable rate for Barry Unit 5. Consequently, a lower limit would not be achievable under the full range of operating conditions. Therefore, 0.0075 lb/MMBtu may reasonably be concluded as the highest level of control that can be reliably and technically assured for this specific condition in light of the following considerations:

- Existing Equipment Constraints: The physical configuration of Barry Unit 5 as a solid fuel boiler and unit 5's history of operations as a solid fuel boiler limit the unit's ability to reliably demonstrate a lower emissions level.
- Emission Variability: There is uncertainty in the amount of condensable particulate matter (CPM) that will be emitted and variability in the contribution of FPM.
- Lack of Vendor Guarantee: Crucially, the original equipment manufacturer (OEM) has not provided a total PM emissions guarantee for this project. A guarantee would typically assure a specific emission rate, system reliability, and warranty. The absence of this guarantee significantly increases the risk of non-compliance if a lower, more aggressive emission limit were selected as BACT.

5.2.7 PM BACT for Barry Unit 5

Following its conversion to natural gas firing, Barry Unit 5 will control particulate emissions through the use of natural gas and good combustion practices. Accordingly, and in light of the analysis above, APC proposes the following as PM BACT for the conversion of Barry Unit 5 to natural gas firing:

- PM_{10} and $PM_{2.5}$, each including filterable and condensable PM, will be equal to or less than 0.0075 lb/MMBtu HHV, or 56.9 lb/hr, as measured by US EPA Reference Methods 5 and 201A or 202; and
- APC proposes to conduct an initial reference method test after shakedown and startup of the unit following its conversion to natural gas firing.

6.0 Class II Area Air Quality Modeling Analysis Procedures

6.1 Overview

The air quality dispersion modeling analysis was conducted in accordance with ADEM's Draft PSD Air Quality Analysis Modeling Guidelines (ADEM 2025b) and US EPA's Guideline on Air Quality Models (GAQM, which is contained in 40 CFR Part 51, Appendix W) (US EPA 2024a). Modeling methodology was presented in a modeling protocol submitted to ADEM on 30 September 2025 and approved on 14 October 2025. The following sections present the source data modeled, the procedures for assessing ambient air impacts from the proposed Project's emissions and the standards to which the predicted impacts are compared.

The dispersion modeling analysis evaluated compliance with applicable PSD increments and NAAQS for each pollutant subject to PSD review (PM_{10} and $PM_{2.5}$).

The dispersion modeling for this Project evaluated a range of potential operating loads for the converted Unit 5 boiler to determine worst-case ground-level concentrations. Maximum modeled ground-level concentrations from each load scenario were compared to the SILs (see **Table 4-3**). If modeled concentrations are below the applicable SIL, no additional analyses are necessary since, by definition, the pollutants could not cause or contribute to a NAAQS violation or an exceedance of a PSD increment. If modeling indicates that a SIL is exceeded, then a cumulative impact modeling assessment is required to be performed. The results of cumulative modeling would be analyzed for comparison to the NAAQS and PSD increments (see **Table 4-1** and **Table 4-3**), as applicable. As outlined below, the maximum modeled concentrations are below applicable SILs for PM_{10} and $PM_{2.5}$.

All model input and output files have been provided to ADEM via an electronic modeling archive (or equivalent) with the PSD permit application (**Appendix E**) for ADEM's review.

6.2 Unit 5 Modeling Parameters

The air dispersion modeling analysis was conducted as an unobstructed vertical point source emitting through the original Unit 5 600-ft stack using emission rates and flue gas exhaust characteristics (flow rate and temperature) determined for each load scenario for Unit 5 while firing natural gas. Based on current Project design parameters, Alabama Power is applying for a permit that will allow unrestricted operation on a daily basis. Since emission rates and flue gas characteristics for a given operating load vary, data was derived for three load scenarios: full, intermediate, and low. The stack data and emission rates proposed for modeling are provided in **Table 6-1**.

Table 6-1. Unit 5 Stack Parameters and Emission Rates

Load	Exhaust Flow (1)	Exhaust Temperature	Stack Height	Stack Diameter	Emission(2) Rate (lb/hr)
	ACFM	F	ft	ft	$PM_{10}/PM_{2.5}$
Full	2,259,895	273	600	25	56.9
Intermediate	1,783,062	281	600	25	39.3
Low	1,194,700	245	600	25	27.9

1. Stack exhaust characteristics for full and part-load cases were estimated based on vendor predicted data while firing natural gas.
2. Emission rates for full and part load were calculated using the proposed BACT emission rate for $PM_{10}/PM_{2.5}$, equations presented in **Appendix C**, and the estimated heat input as a function of load.

6.3 Model Selection and Options

The suitability of an air quality dispersion model for a particular application is dependent upon several factors. The following selection criteria were evaluated:

- dispersion environment;
- stack height relative to nearby structures;
- local terrain; and
- representative meteorological data.

The US EPA GAQM prescribes a set of approved models for regulatory applications for a wide range of source types and dispersion environments. AERMOD is US EPA's recommended refined dispersion model for simple and complex terrain for receptors within 50 kilometers (km) of a modeled source. In addition, there is representative meteorological data available with suitable data capture for parameters needed to run AERMOD.

As such, based on a review of the factors described in the following sections of this protocol, Alabama Power used the latest version AERMOD (version 24142) (US EPA 2024b) to assess air quality impacts for the Project. AERMOD was run with default model options in the CONTROL pathway. AERMOD was also applied with the rural source option as discussed below and used to assess air quality impacts of PM_{10} and $PM_{2.5}$ at receptors located within approximately 20-25 km of the Project's site.

6.4 Dispersion Environment

The application of AERMOD requires characterization of the local (within 3 km) dispersion environment as either urban or rural based on prevalent land use. According to US EPA modeling guidelines (US EPA 2024a), if more than 50 percent of an area within a 3-km radius of the proposed project site is classified as rural, then a rural modeling application is required. Conversely, if 50% or more of the area is urban, an urban dispersion adjustment can be used.

The ADEM's Draft PSD Air Quality Analysis Modeling Guidelines (ADEM 2025) recommends the use of the Auer scheme to determine the dispersion environment surrounding the Project site. Urban land use types are classified as categories I1, I2, C1, R2, and R3. **Table 6-2** describes these categories and maps them to reasonably equivalent USGS 2024 National Land Cover Database (NLCD) categories. While the Auer method (Auer 1978) and NLCD do not use the same terms to define their categories, the similarities between the five Auer categories and NLCD categories 23 and 24 are apparent. Thus, it is reasonable to classify NLCD categories 23 and 24 as urban land use. **Figure 6-1** displays the 2024 NLCD data superimposed over aerial imagery within 3 km of the Plant.

The NLCD data were processed with US EPA's AERSURFACE processor (version 24142) to determine the different land use types within 3 km of the Plant. AERSURFACE is typically used to process NLCD data for input to AERMET, the AERMOD model's meteorological data processor. In this case, AERSURFACE output in the form of the pixel count for each of NLCD's land use types was used to determine the total pixel count of urban land use types within 3 km.

As noted above, urban land use types were assumed to be NLCD categories 23 and 24: "Developed, Medium Intensity" and "Developed, High Intensity", respectively. The pixel count for these categories were determined and a large majority (>90%) of the 3 km area around the Plant can be classified as rural land use. Thus, AERMOD was not applied with any urban source options. **Table 6-3** provides the pixel counts as reported in the AERSURFACE output along with respective percentages.

Table 6-2. Comparison of Auer and NLCD Land Use Categories

Auer Urban Land Use Categories[(1)]			USGS 2024 NLCD Categories[(2)]	
Type	Use and Structure	Vegetation	Category	Description
R2	Dense single/multi-family	< 30%	23	Developed, Medium Intensity – Areas with a mixture of constructed materials and vegetation. Impervious surfaces account for 50% to 79% of the total cover. These areas most commonly include single-family housing units.
R3	Multi-family, two story	< 35%	24	Developed, High Intensity – Highly developed areas where people reside or
I1	Heavy Industrial	< 5%		

Auer Urban Land Use Categories[1]			USGS 2024 NLCD Categories[2]	
Type	**Use and Structure**	**Vegetation**	**Category**	**Description**
I2	Light/moderate industrial	< 5%		work in high numbers. Examples include apartment complexes, row houses and commercial/industrial. Impervious surfaces account for 80% to 100% of the total cover.
C1	Commercial	< 15%		

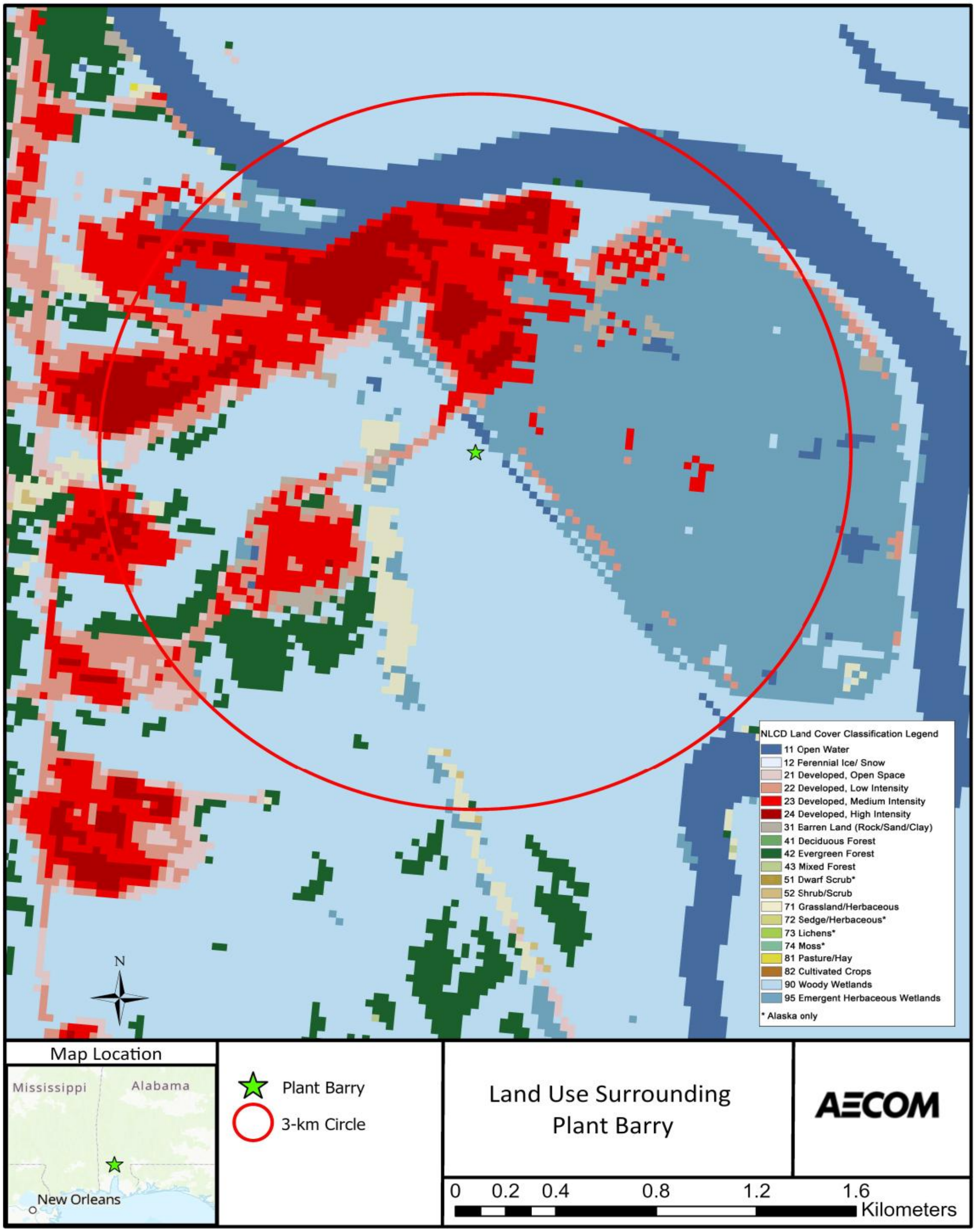
1. US EPA, 2024a.
2. Multi-Resolution Land Characteristics Consortium (MRLC). https://www.mrlc.gov/data/legends/national-land-cover-database-class-legend-and-description

Table 6-3. AERSURFACE Surface Roughness Output

USGS 2024 NLCD Category	Description	Pixel counts	Percent of Total Pixels
0	Missing, Out-of-Bounds, or Undetermined	0	0.00%
11	Open Water	2899	9.23%
12	Perennial Ice/Snow	0	0.00%
21	Developed, Open Space	981	3.12%
22	Developed, Low Intensity	1283	4.08%
23	**Developed, Medium Intensity**	1458	**4.64%**
24	**Developed, High Intensity**	630	**2.01%**
31	Barren Land (Rock/Sand/Clay)	113	0.36%
32	Unconsolidated Shore	0	0.00%
41	Deciduous Forest	0	0.00%
42	Evergreen Forest	2548	8.11%
43	Mixed Forest	9	0.03%
51	Dwarf Scrub	0	0.00%
52	Shrub/Scrub	57	0.18%
71	Grasslands/Herbaceous	1051	3.35%
72	Sedge/Herbaceous	0	0.00%
73	Lichens	0	0.00%
74	Moss	0	0.00%
81	Pasture/Hay	46	0.15%
82	Cultivated Crops	0	0.00%
90	Woody Wetlands	17436	55.50%
91	Palustrine Forested Wetland	0	0.00%
92	Palustrine Scrub/Shrub Wetland	0	0.00%
93	Estuarine Forested Wetland	0	0.00%
94	Estuarine Scrub/Shrub Wetland	0	0.00%
95	Emergent Herbaceous Wetland	2907	9.25%
96	Palustrine Emergent Wetland	0	0.00%
97	Estuarine Emergent Wetland	0	0.00%
98	Palustrine Aquatic Bed	0	0.00%
99	Estuarine Aquatic Bed	0	0.00%
	Total	**31,418**	**100%**

Urban land use types are shown in red, bold text.
Source: AERSURFACE

Figure 6-1. NLCD Land Use



6.5 Terrain

US EPA's GAQM requires that the differences in terrain elevations between the stack base and model receptor locations be considered in the modeling analyses. There are three types of terrain:

- simple terrain – locations where the terrain elevation is at or below the exhaust height of the stacks to be modeled;
- intermediate terrain – locations where the terrain is between the top of the stack and the modeled exhaust "plume" centerline (this varies as a function of plume rise, which in turn, varies as a function of meteorological condition);
- complex terrain – locations where the terrain is above the plume centerline.

The area near the Plant is characterized as consisting of simple terrain relative to the modeled stack.

6.6 Good Engineering Practice Stack Height Analysis

US EPA modeling guidelines require the evaluation of the potential for physical structures to affect the dispersion of emissions from stack emission points. The exhaust from stacks that are located within specified distances of buildings, and whose physical heights are below specified levels, may be subject to "aerodynamic building downwash" under certain meteorological conditions. If this is the case, a model capable of simulating this effect must be employed.

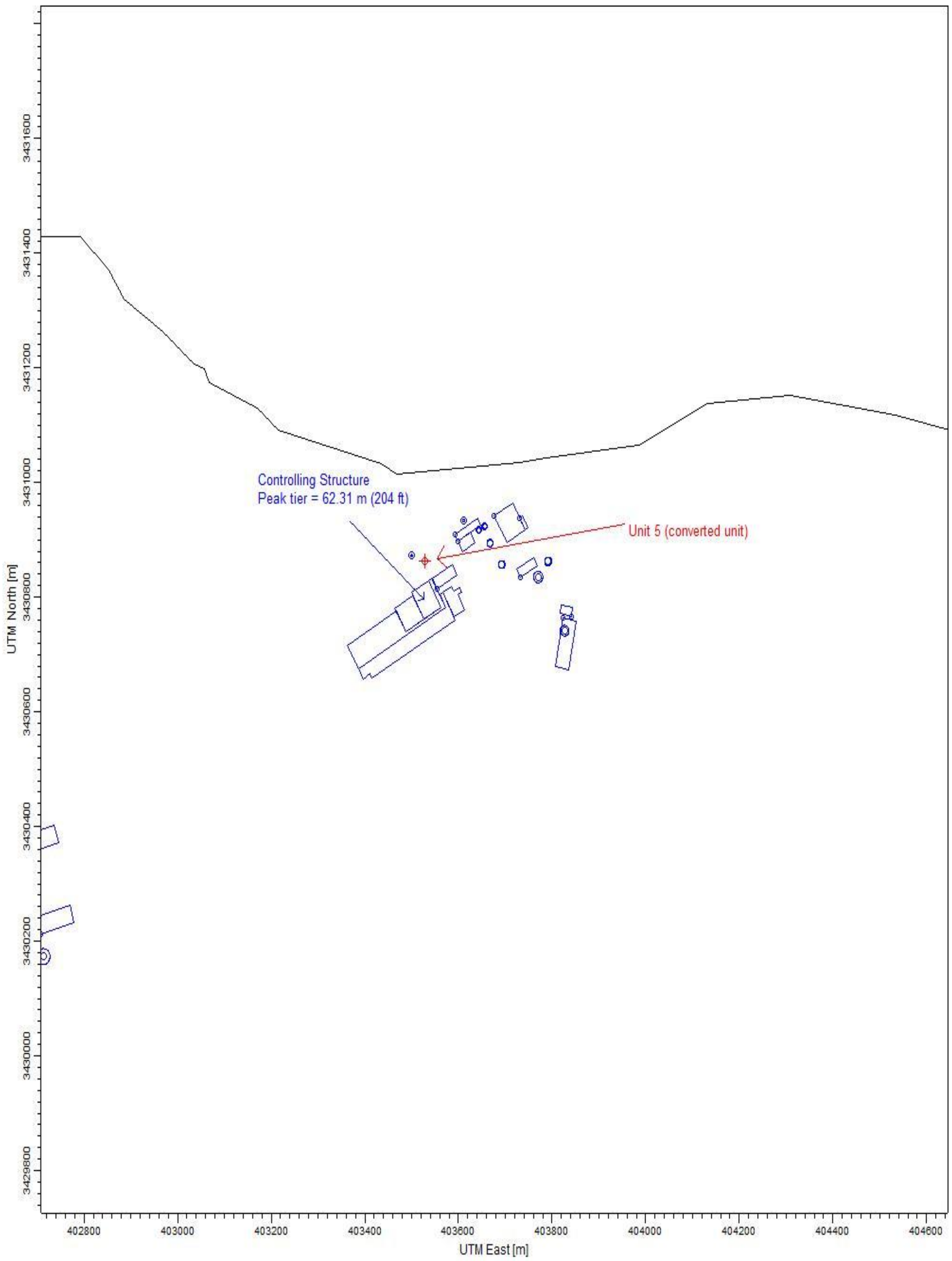
The analysis used to evaluate the potential for building downwash is referred to as a physical "Good Engineering Practice" (GEP) stack height analysis. Stacks with heights below physical GEP are considered to be more influenced by building downwash. In the absence of influencing structures, a "default" GEP stack height is creditable up to 65 meters (213 feet) per the Guideline for Determination of Good Engineering Practice Stack Height (US EPA 1985). Current US EPA guidelines do not allow for modeling of stack heights above the GEP formula stack height unless the stack is "grandfathered", meaning it was in existence on or before December 31, 1970.

The Project source, Barry Unit 5, will be emitting from the original Unit 5 600-ft stack following conversion. The original Unit 5 stack is grandfathered from the GEP Stack Height regulations (i.e., credit for full stack height can be taken in modeling analysis) as construction was completed on the stack in June 1970. This is documented in a letter dated December 11, 1985, from Mr. W. L. Bowers of Alabama Power to Mr. Richard E. Grusnick of ADEM. A copy of this letter is attached in **Appendix F**. Therefore, the dispersion modeling analysis was conducted using the actual stack height of 600 ft.

The US EPA's Building Profile Input Program (BPIP-Version 04274) version that is appropriate for use with PRIME algorithms in AERMOD was used to incorporate wind-direction-specific building dimensions for input to AERMOD. Building coordinates and the stack location were developed using site plan drawings, aerial photographs, and GIS software. All relevant existing building structures (no new buildings are being proposed) were included in the BPIP modeling, as applicable. PRIME addresses the entire structure of the wake, from the cavity immediately downwind of the building, to the far wake.

Figure 6-2 shows existing Plant Barry buildings and the location of the converted Unit 5 stack.

Figure 6-2. Buildings and Sources Included in the BPIP Analysis



6.7 Meteorological Data

The application of a refined dispersion model requires five (5) years of hourly meteorological data representative of the Project site. In addition to being representative, the data must meet quality and completeness requirements per US EPA's GAQM. Per Appendix B of the ADEM's Modeling Guidelines (ADEM 2025), surface data from Mobile Regional Airport in Alabama should be used in the modeling analysis. Mobile Regional Airport is located approximately 25 miles southwest of Plant Barry.

Five (5) contiguous years of data from Mobile Regional Airport, KMOB, (2019-2023) with concurrent upper air data from Slidell Airport in Louisiana, as provided by ADEM, was used in the analysis. The pre-processed meteorological data (profile and surface files) for use with AERMOD was provided by ADEM and was processed with AERMET (Version 24142). The locations of Mobile Regional and Slidell airports relative to the project location are shown **Figure 6-3**. **Figure 6-4** shows a five-year wind rose for Mobile Regional Airport (2019-2023).

Figure 6-3. Location of Met Data Stations Relative to Plant Barry

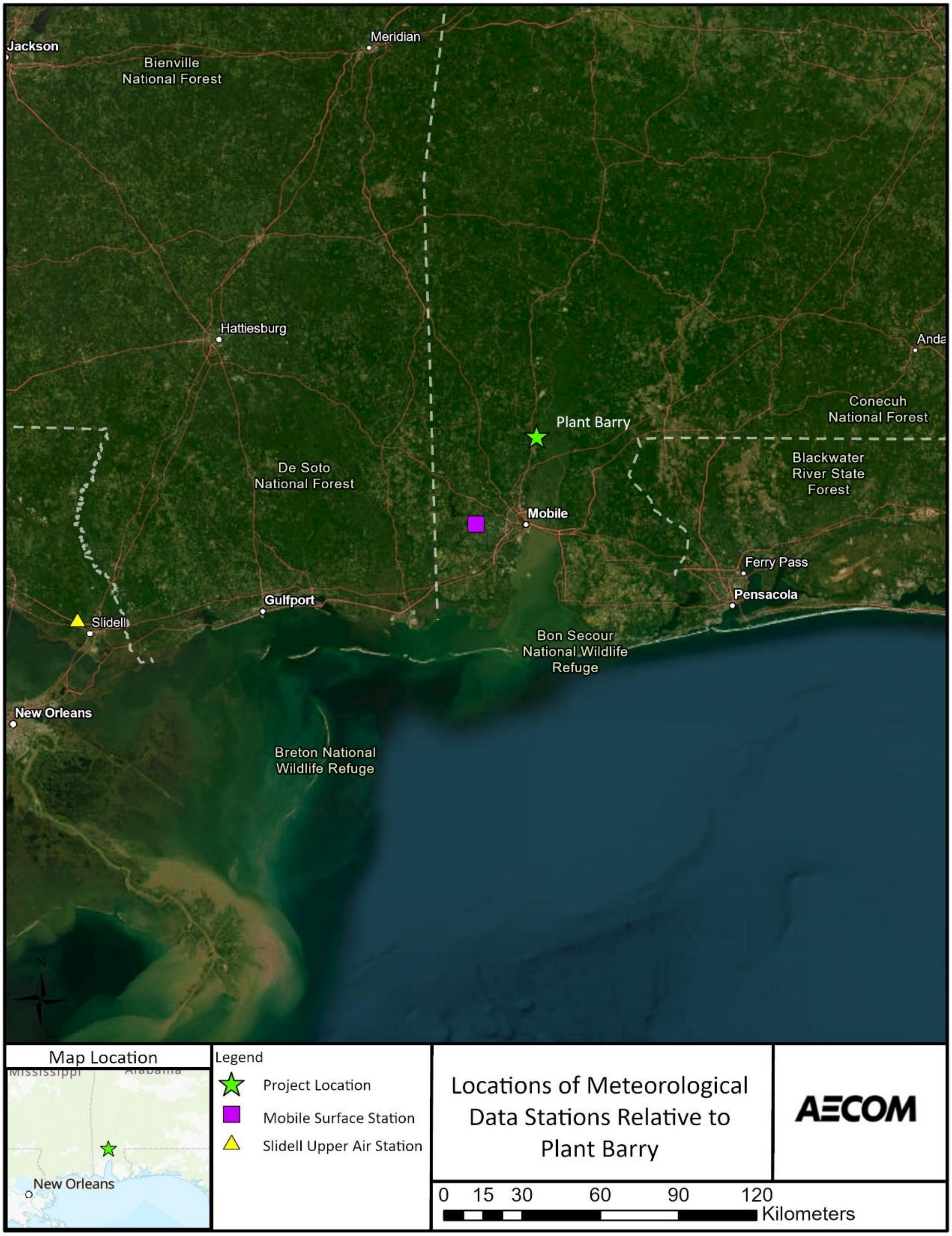
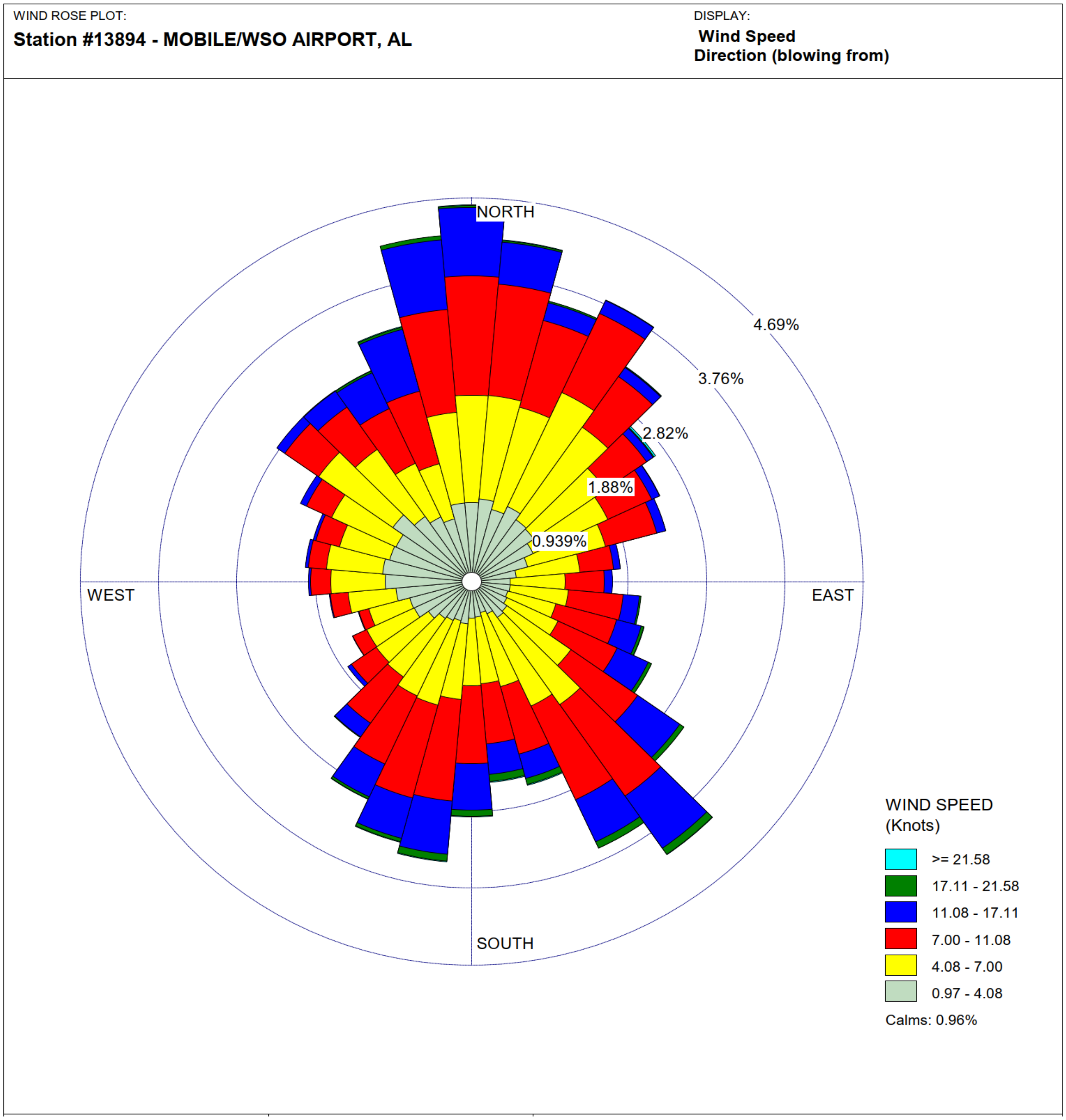


Figure 6-4. Mobile Regional Airport Windrose (2019-2023)



6.8 Receptor Processing with AERMAP

The nested Cartesian receptor grid used in the dispersion modeling analysis consisted of the following receptor spacing:

- From the center of the plant (UTM northing = 3,429,800 meters and UTM easting = 404,100 meters) out to a distance of 4,800 meters (m) at 100-m increments
- Beyond 4,800 m to 6,800 m at 250-m increments
- Beyond 6,800 m to 12,000 m at 500-m increments
- Beyond 12,000 m to 22,500 m (or 20,000 m from the edge of the ambient air boundary) at 1000-m increments

Receptors were also placed at 25-m intervals along the ambient air boundary around Plant Barry, which includes around and to the Ellicott Stone. All maximum modeled concentrations were located within the 100-m spaced receptor grid, thus additional fine grid receptors were not required (see **Figure 7-1**).

Figure 6-5 shows the modeling boundary consisting of fence, swamp land, river and barge canal banks controlled and patrolled areas. Below is a description of the various segments of the ambient air boundary:

- Segment #1 consists in part of the Mobile River bank, thick vegetation, “Private Property, No Trespassing” signs, some fencing, and road access is gated. The gate is locked and requires badge access to open. Additionally, this area is patrolled by plant security personnel, is under direct surveillance by the plant personnel working in the barge canal and is under video surveillance. Therefore, this area of Plant Barry delineated by segment #1 is patrolled and controlled and is not ambient air.
- Segment #2 consists of the interface between the Mobile River and the man-made barge canal. The canal was constructed by Alabama Power for the dedicated use by Plant Barry. Pilings and bulkheads located within this narrow canal act as a physical barrier to other vessels. There are “Private Property, No Trespassing” signs on the river bank at the mouth of the canal. The Plant Barry steam generating units are situated at the mouth of the canal. This area is patrolled and under surveillance – including closed circuit television (CCTV) surveillance of the mouth of the canal and at the barge unloading area – and as such, the area inside the barge canal is not ambient air.
- Segment #3 consists of the Mobile River bank along the existing ash pond and levee. The steep banks of the river, thick vegetation, and the levee are barriers that restrict public access. In addition, a road runs parallel to the river along this segment to the southeast discharge canal and then circles back to the main generating plant building. This road is patrolled by plant security personnel. Therefore, public access to plant areas inside this segment is controlled and patrolled and, as such, this area is not ambient air.
- Segment #4 lies within swamp land that is impassable due to the terrain and vegetation. The area has no roads and is not navigable or accessible to vehicles. Access to this area is additionally restricted by private industrial property, Cold Creek, and the Mobile River. Further, there is “No Trespassing” signage at the river, and steep natural terrain barriers in the area of the transmission line rights-of-way. Therefore, the natural barriers and the absence of roads or paths are sufficient to restrict public access and consider this segment controlled, and as such, the area inside segment #4 is not ambient air.
- Segment #5 outlines an area of thick vegetation along the boundary that inhibits access. The lone access road that can access plant area is the main plant entrance to Unit 8 combined cycle and runs north, adjacent to the ambient air boundary and as such all visitors must pass through plant security. Further, there is CCTV surveillance in this area as well as “Private Property, No Trespassing” signs posted at the gated access point. Therefore, this segment is considered patrolled and controlled, and as such, the area inside segment #5 is not ambient air.
- Segment #6 consists of a small area around the path providing access to the Ellicott Stone historical marker. The Ellicott Stone is a survey boundary marker that was set by Andrew Ellicott when he surveyed the 31st parallel north latitude in 1799. The sandstone boundary marker is protected by a fence and roof covered pavilion. There is public access to the area from Highway 43 along a marked foot pathway leading to the Ellicott Stone. This segment includes fencing and “Private Property, No Trespassing” signs to restrict public access beyond the pathway. Because this segment is controlled with fencing, signage, and surveillance, it establishes the ambient air boundary.
- Segment #7 contains the main plant entrance and contractor gates and as such, all visitors must pass through plant security. Areas of this segment have some fencing and are under surveillance by workers located at Barry Units 6 and 7. Further, there is CCTV surveillance in this area. These factors are sufficient

to consider this area of Plant Barry to be patrolled and controlled. As such, the plant area bounded by segment #7 is not ambient air.

AERMAP (version 24142) (US EPA 2024c), AERMOD terrain preprocessor program, was used to calculate terrain elevations and critical hill heights for the modeled receptors (NAD83 datum and zone 16) using USGS National Elevation Data (NED). The dataset was downloaded using the Lakes Environmental AERMOD View software and consisted of 1/3 arc second (~10 m resolution) NED. As per the AERMAP User's Guide (US EPA, 2024c), the AERMAP domain is sufficient to ensure that all significant nodes are included such that all terrain features that exceed a 10% elevation slope from any given receptor are considered. It is anticipated that the domain will only need to be extended an additional 1.5-km buffer beyond the receptor grid as there are no significant terrain features just beyond this distance. The NED files are referenced to Datum NAD83 (note all source locations and receptors will also be referenced to NAD83 UTM Zone 16). The NED files are included in the modeling archive that is being submitted along with the permit application (**Appendix E**).

The extent of the receptor grid is shown in **Figure 6-6** (near-field) and **Figure 6-7** (far-field).

Figure 6-5. Proposed Ambient Boundary

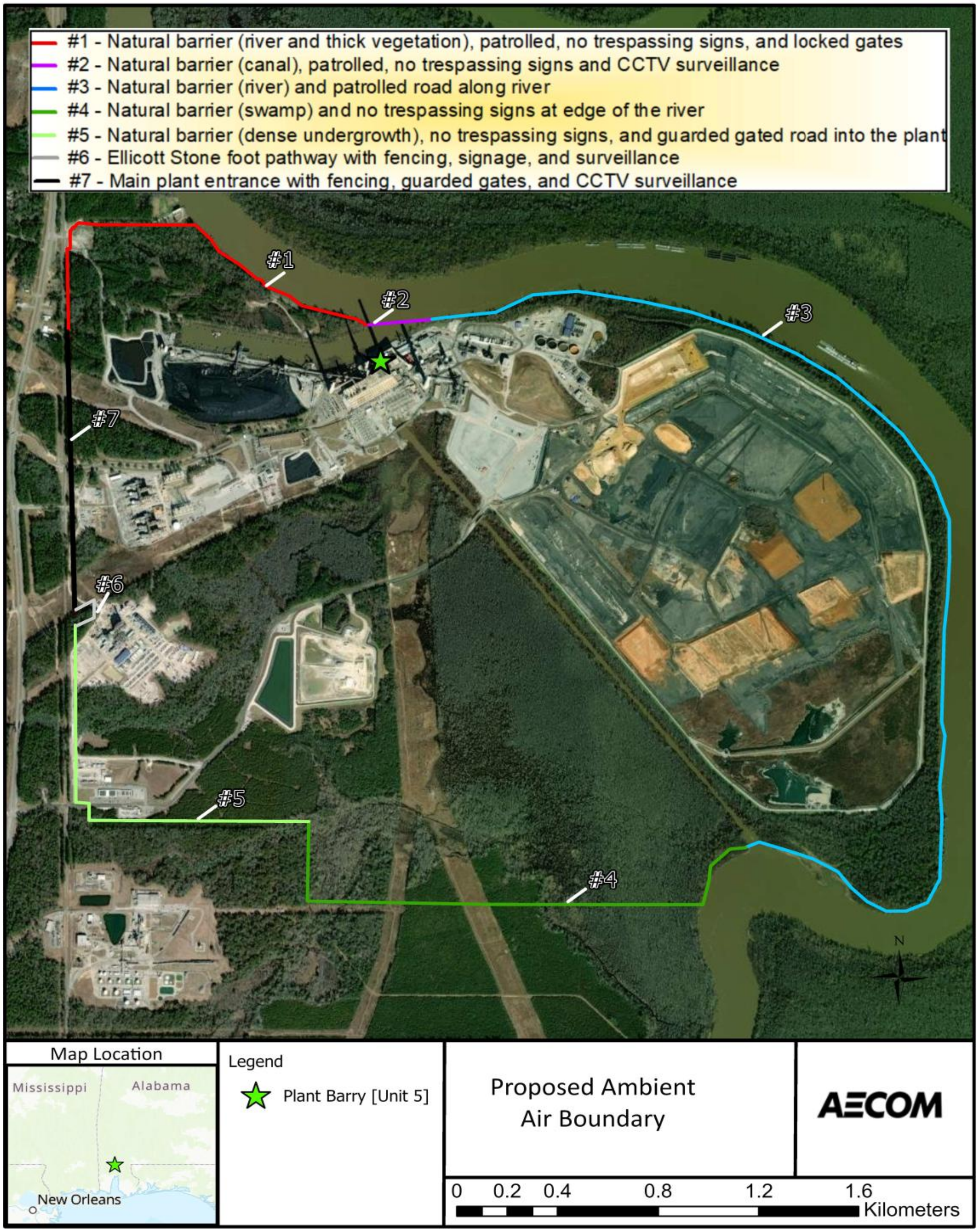


Figure 6-6. Near-field Receptor Grid

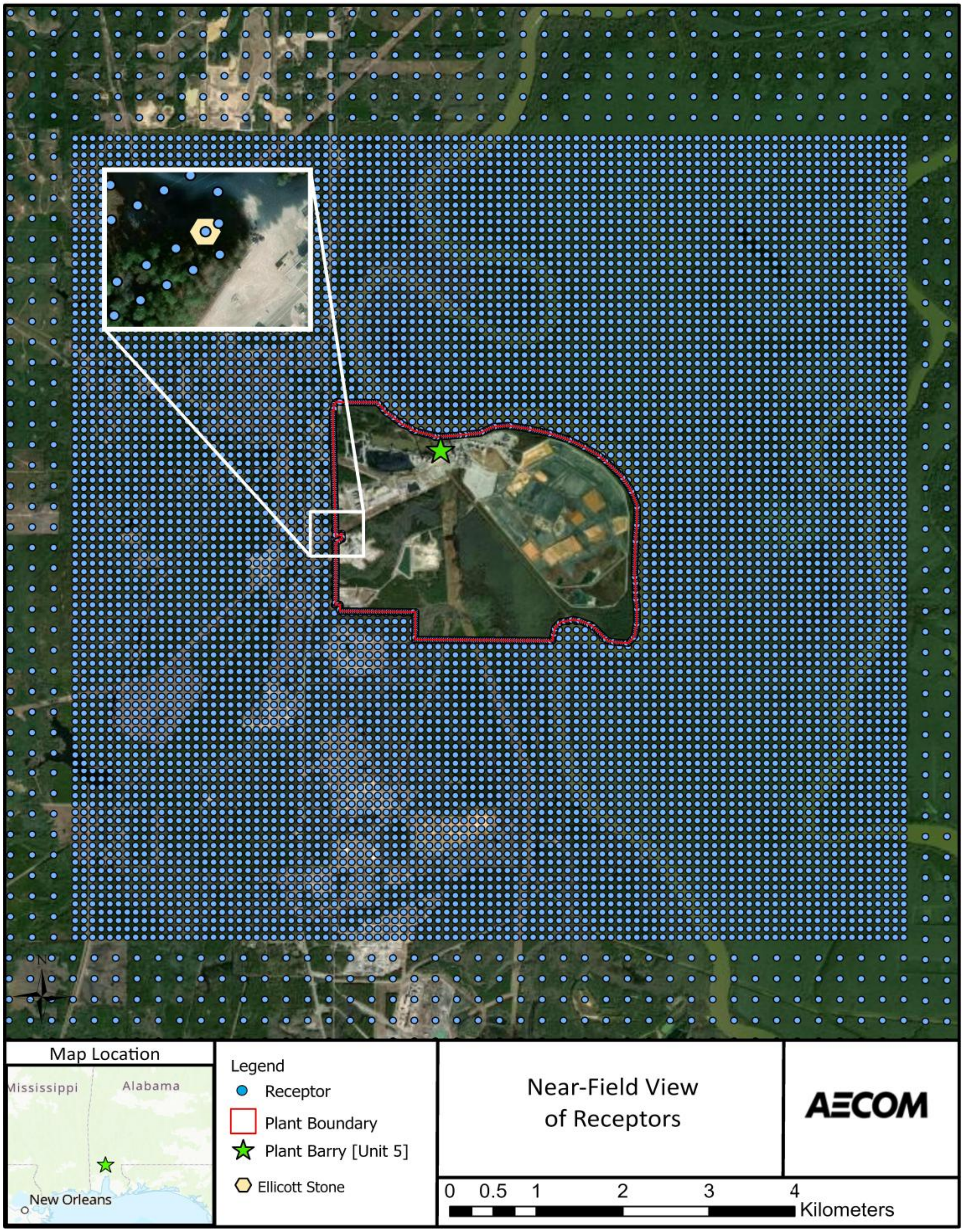
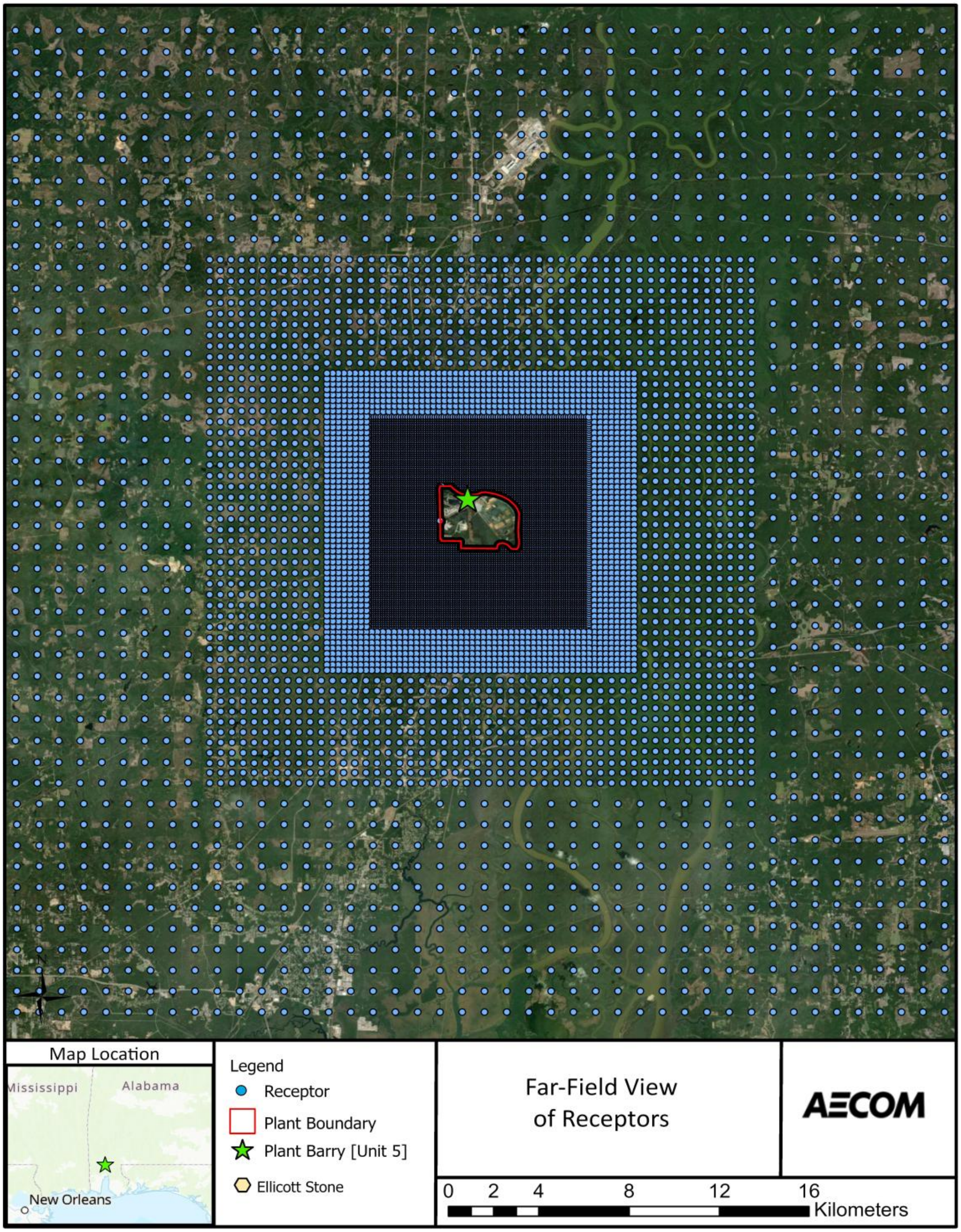


Figure 6-7. Far-field Receptor Grid



6.9 Secondary $PM_{2.5}$

The Project will result in a reduction in emissions of SO_2 and NO_X ($PM_{2.5}$ precursor emissions). Due to these SO_2 and NO_X reductions, the Project's overall impact on secondary $PM_{2.5}$ would be a net benefit (i.e. result in reduction in secondary $PM_{2.5}$) and secondary $PM_{2.5}$ was not accounted for as part of the Project.

7.0 Class II Area Significant Impact Level Analysis Results

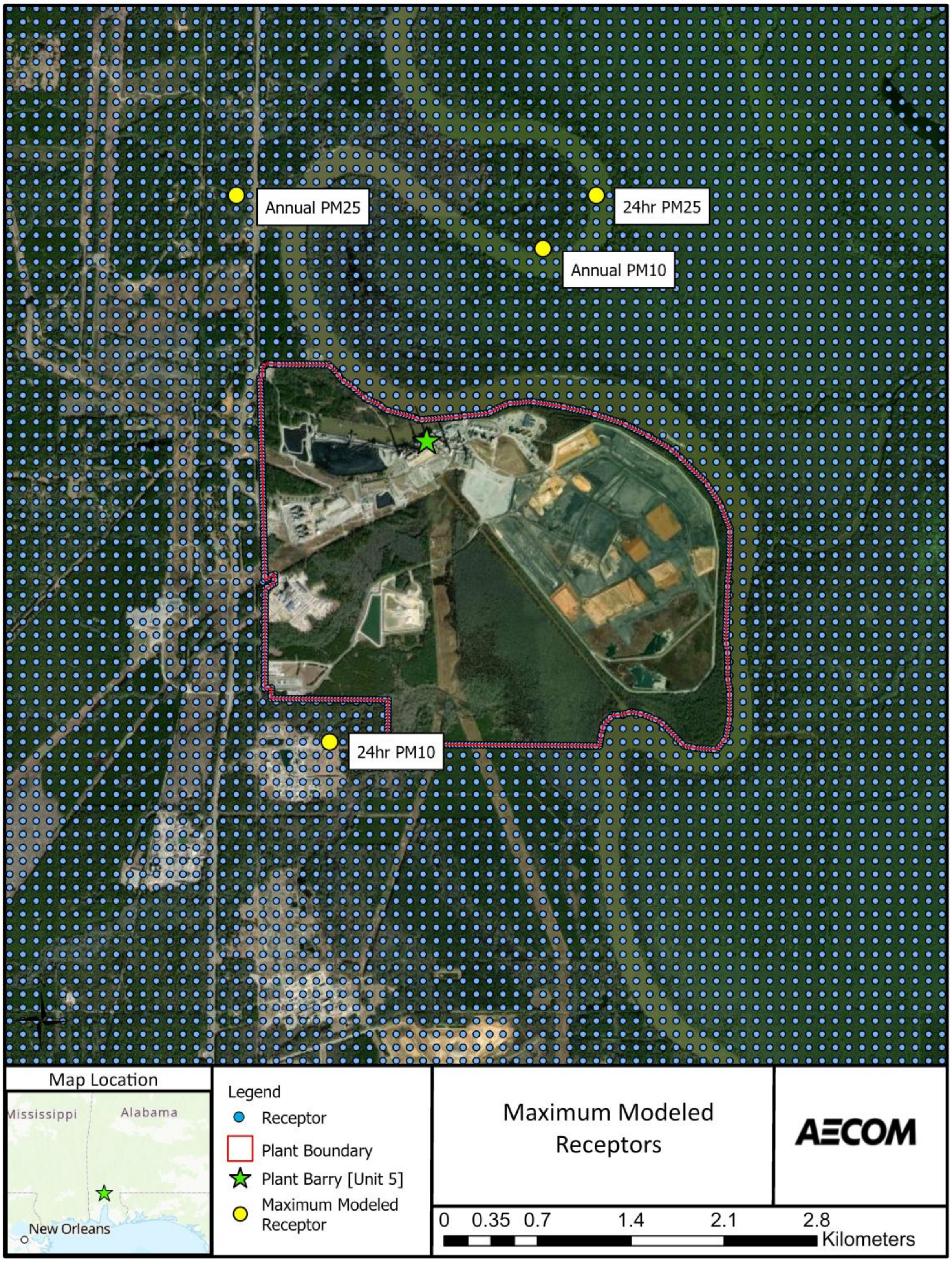
The Class II Area SIL analysis was conducted using five (5) years of airport meteorological data as described in **Section 6**. This modeling analysis was used to make a determination of significance for PM_{10} and $PM_{2.5}$. As noted in **Section 6.2** and **Table 6-1**, since emission rates and flue gas characteristics for a given operating load vary, three (3) load scenarios were modeled: full, intermediate, and low.

For pollutants and averaging periods with modeled concentrations less than their SILs, no further modeling is required because, by definition, those pollutants and averaging periods cannot cause or contribute to a violation of the NAAQS or exceedances of the PSD increments. As shown in **Table 7-1**, maximum modeled concentrations of PM_{10} and $PM_{2.5}$ over all three (3) load scenarios for each averaging period are below their respective SILs and no further modeling is necessary. The scenario that resulted in the maximum modeled concentrations was full load. **Figure 7-1** depicts the locations of each maximum receptor, demonstrating they occur within the 100-m spaced grid.

Table 7-1. Class II SIL Results

Pollutant	Averaging Period	Rank	Maximum Modeled Concentration (µg/m^3)	US EPA SIL (µg/m^3)	Significant? (Yes or No)
PM_{10}	24-hour	H1H	0.32	5.0	No
	Annual	H1H	0.03	1.0	No
$PM_{2.5}$	24-hour	H1H	0.20	1.2	No
	Annual	H1H	0.02	0.13	No

Figure 7-1. Maximum Modeled Receptor



8.0 Other Requirements Potentially Applicable to Construction Permits

8.1 Class I Area Impact Analysis

Federal Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historical perspective. The PSD program provides special protection for such areas. Proposed major new sources and proposed major modifications to existing sources located in the vicinity of a Class I area may need to demonstrate that the PSD Class I increments would not be exceeded, nor would certain air quality-related values (AQRVs) (including visibility) be adversely affected. The closest PSD Class I area to Plant Barry is Breton National Wildlife Refuge (Breton) located approximately 132 km to the southwest.

The Federal Land Managers' Air Quality Related Values Work Group Phase 1 Report (Revised 2010) (FLAG 2010) guidance document, references a Q/D screening approach that is designed to screen out small projects from the need to conduct an AQRV analysis for nearby Class I areas. The Q is defined as the Project short-term emission increases of PM_{10}, SO_2, NOx, and H_2SO_4 expressed in tons. In this case, the "Project" emissions are expressed in terms of the short-term net change in emissions. The D is the distance in kilometers from the source to the Class I area. The FLAG guidance suggests and recent experience/discussions with ADEM indicate that if the Q/D ratio is less than ten, the FLM may decide that an analysis of AQRVs (including regional haze and acid deposition) is not necessary. Alabama Power has included correspondence from the FLM granting a waiver from conducting an AQRV analysis as an attachment in the air permit application (see **Appendix G**).

The total sum of the short-term PM_{10} emissions (Q) firing natural gas is 250 tons per year. This number is the sum of the annualized maximum hourly emissions of PM_{10} from the converted unit: PM_{10} = 56.9 lbs/hr. Emissions of SO_2, NOx, and H_2SO_4 are decreasing due to the Project and are thus not included in the "Q" total. As stated, the closest Class I area is Breton which is located approximately 132 kilometers (D) southwest of Plant Barry. The aforementioned Q and D values result in a Q/D ratio of 1.9. Given this low Q/D ratio, Alabama Power prepared a Request for Applicability of Class I Area Modeling Analysis form that was submitted for review by the FLM to confirm that Class I modeling will not be required. Attached correspondences, **Appendix G**, from FLM confirm Class I modeling is not required.

In addition, previous discussions with ADEM indicated that, because Plant Barry is located more than 100 km from the nearest Class I area (Breton), a Class I increment analysis and NAAQS compliance analysis is not required.

8.2 Soils and Vegetation

The PSD regulations require an evaluation of the impact of project emissions on soils and vegetation. The highest predicted impacts from the Project used in the SIL analysis was compared to the secondary NAAQS to demonstrate the Project does not have an adverse impact on soils and vegetation.

In addition, demonstration of compliance with the 24-hour $PM_{10}/PM_{2.5}$ NAAQS, through modeled concentrations below applicable SILs, also indicates that the Project should not have any nearby impacts associated with visible plumes.

8.3 Growth Related Impacts

Generally, and unless exempted, an application for an Air Permit Authorizing Construction may also be required to conduct a qualitative evaluation of the general commercial, residential, industrial and other growth associated with the Project.

The proposed project is not expected to employ additional employees at this time. Therefore, secondary growth is not expected, and thus an analysis of such growth was not performed.

9.0 References

ADEM, 2025a. Alabama Department of Environmental Management. Air Division – Air Pollution Control Program. Division 335-3. October 2025. ADEM Admin. Code r. 335-3-x-.xx. https://adem.alabama.gov/sites/default/files/2025-10/Division3.pdf

ADEM, 2025b. PSD Air Quality Analysis Modeling Guidelines (June 2025). The Alabama Department of Environmental Management Air Division Planning Branch Meteorological Section. https://adem.alabama.gov/sites/default/files/2025-06/AeromodModelingGuidelines.pdf

Auer, August. 1978. "Correlation of Land Use and Cover with Meteorological Anomalies." Journal of Applied Meteorology, Vol. 17, No.5.

National Park Service, 2010. Phase I Report of the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Revised 2010. National Park Service, Air Resources Division; U.S. Forest Service, Air Quality Program; U.S. Fish and Wildlife Service, Air Quality Branch. http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf.

US EPA 1979. Guidance for Determining BACT Under PSD. United States Environmental Protection Agency Washington, D.C. 20460. https://www.epa.gov/sites/default/files/2015-07/documents/bactupsd.pdf

US EPA 1980. A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals. EPA-450/2-81-078. US EPA, Research Triangle Park, NC 27711.

US EPA 1985. Guideline for the Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) - Revised. EPA-450/4-80-023R, US EPA, Research Triangle Park, NC 27711.

US EPA 1990. New Source Review Workshop Manual. Prevention of Significant Deterioration and Nonattainment Area Permitting. DRAFT OCTOBER 1990. https://www.epa.gov/sites/default/files/2015-07/documents/1990wman.pdf

US EPA 2002. EPA Air Pollution Control Cost Manual. Sixth Edition . EPA/452/B-02-001, January 2002. https://www.epa.gov/sites/default/files/2020-07/documents/c_allchs.pdf

US EPA 2019. Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program. EPA-454/R-19-003, April 2019. https://www.epa.gov/sites/default/files/2020-09/documents/epa-454_r-19-003.pdf

US EPA 2024a. Guideline on Air Quality Models; Enhancements to the AERMOD Dispersion Modeling System. Codified in the Appendix W to 40 CFR Part 51. Office of Air Quality Planning and Standards, Research Triangle Park, NC. November 2024.

US EPA 2024b. AERMOD Implementation Guide. EPA-454-B-24-009, November 2024. US EPA, Research Triangle Park, NC.

US EPA 2024c. User's Guide for the AERMOD Terrain Preprocessor (AERMAP). EPA-454/B-24-008, November 2024. Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2024d. Clarification on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program. April 2024. https://www.epa.gov/sites/default/files/2020-09/documents/epa-454_r-19-003.pdf

Appendix A

Application Forms

ADEM

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
AIR DIVISION ADEM FORM 103

Do not Write in This Space

Facility Number [ ][ ][ ] - [ ][ ][ ][ ]

CONSTRUCTION/OPERATING PERMIT APPLICATION FACILITY IDENTIFICATION FORM

1. Name of Facility or Organization: Alabama Power Company

Plant Name Barry Steam Electric Generating Plant

Facility Physical Location Address

Street & Number: 15300 Highway 43 North

City: Bucks County: Mobile Zip: 36512-0070

Facility Mailing Address (If different from above)

Mailing Contact:

Address or PO Box:

City: State: Zip:

Facility Billing Address

2. Billing Contact: Mike Godfrey

Street & Number: 600 18th Street North

City: Birmingham State: AL Zip: 35203

Telephone Number: 205-257-6131 E-mail Address: jgodfrey@southernco.com

Responsible Official's Business Mailing Address

3. Responsible Official: Mike Godfrey Title: General Manager, Env. Compliance

Street & Number: 600 18th Street North

City: Birmingham State: AL Zip: 35203

Telephone Number: 205-257-6131 E-mail Address: jgodfrey@southernco.com

RO under delegated authority? ☐ Yes ☐ No (if "yes", provide appropriate documentation)

Plant Contact Information

4. Plant Contact: Sandra Bond Title: Specialist Sr, Compliance

Telephone Number: (251) 829-2738 E-mail Address: sbrunson@southernco.com

5. Location Coordinates:				
UTM:	403.372 km E	E-W	3430.685 km N	N-S
Latitude/Longitude:	31°0'20.90"N	LAT	88°0'43.95"W	LONG

6. Permit application is being made to obtain the following type permit:

- ☒ Air permit
- ☐ Major source operating permit
- ☐ Synthetic minor source operating permit

7. Permit application is made for:

- ☐ Existing source (initial application)
- ☐ Existing source (permit renewal)
- ☐ Modification
- ☐ New source (to be constructed)
- ☐ Change of ownership
- ☒ Other (specify) Air Permit

Date construction/modification to begin: October 2026 to be completed: Spring 2028

8. Indicate the number of each of the following forms attached and made a part of this application (if a form does not apply to your operation, indicate "N/A" in the space provided). Multiple forms may be used as required.

1	ADEM 104 INDIRECT HEATING EQUIPMENT
-	ADEM 105 MANUFACTURING OR PROCESSING OPERATION
-	ADEM 106 REFUSE HANDLING, DISPOSAL, AND INCINERATION
-	ADEM 107 STATIONARY INTERNAL COMBUSTION ENGINES
-	ADEM 108 LOADING, STORAGE & DISPENSING LIQUID & GASEOUS ORGANIC COMPOUNDS
-	ADEM 109 VOLATILE ORGANIC COMPOUND SURFACE COATING EMISSION SOURCES
2	ADEM 110 AIR POLLUTION CONTROL DEVICE
-	ADEM 112 SOLVENT METAL CLEANING
-	ADEM 437 COMPLIANCE SCHEDULE
2	ADEM 438 CONTINUOUS EMISSION MONITORS

9. General nature of business: (describe and list appropriate standard industrial classification (SIC) and North American Industry Classification System (NAICS) (www.naics.com) code(s)):

Fossil Fuel Electric Power Generation - NAICS 221112

SIC 4911 - Electric Services

10. Summarize each pollutant emitted and the potential facility-wide annual emission rate for the pollutant. Indicate those pollutants for which the facility is major.

Regulated pollutant	Potential Emissions* (tons/year)	Major source? yes/no
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No
		Yes No

*Potential emissions are either the maximum allowed by the regulations or by permit, or, if there is no regulatory limit, it is the emissions that occur from continuous operation at maximum capacity.

11. Provide a scaled map which contains clearly marked emission points, building locations, property boundaries, and directions (North, etc.). Labeling of emission points should be consistent across all forms.

12. Indicate the compliance status by program for each emission unit or source and the method used to determine compliance. Also cite the specific applicable requirement.

Emission unit or source: ______________________________
(description)

Emission Point No.	Pollutant[4]	Standard	Program[1]	Method used to determine compliance	Compliance Status IN[2]	Compliance Status OUT[3]
					☐	☐
					☐	☐
					☐	☐
					☐	☐
					☐	☐
					☐	☐
					☐	☐
					☐	☐
					☐	☐
					☐	☐
					☐	☐

[1]PSD, non-attainment NSR, NSPS, NESHAP (40 CFR Part 61), NESHAP (40 CFR Part 63), accidental release (112(r)),SIP regulation, Title IV, Enhanced Monitoring, Title VI, Other (specify)

[2]Attach compliance plan

[3]Attach compliance schedule (ADEM Form-437)

[4]Fugitive emissions must be included as separate entries

13. For those applying for a major source operating permit, list all insignificant activities and the basis for listing them as such (i.e., less than the insignificant activity thresholds or on the list of insignificant activities). Attach any documentation needed, such as calculations. No unit subject to an NSPS, NESHAP or MACT standard can be listed as insignificant.

Insignificant Activity	Basis

14. List and explain any facility-wide exemptions from applicable requirements the facility is claiming:

a. See Application

b.

c.

d.

e.

f.

g.

h.

i.

15. List below other attachments that are a part of this application(all supporting engineering calculations must be appended):

a. See Table of Contents

b. Monitoring Plan Diagram

c.

d.

e.

f.

g.

h.

i.

Name of person preparing application: Brittany Pitts

Company of preparer: Alabama Power Company

Phone 334-202-8992 Email: brpitts@southernco.com

Signature: Brittany Pitts Date: 11/12/2025

I CERTIFY UNDER PENALTY OF LAW THAT, BASED ON INFORMATION AND BELIEF FORMED AFTER REASONABLE INQUIRY, THE STATEMENTS AND INFORMATION CONTAINED IN THIS APPLICATION ARE TRUE, ACCURATE AND COMPLETE.

I ALSO CERTIFY THAT THE SOURCE WILL CONTINUE TO COMPLY WITH APPLICABLE REQUIREMENTS FOR WHICH IT IS IN COMPLIANCE, AND THAT THE SOURCE WILL, IN A TIMELY MANNER, MEET ALL APPLICABLE REQUIREMENTS THAT WILL BECOME EFFECTIVE DURING THE PERMIT TERM AND SUBMIT A DETAILED SCHEDULE, IF NEEDED FOR MEETING THE REQUIREMENTS.

Mike Godfrey	GM, Environmental Compliance	11/12/2025
SIGNATURE OF RESPONSIBLE OFFICIAL	TITLE	DATE

ADEM

PERMIT APPLICATION FOR INDIRECT HEATING EQUIPMENT
ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
AIR DIVISION

[ ][ ][ ] - [ ][ ][ ][ ] - [ ][ ][ ][ ]
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1. Name of facility or organization: Alabama Power Company - Barry Steam Electric Generating Plant

2. Unit Description (i.e. No. 1 Power Boiler): Unit 5 Power Boiler

   Source Classification Code(s): 10100212

   Equipment manufacturer's information

   Name of manufacturer: Combustion Engineering

   Model number:

   Rated capacity-input: 7,585 (MMBtu/hr.)

   Boiler type: ☐ Fire Tube ☒ Water Tube ☐ Other (specify):

   Manufactured date:

   Proposed installation date: NG Burner install to be completed in 2028

   Original installation date (if existing): 10/19/1971

   Reconstruction/Modification date (if applicable): Project to be completed in 2028

3. Type of fuel used:

   Primary:

Fuel	Heat Content	Units	Max. % Sulfur	Max. % Ash	Grade No. [fuel oil only]	Supplier [used oil only]
Coal		Btu/lb				
Fuel Oil		Btu/gal				
Natural Gas	1020	Btu/ft^3	Negligible			
L. P. Gas		Btu/ft^3				
Wood		Btu/lb				
Other (specify)						

   Standby:

Fuel	Heat Content	Units	Max. % Sulfur	Max. % Ash	Grade No. [fuel oil only]	Supplier [used oil only]
Coal		Btu/lb				
Fuel Oil		Btu/gal				
Natural Gas		Btu/ft^3				
L. P. Gas		Btu/ft^3				
Wood		Btu/lb				
Other (specify)						

4. Purpose (if multipurpose, note percent in each use category):

- ☐ Space heat ______ %
- ☒ Power generation 100 %
- ☐ Process heat ______ %
- ☐ Other (specify) ______ % ______

5. Normal schedule of operation:

Hours per day: 24 Days per week: 7 Weeks per year: 52

6. For each regulated pollutant, describe any limitations on source operation or any work practice standards which affect emissions:

N/A

7. Are you requesting a limitation for permitting? ☐ Yes ☒ No if "yes", specify the limit and affected unit(s):

8. Is there any emission control equipment on this emission source?

☒ Yes ☐ No (If "yes", ADEM Form 110 must be completed and attached)

9. Stack data (if a control device is installed, the information should be for the control device's stack exit; if multiple stacks associated, provide additional sheet):

Stack No. & Description: 003; Unit 5 Power Boiler Stack Type: V

Stack UTM Coordinate (E-W)	403.528 E	(km)	Stack UTM Coordinate (N-S)	3430.863 N	(km)
Latitude	31°0'26.73"N	(LAT)	Longitude	88°0'38.13"W	(LONG)
Height above grade	600	(ft)	Gas temperature at exit	273	(ºF)
Inside diameter at exit (round)	25	(ft)	Gas Velocity	76.73	(ft/Sec)
Inside area at exit (not round)		(ft^2)	Volume of gas discharged	2,259,895	(ACFM)
Base Elevation	22	(ft)	GEP Stack Height		(ft)

Are sampling ports available? (If "yes", describe. Draw on separate sheet if necessary) ☑ Yes ☐ No :

Is this a merged stack (do multiple units use this release point)? ☐ Yes ☒ No

If yes, provide units:

10. Is this item subject to the Transport Rule 335-3-8-.07 or NOX Budget Program under 335-3-8-.71?

☑ Yes ☐ No If "Yes", provide ORIS Plant and Unit ID: ORISPL: 0003, Unit ID: 5

11. Is this item in compliance with all applicable air pollution rules and regulations?

☑ Yes ☐ No if "No", a compliance schedule, ADEM Form 437, must be attached.)

12. Fugitive Emissions:

POLLUTANT	UNCONTROLLED POTENTIAL EMISSIONS		CONTROLLED POTENTIAL EMISSIONS		BASIS OF CALCULATION	REGULATORY EMISSION LIMIT
	lb/hr	ton/yr	lb/hr	ton/yr		Provide in lb/hr or specify alternative Unit of Measure
Total Particulate						
PM-10 Filterable						
PM-2.5 Filterable						
PM-Condensible						
Sulfur dioxide						
Nitrogen oxides						
Carbon monoxide						
VOC's						

Attach calculation worksheets. Particulate emissions should be speciated to include PM10-filterable, PM2.5-filterable, and PM-condensible. Speciated HAP emissions should also be provided. Attach additional page(s) as necessary.

13. Point Emissions:

POLLUTANT	UNCONTROLLED * POTENTIAL EMISSIONS		CONTROLLED * POTENTIAL EMISSIONS		BASIS OF CALCULATION	REGULATORY EMISSION LIMIT
	lb/hr	ton/yr	lb/hr	ton/yr		Provide in lb/hr or specify alternative Unit of Measure
Total Particulate	56.9	162.0			AP-42	
PM-10 Filterable	14.4	41.0			AP-42	0.12 lb/mmBtu
PM-2.5 Filterable	14.4	41.0			AP-42	0.12 lb/mmBtu
PM-Condensible	42.5	121.0			AP-42	
Sulfur dioxide	4.6	13.0			AP-42 Emission Factor	1.8 lb/mmBtu
Nitrogen oxides			379.3	1079.7	Engineering Estimate	
Carbon monoxide			140.3	399.5	Engineering Estimate	
VOC's			30.5	86.8	Engineering Estimate	

Attach calculation worksheets. Particulate emissions should be speciated to include PM10-filterable, PM2.5-filterable, and PM-condensible. Speciated HAP emissions should also be provided. Attach additional page(s) as necessary.

Name of person preparing application: Brittany Pitts

Company of preparer: Alabama Power Company

Signature: Brittany Pitts

Date: 11/12/2025

*The ton/yr emissions provided in item 13 are projected actual annual emissions and do not represent PTE.

PERMIT APPLICATION FOR AIR POLLUTION CONTROL DEVICE
ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
AIR DIVISION

| | | | - | | | | | - | | | | |

Do not write in this space

1. Name of facility or organization: Alabama Power Company - Barry Steam Electric Generating Plant

2. Type of pollution control device: (if more than one, check each; however, separate forms are to be submitted for each specific device.)

- ☐ Settling chamber
- ☐ Afterburner
- ☐ Cyclone
- ☐ Absorber
- ☐ Condenser
- ☐ Thermal Oxidizer
- ☐ Wet scrubber (kind): ______
- ☒ Other (describe): Oxidation Catalyst
- ☐ Electrostatic precipitator
- ☐ Baghouse
- ☐ Multiclone
- ☐ Adsorber
- ☐ Wet Suppression

3. Control device manufacturer's information:

Name of manufacturer: TBD Model No.: TBD

4. Emission source(s) to which device is installed or is to be installed:

Unit 5 Power Boiler

5. Emission parameters:

	Pollutants Removed		
	Pollutant #1	Pollutant #2	Pollutant #3
	CO	VOC	
Mass emission rate (#/hr)			
Uncontrolled	0.074 lb/mmBtu	0.006 lb/mmBtu	
Designed..			
Manufacturer's guaranteed			
Mass emission rate (Expressed as units of standard)			
Required by regulation..............................			
Manufacturer's guaranteed			
Removal efficiency (%)			
Designed..	75%	33%	
Manufacturer's guaranteed			

6. Gas conditions:

	Inlet	Intermediate Locations	Outlet
Volume (SDCFM, 68ºf, 29.92" hg)			
(ACFM, existing conditions)			2,259,895
Temperature (ºF)			273
Velocity (ft/sec)			76.73
Percent moisture			

Pressure drop across device: ____________ (inches H_2O)

7. Stack dimensions:

Stack No. & Description: Unit 5 Power Boiler Stack Type: V

Stack UTM Coordinate (E-W)	403.528 E	(km)	Stack UTM Coordinate (N-S)	3430.863 N	(km)
Latitude	31°0'26.73"N	(LAT)	Longitude	88°0'38.13"W	(LONG)
Height above grade	600	(ft)	Gas temperature at exit	273	(ºF)
Inside diameter at exit (round)	25	(ft)	Gas Velocity	76.73	(ft/Sec)
Inside area at exit (not round)	N/A	(ft^2)	Volume of gas discharged	2,259,895	(ACFM)
Base Elevation	22	(ft)	GEP Stack Height	600 (grandfathered)	(ft)

Are sampling ports available? (If "yes", describe. Draw on separate sheet if necessary) ■ Yes ☐ No :

Is this a merged stack (do multiple units use this release point)? ☐ Yes ■ No

If yes, provide units:

8. Provide a flow diagram which includes gas exit from process, each control device, location of by-pass, fan or blower, each emission point, exits for collected pollutants, and location of sampling ports.

9. Enclosed are:

☐ Blueprints ☐ Particle size distribution report

☐ Manufacturer's literature ☐ Size efficiency- curves

☐ Emissions test of existing installation ☐ Fan curves

■ Other Enclosed emissions calculations provide further detail

10. If the pollution control device is of unusual design, please provide a sketch of the device.

11. List below the important operating parameters for the device. (For example: air/cloth ratio and fabric type, weight, and weave for baghouse; throat velocity and water use rate for a venturi scrubber; etc.)

12. By-pass (if any) is to be used and when:

13. Disposal of collected air pollutants:

	Solid waste	Solid waste	Liquid waste	Liquid waste
Volume	N/A		N/A	
Composition				
Is waste hazardous?				
Method of disposal				
Final destination				

If collected air pollutants are recycled, describe:

N/A

Name of person preparing application: Brittany Pitts

Company of preparer: Alabama Power Company

Signature: Brittany Pitts Date: 11/12/2025

PERMIT APPLICATION FOR AIR POLLUTION CONTROL DEVICE
ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
AIR DIVISION

			-					-				

Do not write in this space

1. Name of facility or organization: Alabama Power Company - Barry Steam Electric Generating Plant

2. Type of pollution control device: (if more than one, check each; however, separate forms are to be submitted for each specific device.)

- ☐ Settling chamber
- ☐ Afterburner
- ☐ Cyclone
- ☐ Absorber
- ☐ Condenser
- ☐ Thermal Oxidizer
- ☐ Wet scrubber (kind):
- ☒ Other (describe): Selective Catalytic Reduction
- ☐ Electrostatic precipitator
- ☐ Baghouse
- ☐ Multiclone
- ☐ Adsorber
- ☐ Wet Suppression

3. Control device manufacturer's information:

Name of manufacturer: Southern Company Generation Model No.: Custom Design

4. Emission source(s) to which device is installed or is to be installed:

Unit 5 Power Boiler

5. Emission parameters:

	Pollutants Removed		
	Pollutant #1	Pollutant #2	Pollutant #3
	Nitrogen Oxides		
Mass emission rate (#/hr)			
Uncontrolled	0.15 lb/mmBtu		
Designed			
Manufacturer's guaranteed			
Mass emission rate (Expressed as units of standard)			
Required by regulation			
Manufacturer's guaranteed			
Removal efficiency (%)			
Designed	67%		
Manufacturer's guaranteed			

6. Gas conditions:

	Inlet	Intermediate Locations	Outlet
Volume (SDCFM, 68ºf, 29.92" hg)			
(ACFM, existing conditions)			2,259,895
Temperature (ºF)			273
Velocity (ft/sec)			76.73
Percent moisture			

Pressure drop across device: ____________ (inches H_2O)

7. Stack dimensions:

Stack No. & Description: Unit 5 Power Boiler   Stack Type: V

Stack UTM Coordinate (E-W)	403.528 E	(km)	Stack UTM Coordinate (N-S)	3430.863 N	(km)
Latitude	31°0'26.73"N	(LAT)	Longitude	88°0'38.13"W	(LONG)
Height above grade	600	(ft)	Gas temperature at exit	273	(ºF)
Inside diameter at exit (round)	25	(ft)	Gas Velocity	76.73	(ft/Sec)
Inside area at exit (not round)	N/A	(ft^2)	Volume of gas discharged	2,259,895	(ACFM)
Base Elevation	22	(ft)	GEP Stack Height	600 (grandfathered)	(ft)

Are sampling ports available? (If "yes", describe. Draw on separate sheet if necessary) ☒ Yes ☐ No :

Is this a merged stack (do multiple units use this release point)? ☐ Yes ☒ No

If yes, provide units:

8. Provide a flow diagram which includes gas exit from process, each control device, location of by-pass, fan or blower, each emission point, exits for collected pollutants, and location of sampling ports.

9. Enclosed are:

☐ Blueprints
☐ Manufacturer's literature
☐ Emissions test of existing installation
☐ Other ____________
☐ Particle size distribution report
☐ Size efficiency- curves
☐ Fan curves

10. If the pollution control device is of unusual design, please provide a sketch of the device.

11. List below the important operating parameters for the device. (For example: air/cloth ratio and fabric type, weight, and weave for baghouse; throat velocity and water use rate for a venturi scrubber; etc.)

The SCR system consists of a single reactor installed in a vertical flow configuration. The reactor is designed to accommodate up to four catalyst layers, allowing for operational flexibility and optimization of NOx reduction efficiency. Ammonia is injected upstream of the reactor and automatically controlled to maintain the desired NOx emission rate.

12. By-pass (if any) is to be used and when:

The SCR may be by-passed during startup until requisite operating temperature is attained. The SCR may also be by-passed during periods of malfunctions or emergency situations.

13. Disposal of collected air pollutants:

	Solid waste	Solid waste	Liquid waste	Liquid waste
Volume	N/A		N/A	
Composition				
Is waste hazardous?				
Method of disposal				
Final destination				

If collected air pollutants are recycled, describe:

N/A

Name of person preparing application: Brittany Pitts

Company of preparer: Alabama Power Company

Signature: Brittany Pitts Date: 11/12/2025

ADEM

PERMIT APPLICATION FOR CONTINUOUS EMISSION MONITORING SYSTEMS
ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
AIR DIVISION

☐☐☐ - ☐☐☐☐ - ☐☐☐☐
Do not write in this space

1. Name of facility or organization: Alabama Power Company - Barry Steam Electric Generating Plant

2. List pollutant or parameter the continuous emission monitoring system is measuring:

☐ Sulfur dioxide	☐ Carbon monoxide
☐ Nitrogen oxides	☐ Particulates
☐ PM 10	☐ Exhaust temperature
☐ Oxygen	☐ Hydrogen chloride
☐ Pressure	☐ Opacity
■ Carbon dioxide	☐ Temperature
	☐ Exhaust gas
	☐ Primary Chamber
	☐ Secondary Chamber
☐ Total reduced sulfides	☐ Flow Rate
☐ Hydrogen sulfide	☐ VOCs
☐ Other (explain):	

3. CEMS Manufacturer's Information:

   Name of manufacturer: Thermo

   Model number: 42iQ

   Serial number:

4. Data acquisition system to be used (data logger, strip chart, software, etc):

   Name of manufacturer/software: Alabama Power Company

   Serial number: 104

5. Indicate emission source to be monitored and the location of the specific CEM:

   Source to be monitored: Barry Unit 5
   The monitor is located in the CEMS building, and the probe is located in the ductwork.

6. Briefly describe the calibration and operational procedures to be used in operating the CEM (indicate estimate of time lost in calibrating, maintaining, repairing, etc.):

The computer system provides automated daily zero/span checks. No lost time occurs due to the daily zero/span checks. We expect between 2-5% lost time due to repairs and maintenance.

7. Indicate CEM calibration/maintenance schedule:

Calibration/maintenance schedules performed are described in the Quality Assurance Plan. This provides for daily, weekly, quarterly, and annual maintenance. CEMS audits are conducted semi-annually or annually. Other repairs are performed as necessary.

8. Check which program(s) apply to the unit with the monitor:

☐ NSPS ☐ SIP ☐ PSD ☐ BIF

☐ NESHAPS ☒ Acid Rain ☐ RCRA ☐ Enhanced Monitoring

9. Monitor span: From: 0% To: 20%

10. Performance protocol (from Appendix B in 40 CFR Part 60): Performance Specification 3

11. Insitu/dilution extractive/extractive? (type): Dilution-Extractive

12. If dilution extractive, give approximate dilution rate: 100:1

13. Conditioning system? ☑ YES ☐ NO

If yes, what type? Dilution Air Conditioning System

14. Does Appendix F in 40 CFR Part 60 apply? ☑ YES ☐ NO

Name of person preparing application: Brittany Pitts

Company of preparer: Alabama Power

Signature: Brittany Pitts Date: 11/12/2025

ADEM

PERMIT APPLICATION FOR CONTINUOUS EMISSION MONITORING SYSTEMS
ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
AIR DIVISION

			-					-				

Do not write in this space

1. Name of facility or organization: Alabama Power Company - Barry Steam Electric Generating Plant

2. List pollutant or parameter the continuous emission monitoring system is measuring:

☐ Sulfur dioxide
☒ Nitrogen oxides
☐ PM 10
☐ Oxygen
☐ Pressure
☐ Carbon dioxide
☐ Carbon monoxide
☐ Particulates
☐ Exhaust temperature
☐ Hydrogen chloride
☐ Opacity
☐ Temperature
  ☐ Exhaust gas
  ☐ Primary Chamber
  ☐ Secondary Chamber
☐ Total reduced sulfides
☐ Hydrogen sulfide
☐ Other (explain):
☐ Flow Rate
☐ VOCs

3. CEMS Manufacturer's Information:

   Name of manufacturer: Thermo

   Model number: 42iQ

   Serial number:

4. Data acquisition system to be used (data logger, strip chart, software, etc):

   Name of manufacturer/software: Alabama Power Company

   Serial number: 104

5. Indicate emission source to be monitored and the location of the specific CEM:

   Source to be monitored: Barry Unit 5
   The monitor is located in the CEMS building, and the probe is located in the ductwork.

6. Briefly describe the calibration and operational procedures to be used in operating the CEM (indicate estimate of time lost in calibrating, maintaining, repairing, etc.):

The computer system provides automated daily zero/span checks. No lost time occurs due to the daily zero/span checks. We expect between 2-5% lost time due to repairs and maintenance.

7. Indicate CEM calibration/maintenance schedule:

Calibration/maintenance schedules performed are described in the Quality Assurance Plan. This provides for daily, weekly, quarterly, and annual maintenance. CEMS audits are conducted semi-annually or annually. Other repairs are performed as necessary.

8. Check which program(s) apply to the unit with the monitor:

☐ NSPS	☐ SIP	☐ PSD	☐ BIF
☐ NESHAPS	☒ Acid Rain	☐ RCRA	☐ Enhanced Monitoring

9. Monitor span: From: 0 ppm To: 500 ppm

10. Performance protocol (from Appendix B in 40 CFR Part 60): Performance Specification 2

11. Insitu/dilution extractive/extractive? (type): Dilution-Extractive

12. If dilution extractive, give approximate dilution rate: 100:1

13. Conditioning system? ☑ YES ☐ NO

If yes, what type? Dilution Air Conditioning System

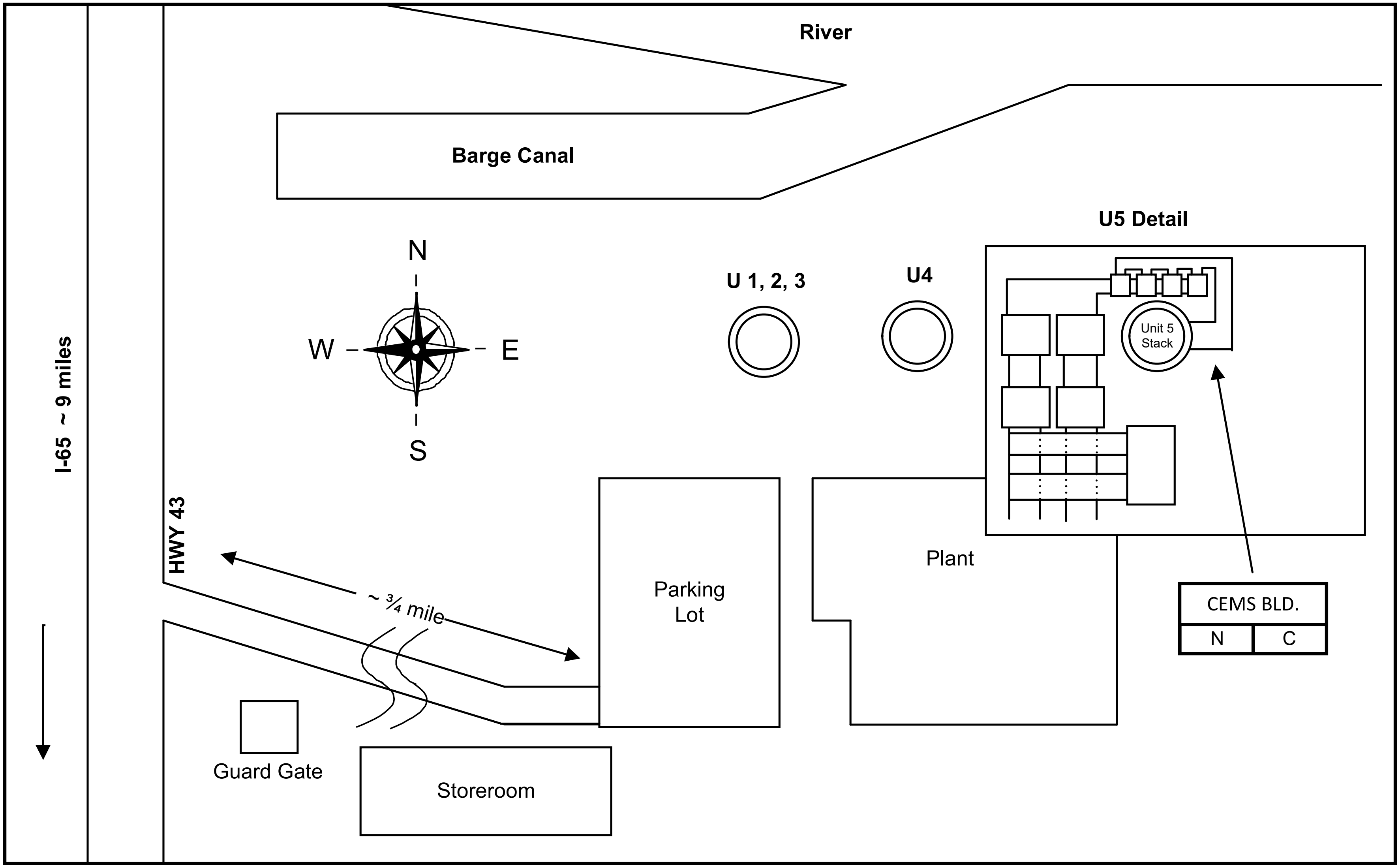
14. Does Appendix F in 40 CFR Part 60 apply? ☑ YES ☐ NO

Name of person preparing application: Brittany Pitts

Company of preparer: Alabama Power

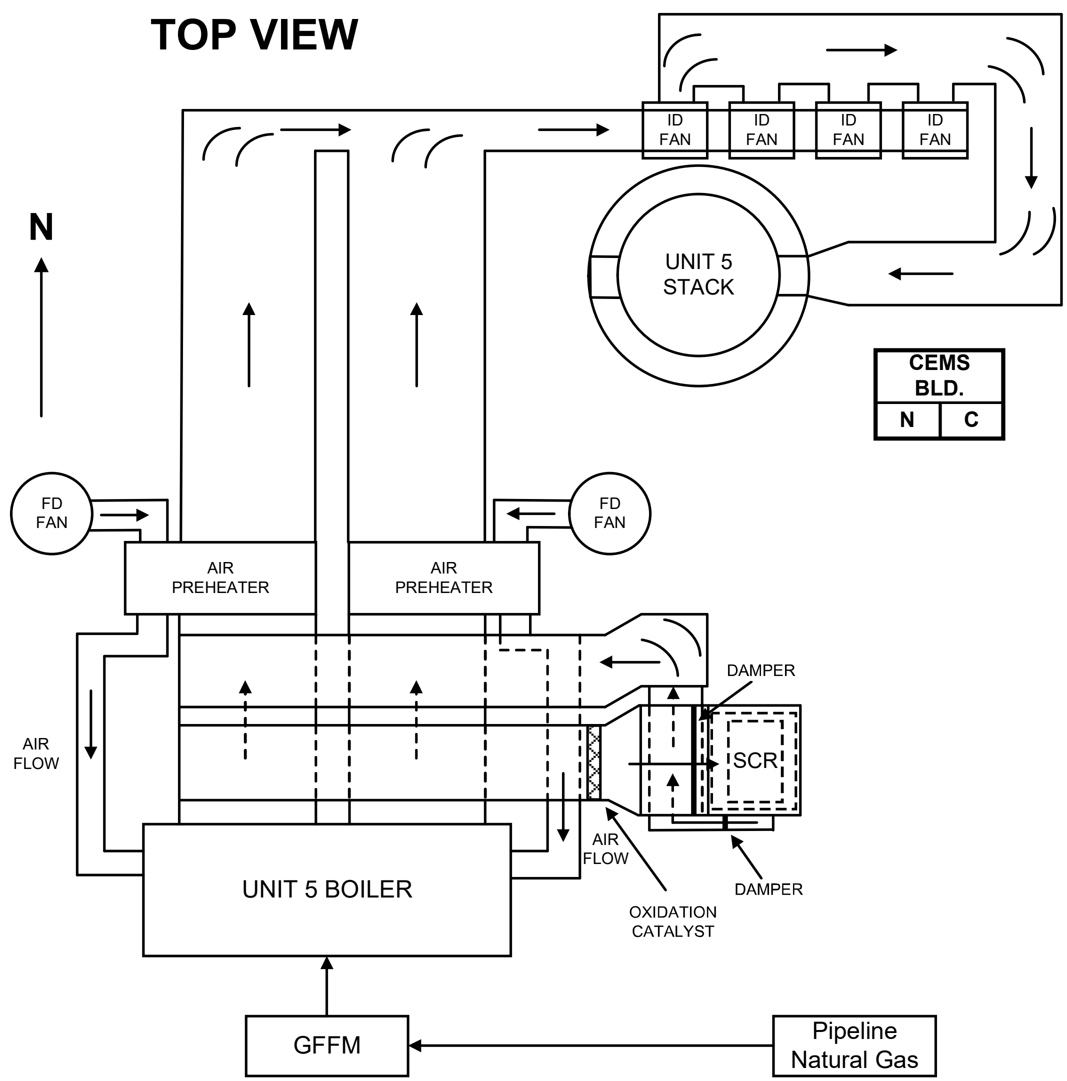
Signature: Brittany Pitts Date: 11/12/2025

Plant Barry ORIS Code 0003
Unit 5 Monitoring System
Monitoring Plan Part 2: Monitor Location Information



ALABAMA POWER COMPANY
BARRY STEAM PLANT
File: Barry 5 Gas MP
Revised: TBD ZMW

Plant Barry Unit 5
Monitoring Plan Part 2: Monitor Location Information
Step 2: Schematic Diagram



UNIT 5 CEMS
STACK ID 5

MONITOR	COMP. ID	SYS. ID
N	TBD	TBD
C	TBD	TBD
PRB	TBD	TBD
GFFM	TBD	TBD

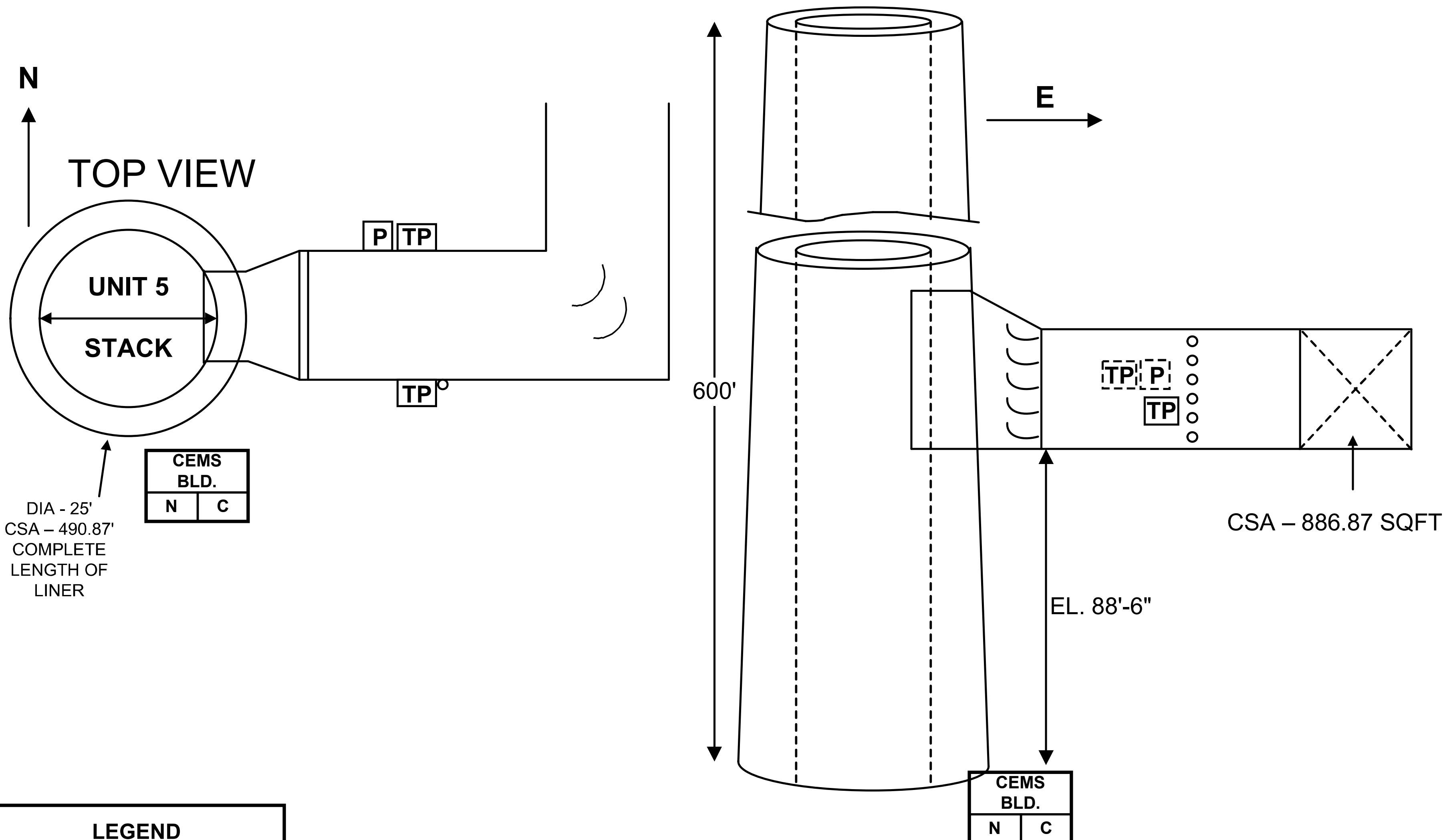
LEGEND

C – CARBON DIOXIDE MONITOR
N – NITROGEN OXIDES MONITOR
GFFM – FUEL FLOWMETER

ALABAMA POWER COMPANY
BARRY STEAM PLANT
File: Barry 5 Gas MP
Revised: TBD ZMW

Unit 5
Monitoring System Information

Plant Barry ORIS Code 0003
Monitoring Plan Part 2: Monitor Location
Information Step 2 – Eng. Drawing Unit 5 – Page 1

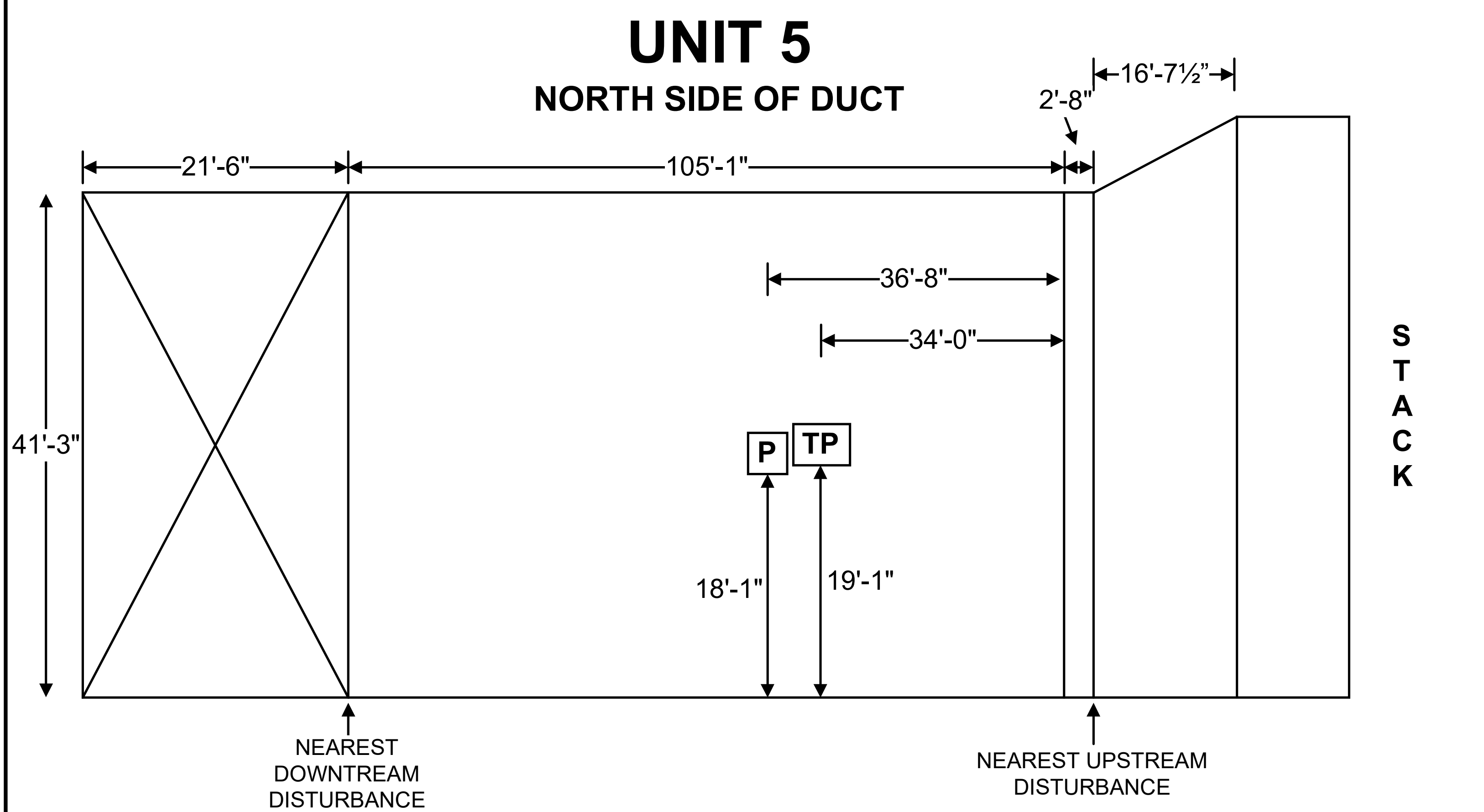


LEGEND

TP – TEST PORTS
o – FLOW TEST PORTS
P – CEMS SAMPLING PROBE
C – CARBON DIOXIDE MONITOR
N – NITROGEN OXIDES MONITOR

ALABAMA POWER COMPANY
BARRY STEAM PLANT
File: Barry 5 Gas MP
Revised: TBD ZMW

Plant Barry ORIS Code 0003
Monitoring Plan Part 2: Monitor Location Information
Step 2 – Eng. Drawing – Unit 5 – Page 2

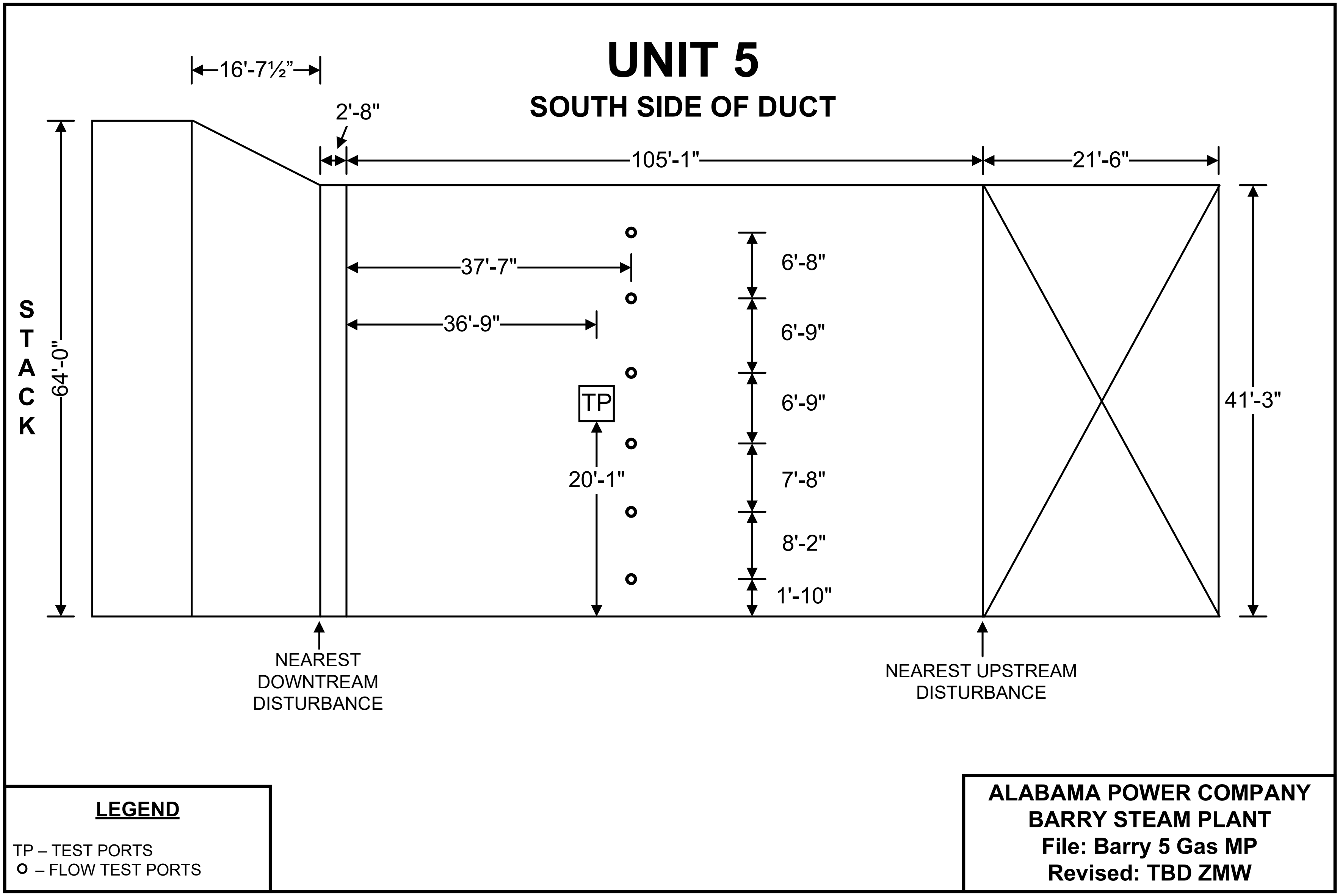


LEGEND

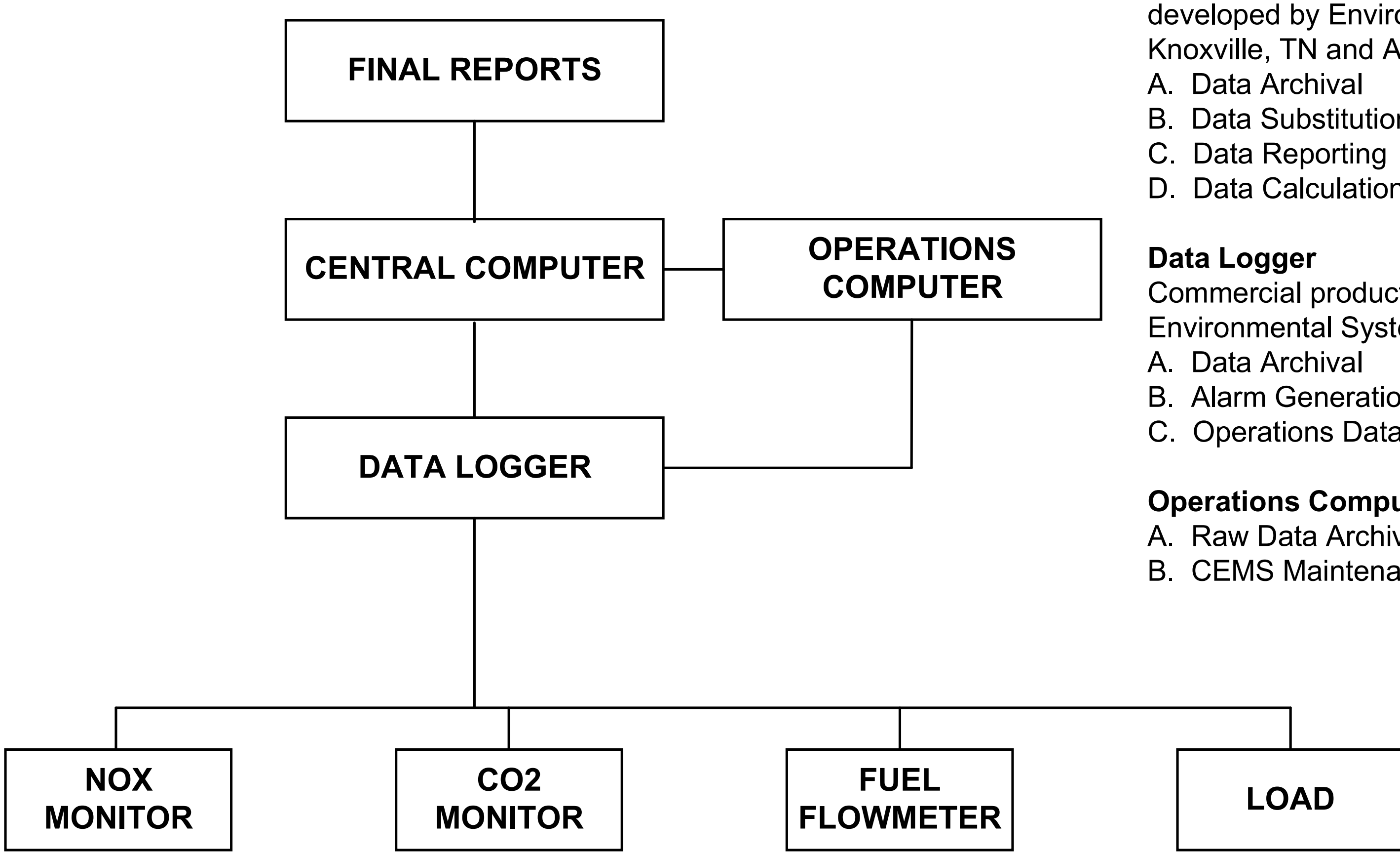
TP – TEST PORT
P - PROBE

ALABAMA POWER COMPANY
BARRY STEAM PLANT
File: Barry 5 Gas MP
Revised: TBD ZMW

Plant Barry ORIS Code 0003
Monitoring Plan Part 2: Monitor Location Information
Step 2 – Eng. Drawing – Unit 5 – Page 3



Barry Unit 5
Data Acquisition and Handling System
per 40 CFR 75.53 (e)(2)(iii)



Software Description
per 40 CFR 75.53 (e) (1) (v)

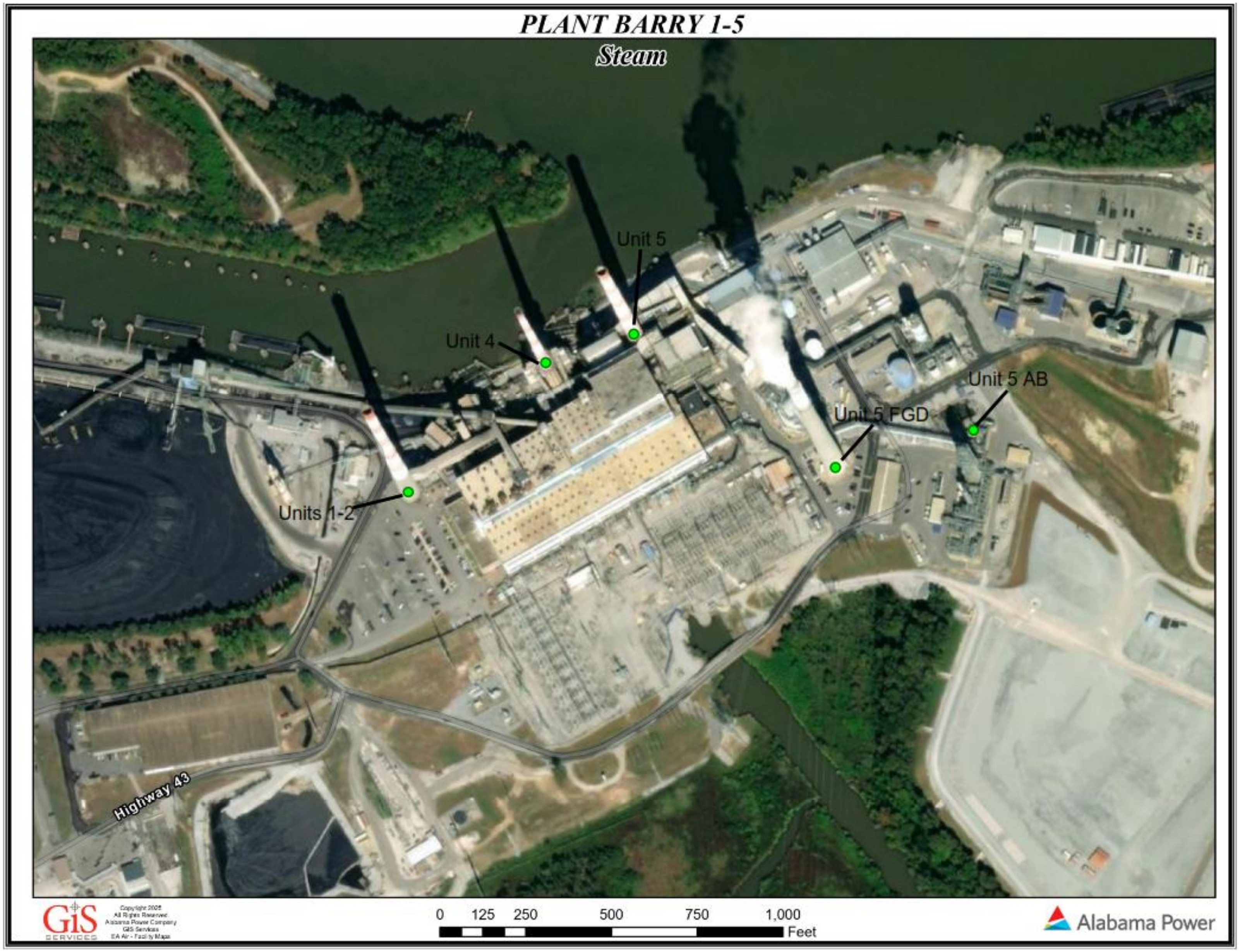
Central Computer
Microsoft NT System with custom/commercial software developed by Environmental Systems Corporation, Knoxville, TN and Alabama Power Company.
A. Data Archival
B. Data Substitution
C. Data Reporting
D. Data Calculations

Data Logger
Commercial product with software developed by Environmental Systems Corporation.
A. Data Archival
B. Alarm Generation
C. Operations Data

Operations Computer
A. Raw Data Archival and Reporting
B. CEMS Maintenance Tools

Appendix B

Plot Plan


PLANT BARRY 1-5
Steam
Unit 5
Unit 4
Units 1-2
Unit 5 FGD
Unit 5 AB
Highway 43
0
125
250
500
750
1,000
Feet
Alabama Power

Appendix C

Emission Calculations

The equations utilized for calculating NSR pollutant and HAP emissions are as follows (this equation is used for both full and part-load $PM_{10}/PM_{2.5}$ emission estimates):

$$E_H \left(\frac{lb}{hr}\right) = HI \left(\frac{mmBtu}{hr}\right) * ER \left(\frac{lb}{mmBtu}\right)$$

$$E_A \left(\frac{tons}{yr}\right) = ER \left(\frac{lb}{mmBtu}\right) * P \left(\frac{mmBtu}{yr}\right) * \left(\frac{1\ ton}{2000\ lb}\right)$$

Where:
E_H = pollutant emissions (lb/hr)
E_A = pollutant emissions (tons/yr)
HI = nominal unit rated heat input of 7,585 mmBtu/hr
HI ($PM_{10}/PM_{2.5}$) = estimated intermediate load unit heat input of approximately 5,239 mmBtu/hr
HI ($PM_{10}/PM_{2.5}$) = estimated low load unit heat input of approximately 3,723 mmBtu/hr
ER = pollutant emission rate in lb/mmBtu
P = highest projected 12-month heat input of unit following project

The equations utilized for each GHG pollutant is as follows:

$$E_H \left(\frac{lb}{hr}\right) = HI \left(\frac{mmBtu}{hr}\right) * EF \left(\frac{kg}{mmBtu}\right) * \left(\frac{2.20462\ lb}{1\ kg}\right) * GWP$$

$$E_A \left(\frac{tons}{yr}\right) = EF \left(\frac{kg}{mmBtu}\right) * \left(\frac{2.20462\ lb}{1\ kg}\right) * P \left(\frac{mmBtu}{yr}\right) * \left(\frac{1\ ton}{2000\ lb}\right) * GWP$$

Where:
E_H = pollutant emissions (lb/hr)
E_A = pollutant emissions (tons/yr)
HI = nominal unit rated heat input of 7,585 mmBtu/hr
EF = GHG emission factor for natural gas in kg/mmBtu (CO_2 = 53.06, CH_4=0.001, N_2O= 0.0001)
P = highest projected 12-month heat input of unit following project
GWP = Global Warming Potential to convert to CO_2e (CO_2 = 1, CH_4 = 28, N_2O=265)

Appendix D

Search Results from EPA's RACT/BACT/LAER Clearinghouse and Listing of Other Similar Units

Appendix D, Table D-1
Natural Gas-Fired Boilers Greater Than 250 MMBtu/hr, Listings for Particulate Matter
Permit Dates From 8/16/2011 Through 6/23/2025

RBLC ID	Facility Name	Facility State	Permit Issuance Date	Process Name	Throughput	Pollutant	Control Method Description	Emissions Limit
*IL-0137	MARQUIS CARBON CAPTURE LLC	IL	6/23/2025	Gas-Fired Boilers	395 MMBtu/hr	Total PM2.5	Energy efficient design (economizer, flue gas recovery, boiler blowdown heat recovery, condensate recovery, steam air preheater); good combustion practices; good burner design capable of proper mixing of air and fuel; automated combustion management system.	0.0040 lb/MMBtu
*IL-0137	MARQUIS CARBON CAPTURE LLC	IL	6/23/2025	Gas-Fired Boilers	395 MMBtu/hr	Total PM10	Energy efficient design (economizer, flue gas recovery, boiler blowdown heat recovery, condensate recovery, steam air preheater); good combustion practices; good burner design capable of proper mixing of air and fuel; automated combustion management system.	0.0052 lb/MMBtu
*LA-0401	KOCH METHANOL (KME) FACILITY	LA	12/20/2023	BLR - Auxilary Boiler	1100 MMBtu/hr	Total PM2.5	The use of good combustion and the use of Selective Catalytic Reduction	0.0075 lb/MMBtu
*LA-0401	KOCH METHANOL (KME) FACILITY	LA	12/20/2023	BLR - Auxilary Boiler	1100 MMBtu/hr	Total PM10	The use of good combustion and the use of Selective Catalytic Reduction	0.0075 lb/MMBtu
*LA-0394	GEISMAR PLANT	LA	12/12/2023	01-22 - AO-5 Boiler	350 MMBtu/hr	Total PM10	Use of proper burner design and fuel specifications	0.0070 lb/MMBtu
*LA-0394	GEISMAR PLANT	LA	12/12/2023	01-22 - AO-5 Boiler	350 MMBtu/hr	Total PM2.5	Use of proper burner design and fuel specifications	0.007 lb/MMBtu
LA-0364	FG LA COMPLEX	LA	1/6/2020	Boilers	1200 MMBtu/hr	Total PM10	Use of pipeline quality natural gas or fuel gas and good combustion practices.	0.0057 lb/MMBtu
LA-0364	FG LA COMPLEX	LA	1/6/2020	Boilers	1200 MMBtu/hr	Total PM2.5	Use of pipeline quality natural gas or fuel gas and good combustion practices.	0.0057 lb/MMBtu
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	KS	10/30/2019	New Boiler	360.2 MMBtu/hr	Total PM10	Ultra Low NOx Burners	0.0075 lb/MMBtu
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	KS	10/30/2019	New Boiler	360.2 MMBtu/hr	Total PM2.5	Ultra Low NOx Burners	0.0075 lb/MMBtu
MI-0440	MICHIGAN STATE UNIVERSITY	MI	5/22/2019	EUSTMBOILER	300 MMBtu/hr	Total PM10	Good combustion practices	0.0077 lb/MMBtu
MI-0440	MICHIGAN STATE UNIVERSITY	MI	5/22/2019	EUSTMBOILER	300 MMBtu/hr	Total PM2.5	Good combustion practices	0.0077 lb/MMBtu
LA-0382	BIG LAKE FUELS METHANOL PLANT	LA	4/25/2019	Utility Boilers (EQT0037, EQT0038)	300 MMBtu/hr	Total PM10	Proper burner design	0.0075 lb/MMBtu
LA-0382	BIG LAKE FUELS METHANOL PLANT	LA	4/25/2019	Utility Boilers (EQT0037, EQT0038)	300 MMBtu/hr	Total PM2.5	Proper burner design	0.0075 lb/MMBtu
LA-0382	BIG LAKE FUELS METHANOL PLANT	LA	4/25/2019	Startup Boiler F343B (EQT0048)	1335.7 MMBtu/hr	Total PM10	Proper burner design and operation	0.0075 lb/MMBtu
LA-0382	BIG LAKE FUELS METHANOL PLANT	LA	4/25/2019	Startup Boiler F343B (EQT0048)	1335.7 MMBtu/hr	Total PM2.5	Proper burner design and operation	0.0075 lb/MMBtu
*TN-0163	HOLSTON ARMY AMMUNITION PLANT	TN	10/8/2018	Four Boilers, Natural Gas & No. 2 Oil-Fired	327 MMBtu/hr, each boiler	Total particulate matter (TPM)		0.1000 lb/MMBtu
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Inline Boilers (4)	258 MMBtu/hr	Total PM10	Clean Fuels, Good combustion practices	0.0075 lb/MMBtu
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Inline Boilers (4)	258 MMBtu/hr	Total PM2.5	Clean Fuels, Good combustion practices	0.0075 lb/MMBtu
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 - Boiler 1 (EQT0003)	350 MMBtu/hr	Total PM10	Good Combustion Practices & Use Pipeline Quality Natural Gas	0.0050 lb/MMBtu
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 - Boiler 1 (EQT0003)	350 MMBtu/hr	Total PM2.5	Good combustion practices & Use pipeline quality natural gas	0.0050 lb/MMBtu
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 - Boiler 2 (EQT0004)	350 MMBtu/hr	Total PM10	Good Combustion Practices & Use Pipeline Quality Natural Gas	0.0050 lb/MMBtu
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 - Boiler 2 (EQT0004)	350 MMBtu/hr	Total PM2.5	Good Combustion Practices & Use Pipeline Quality Natural Gas	0.0050 lb/MMBtu
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Package Boilers (2 identical, B003 and B004)	265 MMBtu/hr	Total PM10	good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing)	0.0075 lb/MMBtu
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Package Boilers (2 identical, B003 and B004)	265 MMBtu/hr	Total PM2.5	good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing)	0.0075 lb/MMBtu
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	No. 9 Boiler - Natural Gas Fired	325 MMBtu/hr	Total PM10	Good combustion practices and Boiler MACT	0.0075 lb/MMBtu
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	No. 9 Boiler - Natural Gas Fired	325 MMBtu/hr	Total PM2.5	Good combustion practices and Boiler MACT	0.0075 lb/MMBtu
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	No. 10 Boiler - Natural Gas Fired	325 MMBtu/hr	Total PM10	Good combustion practices and Boiler MACT	0.0075 lb/MMBtu
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	No. 10 Boiler - Natural Gas Fired	325 MMBtu/hr	Total PM2.5	Good combustion practices and Boiler MACT	0.0075 lb/MMBtu
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	BOILER 2	271 MMBtu/hr	Total PM10	GOOD COMBUSTION PRACTICES	0.005 lb/MMBtu
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Boiler	864 MMBtu/hr	Total PM10	good combustion practices	0.0024 lb/MMBtu
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Boiler	864 MMBtu/hr	Total PM2.5	good combustion practices	0.0010 lb/MMBtu
OK-0162	ENID NITROGEN PLANT	OK	5/29/2014	Boiler	450 MMBtu/hr	Total PM10	Natural Gas Fuel	0.0076 lb/MMBtu
OK-0162	ENID NITROGEN PLANT	OK	5/29/2014	Boiler	450 MMBtu/hr	Total PM2.5	Natural Gas Fuel	0.0076 lb/MMBtu
*LA-0315	G2G PLANT	LA	5/23/2014	Utility Boiler 1	656 MMBtu/hr	Total PM10	Combustion Controls (proper burner design and operation using natural gas)	0.0075 lb/MMBtu
*LA-0315	G2G PLANT	LA	5/23/2014	Utility Boiler 1	656 MMBtu/hr	Total PM2.5	Combustion Controls (proper burner design and operation using natural gas)	0.0075 lb/MMBtu
*LA-0315	G2G PLANT	LA	5/23/2014	Utility Boiler 2	656 MMBtu/hr	Total PM10	Combustion controls (proper burner design and operation using natural gas)	0.0075 lb/MMBtu
*LA-0315	G2G PLANT	LA	5/23/2014	Utility Boiler 2	656 MMBtu/hr	Total PM2.5	Combustion controls (proper burner design and operation using natural gas)	0.0075 lb/MMBtu

Appendix D, Table D-1
Natural Gas-Fired Boilers Greater Than 250 MMBtu/hr, Listings for Particulate Matter
Permit Dates From 8/16/2011 Through 6/23/2025

RBLC ID	Facility Name	Facility State	Permit Issuance Date	Process Name	Throughput	Pollutant	Control Method Description	Emissions Limit
*LA-0315	G2G PLANT	LA	5/23/2014	Utility Boiler 3	656 MMBtu/hr	Total PM10	Combustion controls (proper burner design and operation using natural gas)	0.0075 lb/MMBtu
*LA-0315	G2G PLANT	LA	5/23/2014	Utility Boiler 3	656 MMBtu/hr	Total PM2.5	Combustion controls (proper burner design and operation using natural gas)	0.0075 lb/MMBtu
ID-0021	MAGNIDA	ID	4/21/2014	PACKAGE BOILER	275 MMBtu/hr (HHV)	Total PM10		0.0075 lb/MMBtu
ID-0021	MAGNIDA	ID	4/21/2014	PACKAGE BOILER	275 MMBtu/hr (HHV)	Total PM2.5		0.0075 lb/MMBtu
WY-0074	GREEN RIVER SODA ASH PLANT	WY	11/18/2013	Natural Gas Package Boiler	254 MMBtu/hr	Total particulate matter (TPM)	good combustion practices	0.0070 lb/MMBtu
NE-0054	CARGILL, INCORPORATED	NE	9/12/2013	Boiler K	300 MMBtu/hr	Total PM2.5	GOOD COMBUSTION PRACTICES	0.0075 lb/MMBtu
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	7/12/2013	Boilers	456 MMBtu/hr	Total particulate matter (TPM)	good operating practices and use of natural gas	0.0024 lb/MMBtu
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	7/12/2013	Boilers	456 MMBtu/hr	Total PM10	good operating practices and use of natural gas	0.0024 lb/MMBtu
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	7/12/2013	Boilers	456 MMBtu/hr	Total PM2.5	good operating practices and use of natural gas	0.0024 lb/MMBtu
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Auxiliary Boiler	472.4 MMBtu/hr	Total PM2.5	good combustion practices	0.0024 lb/MMBtu
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Auxiliary Boiler	472.4 MMBtu/hr	Total PM10	good combustion practices	0.0024 lb/MMBtu
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	TWO (2) AUXILIARY BOILERS	408 MMBtu/hr, EACH	Total PM10	USE OF CLEAN BURNING GASEOUS FUEL	0.0075 lb/MMBtu
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	TWO (2) AUXILIARY BOILERS	408 MMBtu/hr, EACH	Total PM2.5	USE OF CLEAN BURNING GASEOUS FUEL	0.0075 lb/MMBtu
*FL-0330	PORT DOLPHIN ENERGY LLC	FL	12/1/2011	Boilers (4 - 278 mmbtu/hr each)	278 MMBtu/hr	Total PM10	use of natural gas	0.0075 lb/MMBtu
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	AUXILIARY BOILER (AUX-1)	338 MMBtu/hr	Total PM10	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0075 lb/MMBtu
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	AUXILIARY BOILER (AUX-1)	338 MMBtu/hr	Total particulate matter (TPM)	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0075 lb/MMBtu

Appendix D, Table D-2
Utility Boilers Converted from Coal Firing to Natural Gas Firing
Conversion Completed 2014 to 2026

Facility Name	Unit	State	Conversion Date	Heat Input Rate	Pollutant	Emissions Limit	Basis of Limit	Comment
AES Petersburg	3	IN	2026	6096 MMBtu/hr	Total PM	0.23 lb/MMBtu	State SIP limit	
AES Petersburg	4	IN	2026	6096 MMBtu/hr	Total PM	0.17 lb/MMBtu	State SIP limit	
Nevada Power North Valmy Station	2	NV	2026	3048 MMBtu/hr	Total PM	0.0075 lb/MMBtu	Construction permit limit	Permit limit used for PSD applicability
Nevada Power North Valmy Station	1	NV	2025	2708 MMBtu/hr	Total PM	0.0075 lb/MMBtu	Construction permit limit	Permit limit used for PSD applicability
Alabama Power Plant Barry	4	AL	2022	3768 MMBtu/hr	Filterable PM	0.12 lb/MMBtu	State SIP limit	
Alliant Burlington	1	IA	2022	2077 MMBtu/hr	Total PM	0.8 lb/MMBtu	State SIP limit	
Big Rivers Electric Green Generating Station	1	KY	2021	2453 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	0.0075 lb/MMBtu (total PM) used for PSD applicability
Big Rivers Electric Green Generating Station	2	KY	2021	2453 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	0.0075 lb/MMBtu (total PM) used for PSD applicability
OG&E Muskogee	4	OK	2019	5789 MMBtu/hr	Total PM	0.12 lb/MMBtu	State SIP limit	0.0075 lb/MMBtu (total PM) used for PTE calculations
OG&E Muskogee	5	OK	2019	5789 MMBtu/hr	Total PM	0.12 lb/MMBtu	State SIP limit	0.0075 lb/MMBtu (total PM) used for PTE calculations
Xcel Energy Cherokee Generating Station	4	CO	2017	3520 MMBtu/hr	Filterable PM	0.030 lb/MMBtu	BART	0.0019 lb/MMBtu required to be used for emission calculations
Alliant Prairie Creek Generating Station	4	IA	2017	1370 MMBtu/hr	Total PM	0.16 lb/MMBtu	State SIP limit	
AES Harding Street Station	7	IN	2017	4346 MMBtu/hr	Total PM	none listed		0.0075 lb/MMBtu (total PM) required to be used for PTE calculations
Alabama Power Greene County Plant	1	AL	2016	2541 MMBtu/hr	Filterable PM	0.12 lb/MMBtu	State SIP limit	
Alabama Power Greene County Plant	2	AL	2016	2541 MMBtu/hr	Filterable PM	0.12 lb/MMBtu	State SIP limit	
NRG Shawville Generating Station	1	PA	2016	1345 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	
NRG Shawville Generating Station	2	PA	2016	1345 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	
NRG Shawville Generating Station	3	PA	2016	1790 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	
NRG Shawville Generating Station	4	PA	2016	1790 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	
Alabama Power Plant E.C. Gaston	1	AL	2015	2759 MMBtu/hr	Filterable PM	0.12 lb/MMBtu	State SIP limit	
Alabama Power Plant E.C. Gaston	2	AL	2015	2759 MMBtu/hr	Filterable PM	0.12 lb/MMBtu	State SIP limit	
Alabama Power Plant E.C. Gaston	3	AL	2015	2759 MMBtu/hr	Filterable PM	0.12 lb/MMBtu	State SIP limit	
Alabama Power Plant E.C. Gaston	4	AL	2015	2759 MMBtu/hr	Filterable PM	0.12 lb/MMBtu	State SIP limit	
Georgia Power Plant Yates	6	GA	2015	3559 MMBtu/hr	Filterable PM	0.24 lb/MMBtu	State SIP limit	
Georgia Power Plant Yates	7	GA	2015	3559 MMBtu/hr	Filterable PM	0.24 lb/MMBtu	State SIP limit	
AES Harding Street Station	5	IN	2015	1162 MMBtu/hr	Total PM	none listed		0.0075 lb/MMBtu (total PM) required to be used for PTE calculations

Appendix D, Table D-2
Utility Boilers Converted from Coal Firing to Natural Gas Firing
Conversion Completed 2014 to 2026

Facility Name	Unit	State	Conversion Date	Heat Input Rate	Pollutant	Emissions Limit	Basis of Limit	Comment
AES Harding Street Station	6	IN	2015	1162 MMBtu/hr	Total PM	none listed		0.0075 lb/MMBtu (total PM) required to be used for PTE calculations
Minnesota Power Laskin Energy Center	1	MN	2015	660 MMBtu/hr	Total PM	0.6 lb/MMBtu	State SIP limit	0.15 lb/MMBtu (total PM) used for PSD applicability
Minnesota Power Laskin Energy Center	2	MN	2015	660 MMBtu/hr	Total PM	0.6 lb/MMBtu	State SIP limit	0.15 lb/MMBtu (total PM) used for PSD applicability
Mississippi Power Plant Watson	4	MS	2015	2760 MMBtu/hr	Filterable PM	0.24 lb/MMBtu	State SIP limit	
Mississippi Power Plant Watson	5	MS	2015	5544 MMBtu/hr	Filterable PM	0.21 lb/MMBtu	State SIP limit	
Appalachian Power Clinch River Power Plant	1	VA	2015	2461 MMBtu/hr	PM10/PM2.5	0.0114 lb/MMBtu		
Appalachian Power Clinch River Power Plant	2	VA	2015	2461 MMBtu/hr	PM10/PM2.5	0.0114 lb/MMBtu		
We Energies Valley Power Plant	B23 (Unit 2)	WI	2015	900 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	
We Energies Valley Power Plant	B24 (Unit 2)	WI	2015	900 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	
We Energies Valley Power Plant	B21 (Unit 1)	WI	2014	900 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	
We Energies Valley Power Plant	B22 (Unit 1)	WI	2014	900 MMBtu/hr	Total PM	0.1 lb/MMBtu	State SIP limit	

Appendix E

Air Dispersion Modeling Files

KEY TO FILES

Modeling Files for the Modeling Demonstration for Alabama Power's Plant Barry Project

The following document summarizes the content of the air dispersion modeling archive (AERMAP, AERMET, AERMOD, AERSURFACE, BPIP). The contents of these folders are described below.

AERMAP – contains AERMAP files used to process terrain data to produce the receptor elevations and critical hill heights for use within the AERMOD model.

- aermap.exe : AERMAP executable (Version 24142)
- *.api : AERMAP input file
- *.rou : AERMAP file containing receptor elevations and critical hill heights for the gridded receptors and the receptors placed along the facility property
- *.tif : 10-m resolution NED files used to determine receptor elevations and critical hill heights

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AERMET – contains the meteorological data set used as input to AERMOD. ADEM provided AERMET output files via email for the concurrent five years (2019-2023) where the surface data is from Mobile, AL and the upper air data is from Slidell, LA.

- *.PFL : AERMET profile output file (input to AERMOD)
- *.SFC : AERMET surface output file (input to AERMOD)
- *.doc : Mobile Readme (from ADEM)

AERMOD – contains input, output and other key AERMOD files for the Class II SIL modeling.

- aermod_v24142.exe : AERMOD executable (Version 24142)

\SIL\[Pollutant - Avg. Period]:

- *.inp : AERMOD input file
- *.out : AERMOD output file
- *.PLT : AERMOD output plot files

AERSURFACE – contains the AERSURFACE run expanded to 3 km to review approximate percentage of urban land use.

- aersurface.exe : AERSURFACE executable (Version 24142)
- *.inp : AERSURFACE input
- *.log/ *.out/*.txt : AERSURFACE output files
- *.xlsx : landuse analysis for urban vs. rural

BPIP – contains BPIP input and output files.

- BPIPPRM.exe : BPIP executable file, with PRIME (Version 04274)
- *.bpi : BPIP input file
- *.pro : BPIP output file
- *.sup : BPIP summary file

Appendix F

GEP Documentation

Barry Unit 4 and Unit 5 Stacks

Alabama Power Company
600 North 18th Street
Post Office Box 2641
Birmingham, Alabama 35291
Telephone 205 250-1000

Alabama Power
the southern electric system

December 11, 1985

Mr. Richard E. Grusnick, Chief
Air Division
Alabama Department of
Environmental Management
1751 Federal Drive
Montgomery, AL 36130

Dear Mr. Grusnick:

Reference is made to your letter of October 22, 1985 and our meeting of November 18, 1985 concerning the Stack Height Regulations promulgated by the Environmental Protection Agency on July 8, 1985. Attached are the following documents and data:

1. Determination of Good Engineering Practice stack heights for stacks greater than 65 meters APC 200 forms for Barry, Gadsden and Gorgas Steam Electric-Generating Plants.
2. Exceptions from restrictions on credit for merged stacks with attachments.
3. Air quality modeling analysis with attachments.
4. Emission inventory for Barry Steam Plant.
5. 1983 on-site meteorological data on computer tape for all Alabama Power Company coal-fired plants.

The stacks for Units 4 and 5 at the Barry Steam Plant and the stack for Units 8-10 at the Gorgas Steam Plant are grandfathered under the regulations. The stacks for Units 4 and 5 at the Barry Steam Plant were completed in May, 1969 and June, 1970, respectively. The stack for Units 8-10 at the Gorgas Steam Plant began construction in February, 1970.

It should be noted that the Gadsden and Gorgas Steam Plants will not require any additional modeling to prove compliance with the regulations. The stacks at these plants, as indicated on the APC 200 forms, are either grandfathered or less than Good Engineering Practice stack height.

Mr. Richard E. Grusnick
Page two
December 11, 1985

The APC 200 forms and the emission inventory for the remaining affected plants will be submitted within two weeks. This information has been delayed due to a recheck of construction drawings by our surveyors.

I would appreciate a meeting to discuss this information as soon as possible. If you have any questions, please call me.

Sincerely,

Willard L. Bowers

W. L. Bowers, Manager
Environmental Compliance

WDH:dy

Attachment

DETERMINATION OF GOOD ENGINEERING PRACTICE STACK HEIGHT
FOR STACKS GREATER THAN 65 METERS

1. Company ALABAMA POWER COMPANY

2. Address P. O. Box 2641, Birmingham, AL 35291

3. Permit Unit/Source Description Barry Steam Plant Unit 4

   (a) Actual stack height above grade 600 feet

   (b) List the air emission sources which utilize this stack. Describe the air pollution control system. Attach diagrams or further explanation as needed. Barry Steam Plant Boiler 4 with electrostatic precipitators.

4. Attach a top-view schematic drawing of the plant (drawn-to-scale) including geographical orientation. Label all buildings and stacks. Include height, width, and length of all buildings.

5. (a) GEP stack height Grandfathered

   (b) Date construction started on stack

   (c) In the space provided below or in attachments show the GEP calculations and indicate the building used.

   See attached information on grandfathering.

6. Highest terrain elevation within 1/2 mile:

   (a) Height 40 feet

   (b) Distance and direction from stack 0.5 miles west (taken from U. S. Geological Map Citronelle 1:62500 Quad)

W. L. Bowers
Name of Company Official

William L. Bowers
Signature

12/12/85
Date

ADC 200

DETERMINATION OF GOOD ENGINEERING PRACTICE STACK HEIGHT FOR STACKS GREATER THAN 65 METERS

1. Company ALABAMA POWER COMPANY

2. Address P. O. Box 2641, Birmingham, AL 35291

3. Permit Unit/Source Description Barry Steam Plant Unit 5

   (a) Actual stack height above grade 600 feet

   (b) List the air emission sources which utilize this stack. Describe the air pollution control system. Attach diagrams or further explanation as needed. Barry Steam Plant Boiler 5 with electrostatic precipitators.

4. Attach a top-view schematic drawing of the plant (drawn-to-scale) including geographical orientation. Label all buildings and stacks. Include height, width, and length of all buildings.

5. (a) GEP stack height grandfathered

   (b) Date construction started on stack ______

   (c) In the space provided below or in attachments show the GEP calculations and indicate the building used.

   See attached information on grandfathering.

6. Highest terrain elevation within ½ mile:

   (a) Height 40 feet

   (b) Distance and direction from stack 0.5 Miles West (Taken from U. S. Geological Map Citronelle 1:62500 Quad)

W. L. Bowers
Name of Company Official

William L. Bowers
Signature

12/12/85
Date

Appendix G

FLM AQRV Waiver

Pitts, Brittany R.

From:	Allen, Tim <tim_allen@fws.gov>
Sent:	Wednesday, October 1, 2025 10:23 AM
To:	Pitts, Brittany R.; FWHQ AQ NEPA; Ming, Jaron E
Cc:	Healan, Geoffrey; Owen, Jim; Southwick, Scott; Natoshia Martin
Subject:	Re: [EXTERNAL] Request for Determination - Class I Area Impact

Hi Brittany,

Thank you for working with me on updating the project submission. After reviewing the summary information provided for Alabama Power Company, the US FWS will not request additional Class I AQRV analysis. If the project were to significantly change (Q/d > 10), please resubmit for additional review.

Thank you,
Tim Allen

From: Pitts, Brittany R. <BRPITTS@southernco.com>
Sent: Wednesday, October 1, 2025 8:09 AM
To: FWHQ AQ NEPA <AQ_NEPA@fws.gov>; Allen, Tim <tim_allen@fws.gov>; catherine_collins@fws.gov <catherine_collins@fws.gov>; Ming, Jaron E <jaron_ming@fws.gov>
Cc: Healan, Geoffrey <gah@adem.alabama.gov>; Owen, Jim <jo@adem.alabama.gov>; Southwick, Scott <ssouthwick@adem.alabama.gov>; Natoshia Martin <natoshia.martin@adem.alabama.gov>
Subject: [EXTERNAL] Request for Determination - Class I Area Impact

Please see revised language below and in attachment.

Alabama Power Company (APC) proposes to convert the existing Unit 5 coal-fired boiler at Barry Steam Electric Generating Plant (Plant Barry) to natural gas. Plant Barry is located approximately 20 miles north of Mobile, Alabama. APC is developing an air permit application for submittal to the Alabama Department of Environmental Management (ADEM) for the issuance of an Air Permit authorizing construction of this project. Current emission calculations indicate the Project will be a major modification and trigger PSD review for PM_{10} and $PM_{2.5}$. Federal and ADEM regulations require notice of these type of permit applications to the appropriate Federal Land Manager of nearby Class I Areas.

The proposed project is located approximately 132 km from the Breton National Wildlife Refuge Class I Area. There are no other Class I Areas within 300 km of Plant Barry.

The FLAG 2010 guidance states that proposed sources with a Q/d ratio less than 10 will likely not have an adverse impact on a Class I Area. As I'm sure you are aware, the Q in the Q/d is the sum of annual emissions (in tons per year, based on 24-hour maximum allowable emissions) of SO_2, NO_X, H_2SO_4, and PM_{10} emissions from the project.

As shown in the attached form the project will result in decrease in SO_2, NO_X and H_2SO_4 therefore the only pollutant potentially impacting AQRV's would be PM10. The Q for this calculation only reflects Unit 5's full future short-term potential PM_{10} emission rate expressed in tons/year. This is conservative since this does not account for decreases associated with past actual emissions from the Unit firing coal. The total sum of the relevant emissions is 249 tons per year for this project. The d in the Q/d is the distance (km) from the source to the Class I Area of interest; in this case Breton National Wildlife Refuge. Regarding this project relative to Breton, Q=249 and d=132, and the resultant Q/d ratio = 1.9. This is far less than 10, the screening level suggested in the FLM guidance. Given this low Q/d ratio, APC believes an AQRV modeling analysis for regional haze and deposition of Breton National Wildlife Refuge Class I Area is not warranted.

Please find attached a completed Southern Region US Forest Service "Request for Determination of Need for a Class I AQRV Modeling Analysis" form that provides all the relevant information for the US Fish and Wildlife Service to make their determination regarding this project. It would be greatly appreciated if you could provide a response within the next two weeks as ADEM requires your determination to be included in the air permit application.

Thank you for considering our request and we look forward to your response. If you have any questions, please contact me.

Thanks,

Brittany Pitts
Alabama Power Company
Environmental Affairs
Cell: 334-202-8992

Alabama Power

Request for Determination of Need for a Class I AQRV Modeling Analysis
Southern Region, U.S. Forest Service

Facility Name (Company Name)	Barry Steam Electric Generating Plant (Alabama Power Company)
New Facility or Modification?	Modified Unit at Existing Facility
Source Type/BART Applicability	N/A
Project Location (County/State/ Lat. & Long. in decimal degrees)	Mobile County, Alabama. 31.00N, 88.01W

Application Contacts

Applicant		*Consultant*		*ADEM Contacts*	
Company	Alabama Power Company	**Company**	AECOM	**Agency**	ADEM
Contact	Brittany Pitts	**Contact**	Jeffrey Connors	**Contacts**	Scott Southwick Geoffrey Healan Jim Owen
Address	600 18th St N, Birmingham, AL 35203	**Address**	250 Apollo Drive Chelmsford, MA 01824	**Address**	1400 Coliseum Blvd. Montgomery, AL 36110
Phone #	334.202.8992	**Phone #**	978.905.2166	**Phone #**	(334) 279-3079 334.270.5683 (334)-271-7911
Email	brpitts@southernco.com	**Email**	jeffrey.connors@aecom.com	**Email**	ssouthwick@adem.alabama.gov GAH@adem.alabama.gov jo@adem.alabama.gov

Briefly Describe the Proposed Project

Alabama Power Company (Alabama Power) is proposing to convert an existing coal-fired boiler to natural gas at an existing generation facility in Alabama (Unit 5 at Barry Steam Electric Generating Plant [Plant Barry]). Plant Barry is an existing major source of criteria air pollutants, and the proposed Project is expected to be considered a "major modification" under Prevention of Significant Deterioration (PSD) permitting requirements. As such, Alabama Power expects to apply to the Alabama Department of Environmental Management ("ADEM") for an Air Permit Authorizing Construction of the Project under ADEM Admin. Code r.335-3-14-.04. Based on preliminary information, Alabama Power expects the Project to be subject to PSD Review for particulate matter (PM) less than 10 microns in diameter (PM_{10}) and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). The permit application would demonstrate that the proposed Project can be expected to comply with all applicable state and federal air quality regulations.

Proposed Emissions and BACT

Criteria Pollutant	***Emissions[1]***		***Emission Factor (AP-42, Stack Test, Other?)***	***Proposed BACT for Modified NG Boiler***
	Modified NG Boiler Maximum Hourly (lb/hr)	***Modified NG Boiler Total Annual (tons/yr)***		
Nitrogen Oxides	379.3	-70.8 (or 0)	Vendor data/estimate	n/a
Sulfur Dioxide	4.6	-407.8 (or 0)	Part 75 PNG rate	n/a
Particulate Matter (PM_{10}/$PM_{2.5}$)	56.9	75	AP-42	Natural gas firing
Sulfuric Acid Mist	0.035	-211.9 (or 0)	EPRI Paper	n/a

Proximity to U.S. Forest Service Class I Areas

Class I Area	Breton National Wildlife Refuge		*Calculated Q/d (from above)*
Distance from Facility (km)	~132		1.9

[1]Data is preliminary and subject to change. The annual emissions shown here are reflective of future projected emissions less past actual emissions, consistent with the PSD applicability determination. For the Q/d calcuation, 249.2 tons was used for Q (see email).

Appendix H

AQS Data Report ($PM_{2.5}$)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

User ID: DROEBLING

DESIGN VALUE REPORT

Report Request ID: 2339813 Report Code: AMP480 Dec. 16, 2025

GEOGRAPHIC SELECTIONS

Tribal Code	State	County	Site	Parameter	POC	City	AQCR	UAR	CBSA	CSA	EPA Region
	01	097	0003								

PROTOCOL SELECTIONS

Parameter Classification	Parameter	Method	Duration
DESIGN VALUE	88101		

SELECTED OPTIONS

Option Type	Option Value
SINGLE EVENT PROCESSING	EXCLUDE REGIONALLY CONCURRED EVENTS
MERGE PDF FILES	YES
AGENCY ROLE	PQAO
USER SITE METADATA	STREET ADDRESS
QUARTERLY DATA IN WORKFILE	NO
WORKFILE DELIMITER	,
USE LINKED SITES	YES

DATE CRITERIA

Start Date	End Date
2024	2024

APPLICABLE STANDARDS

Standard Description
PM25 24-hour 2024
PM25 Annual 2024

Notes: 1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').

Pollutant: Site-LevelPM2.5 - Local Conditions(88101)
Standard Units: Micrograms/cubic meter (LC)(105)
NAAQS Standard: PM25 24-hour 2024 / PM25 Annual 2024
Statistic: Annual Weighted Mean **Level:** 9
Statistic: Annual 98th Percentile **Level:** 35

Design Value Year: 2024
REPORT EXCLUDES MEASUREMENTS WITH REGIONALLY CONCURRED EVENT FLAGS.

State Name: Alabama

Site_ID / STREET ADDRESS	2024 Cred. Days	2024 Comp. Qrtrs	2024 98th Perctil	2024 Wtd. Mean	2024 Cert& Eval	2023 Cred. Days	2023 Comp. Qrtrs	2023 98th Perctil	2023 Wtd. Mean	2023 Cert& Eval	2022 Cred. Days	2022 Comp. Qrtrs	2022 98th Perctil	2022 Wtd. Mean	2022 Cert& Eval	24-Hour Design Value	24-Hour Valid Ind.	Annual Design Value	Annual Valid Ind.
01-097-0003 Iroquois and Azalea, CHICKASAW, MOBILE CO., ALABAMA	342	4	17.1	8.0	Y	342	4	19.2	8.7	Y	109	3	14.8	7.9*	Y	17	Y	8.2	Y

Notes: 1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').

CERTIFICATION EVALUATION AND CONCURRENCE FLAG MEANINGS

FLAG	MEANING
M	The monitoring organization has revised data from this monitor since the most recent certification letter received from the state.
N	The certifying agency has submitted the certification letter and required summary reports, but the certifying agency and/or EPA has determined that issues regarding the quality of the ambient concentration data cannot be resolved due to data completeness, the lack of performed quality assurance checks or the results of uncertainty statistics shown in the AMP255 report or the certification and quality assurance report.
S	The certifying agency has submitted the certification letter and required summary reports. A value of "S" conveys no Regional assessment regarding data quality per se. This flag will remain until the Region provides an "N" or "Y" concurrence flag.
U	Uncertified. The certifying agency did not submit a required certification letter and summary reports for this monitor even though the due date has passed, or the state's certification letter specifically did not apply the certification to this monitor.
X	Certification is not required by 40 CFR 58.15 and no conditions apply to be the basis for assigning another flag value
Y	The certifying agency has submitted a certification letter, and EPA has no unresolved reservations about data quality (after reviewing the letter, the attached summary reports, the amount of quality assurance data submitted to AQS, the quality statistics, and the highest reported concentrations).

Notes: 1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').