PRELIMINARY DETERMINATION

Alabama Power Company – Barry Steam Electric Generating Plant
Facility No. 503-1001
Unit 5 – Natural Gas Conversion
Air Permit No. X021

INTRODUCTION

On November 14, 2025, the Department received an application from Alabama Power Company – Barry Steam Electric Generating Plant (APC) proposing to convert the existing Unit 5 Power Boiler from a coal-fired steam electric generating unit to a natural gas fired steam electric generating unit.

FACILITY DESCRIPTION

APC is an existing electric power generation facility. The facility currently operates 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 generating units (Units 6A/6B and 7A/7B), and one 1-on-1 combined cycle electric generating unit (Unit 8). APC also operates other smaller sources of air emissions such as an auxiliary boiler, cooling towers, and various small engines. APC is currently a major source of regulated air pollutants with respect to Title V and a major source for hazardous air pollutants (HAPs). The facility is currently operating under a permit shield for Major Source Operating Permit (MSOP) No. 503-1001, issued on February 2, 2021, modified on April 4, 2023,and the following air permits:

TABLE 1: LIST OF CURRENT AIR PERMITS

PERMIT NUMBER	PERMIT DESCRIPTION	ISSUANCE DATE
503-1001-X014	Unit 8 Combined Cycle Combustion Turbine and Heat Recovery Steam Generator with Duct Burner, Oxidation Catalyst, and Selective Catalytic Reduction (SCR) (combined heat input of 4,883 MMBtu/hr) Unit 9 Combined Cycle Combustion Turbine and Heat Recovery Steam Generator with Duct Burner, Oxidation Catalyst, and Selective Catalytic Reduction (SCR) (combined heat input of 4,883 MMBtu/hr)	June 13, 2024 (reissued)
503-1001-X015	90.5 MMBtu/hr Auxiliary Boiler Cooling Towers	November 9, 2020
503-1001-X016	Two 1,500 kW Diesel Emergency Generator Engines 236 kW Diesel Emergency Fire Pump Engine	November 9, 2020
503-1001-X017	Blackstart Emergency Generator Engines	April 7, 2021
503-1001-X020	Natural Gas-Fired Unit 4 with SNCR and Oxidation Catalyst	August 5, 2022

PROJECT DESCRIPTION

APC has proposed to modify the existing Unit 5 Power Boiler from a coal-fired steam electric generating unit to a natural gas fired steam electric generating unit. The conversion would consist of replacing the existing coal burners with new natural gas burners and associated equipment. The new burners will be installed at five boiler elevations with eight burners per elevation. Additional piping will also be needed to support the conversion. The facility has also proposed to maintain the existing selective catalytic reduction (SCR) and install an oxidation catalyst as part of the project. Following the conversion, 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.

PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

APC is currently considered a major stationary source with respect to prevention of significant deterioration (PSD). In order for a major stationary source to be required to undergo a PSD review, it would have to undergo a major modification. The definition of a major modification is found in ADEM Admin. Code r. 335-3-14-.04(2)(b) and it reads as follows: any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any regulated NSR pollutant. To determine if the proposed project would result in a significant net emission increase, one or a combination of the procedures to calculate emissions listed in ADEM Admin. Code r. 335-3-14-.04(1)(f) through (i) would need to be used. The proposed project involves an existing unit; therefore, the facility has chosen to use the actual-to-projected-actual applicability test, as listed in ADEM Admin. Code r. 335-3-14-.04(1)(f), to determine the emissions increase.

For the actual-to-projected-actual applicability test, a significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (PAE) and the baseline actual emissions (BAE), for the existing emission unit, equals or exceeds the significant rate for that pollutant. Using the procedures listed in the applicability test, APC determined the BAE in accordance with ADEM Admin. Code r. 335-3-14-.04(2)(uu)1. and determined the future PAE in accordance with ADEM Admin. Code r. 335-3-14-.04(2)(nn).

The BAE for an existing electric utility steam generating unit is the average rate at which the unit actually emitted the pollutant during any consecutive 24-month period within the 5-year period immediately preceding actual construction of the project. APC intends to begin actual construction of the proposed project in October 2026 and has selected the consecutive 24-month period of November 2021 through October 2023 as the BAE for all pollutants. To determine the BAE for the proposed project, the facility used data from continuous emissions monitoring systems (CEMS), performance testing, and various emission factors with total heat inputs recorded from CEMS.

The future PAE means the maximum annual rate, in tons per year, at which an existing emission unit is projected to emit in any one of the 5-years (consecutive 12-month period) following the date the unit resumes regular operation after the project, or any one of the 10-years following that date, if the project involves increase the emissions unit's design capacity or its potential to emit that regulated pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase. APC calculated the future PAE using emission factors obtained through various means, including: 40 CFR Part 75, engineering estimates from the vendors for the SCR and oxidation catalyst, AP-42, greenhouse gas reporting rule, and Electric Power Research Institute (EPRI). The facility used a maximum projected 12-month heat input of 43,188,990 MMBtu/yr.

The following table shows the net emission increases as a result of this proposed project and the PSD significant emissions threshold values:

TABLE 2. NET CHANGE IN EMISSIONS FROM PROPOSED UNIT 5 CONVERSION PROJECT

POLLUTANT	BASELINE ACTUAL EMISSIONS (TPY)	PROJECTED ACTUAL EMISSIONS (TPY)	NET EMISSIONS (TPY)	PSD SIGNIFICANCE THRESHOLD (TPY)	PSD SIGNIFICANT EMISSIONS INCREASE
Sulfur Dioxide (SO_2)	420.7	13.0	-407.8	40	No
Nitrogen Oxides (NO_X)	1,150.5	1,079.7	-70.8	40	No
Particulate Matter (PM)[1]	131.0	41.0	-89.9	25	No
Particulate Matter < 10µ (PM_{10})[2]	87.0	162.0	75.0	15	Yes
Particulate Matter < 2.5µ ($PM_{2.5}$)[2]	44.1	162.0	117.9	10	Yes
Carbon Monoxide (CO)	465.23	399.5	-65.7	100	No
Ozone[3]	54.3	86.8	32.5	40	No
Greenhouse Gases (GHG) CO_{2e}	3,190,182.0	2,528,657	-661,525	75,000	No
Sulfuric Acid Mist (H_2SO_4)	212.0	0.099	-211.9	7	No
Lead (Pb)	0.017	0.011	-0.006	0.6	No
Fluorides	0.23	0	-0.23	3	No

[1]Only represents filterable portion of particulate matter.

[2]Represents filterable and condensable portion of particulate matter.

[3]Emission estimates are calculated as volatile organic compounds (VOC), a precursor for ozone.

The proposed project would qualify as a major source modification since the emissions of particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) would result in a net increase more than the significant emissions rates listed in ADEM Admin. Code r. 335-3-14-.04(2)(w). The proposed project would be subject to ADEM Admin. Code r. 335-3-14-.04 which was adopted pursuant to the federal requirements for PSD.

A major source or major modification under a PSD review must be constructed with Best Available Control Technology (BACT). Additionally, the effects on soils, vegetation, visibility, and ambient air quality must be addressed for each applicable pollutant. If the net air emissions increase of any applicable pollutant is less than the pollutant's significance threshold, a PSD review is not necessary for that pollutant.

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The Clean Air Act (CAA) prescribes several technology-based limitations affecting new or modified air pollution sources. Among these limitations is BACT. Any new or modified units located at a major source for PSD with significant net emission increases must be constructed with BACT. Individual BACT determinations are performed for each pollutant subject to a PSD review emitted from the same emission unit. Each BACT analysis is determined on a case-by-case basis, evaluating the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of reduced

emissions that the technology would bring. APC has elected to follow a top-down approach to determine BACT for this proposed modification. The five steps of a top-down approach are listed below:

Step 1: Identification of all control technologies.
Step 2: Elimination of technically infeasible options.
Step 3: Ranking of remaining control technologies by control effectiveness.
Step 4: Evaluation of the most effective controls and documentation of results.
Step 5: Selection of BACT.

The following is a discussion of the top-down BACT analysis for the conversion of Unit 5 from coal-fired to natural gas-fired. The proposed project would result in a significant net increase for PM_{10} and $PM_{2.5}$. The control options for these pollutants are undifferentiated; therefore, APC has chosen to evaluate these pollutants together as particulate matter.

Particulate Matter (PM)

Particulate matter (PM) from combustion sources can include a combination of filterable and condensable particles. The filterable particles are related to impurities in the fuel, incomplete combustion products, and to airborne dust or particles suspended in the combustion air intake. The condensable particles are attributable primarily to sulfate aerosols and high molecular weight VOCs. Additionally, converted units can have physical or design features and existing conditions that could also affect the variability of PM emission rates. A converted unit could exhibit increased filterable PM from the presence of residual dust associated with coal operations or increased condensable PM from decreased combustion efficiency associated with combustion zone geometry and combustion air flow system capacity.

Step 1: Identify All Control Technologies

APC reviewed BACT determinations found in the RACT/BACT/LAER Clearinghouse (RBLC) listings, additional literature for utility units converted from coal firing to natural gas firing, and relevant existing and proposed federal and state emissions standards to identify control technologies. The facility considered the following control techniques/technologies to reduce PM emissions.

- Option 1: Fabric Filter (Baghouse)
- Option 2: Electrostatic Precipitator
- Option 3: Use of Gaseous Fuel (Natural Gas)
- Option 4: Good Combustion Practices

Option 1: Fabric Filter (Baghouse)

A fabric filter is an air pollution control device designed to capture filterable PM through physical filtration. The system contains a series of long tubular fabric bags 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 passes through. The PM particles accumulate inside the bags and is periodically removed and collected for disposal. This control device is more effective at controlling the filterable portion of PM instead of the condensable portion.

Option 2: Electrostatic Precipitator (ESP)

An electrostatic precipitator (ESP) applies a negative charge to the PM particles in a gas steam as it passes through high-voltage discharge electrodes and grounded collection plates. The electrostatic field between the electrodes and collection plates moves the charged particles toward the collection plates where they adhere. The PM particles accumulate on the surface of the

collection plates and are periodically removed and collected for disposal. This control device is generally more effective at controlling the filterable portion of PM, but specialized ESP designs (*i.e. wet ESP*) can be used to collect the condensable portion of PM for certain applications.

Option 3: Use of Gaseous Fuel (Natural Gas)

Natural gas is primarily methane and other low molecular weight hydrocarbons and contains virtually no mineral matter or non-combustible ash. Natural gas also has a relatively low sulfur content compared to other fuel sources. Therefore, when natural gas is combusted very low levels of filterable PM and condensable PM are produced.

Option 4: Good Combustion Practices

Good combustion practices consist of ensuring the physical conditions and operational mechanisms are ideal for complete combustion and minimal PM formation. These practices focus on ensuring that the three principal elements of the fuel combustion process are maximized by maintaining a high, uniform temperature within the combustion zone, providing sufficient residence time, and providing adequate fuel-air mixing.

Step 2: Eliminate Technically Infeasible Options

APC evaluated each of the potential control technologies/techniques for technical feasibility.

Option 1: Fabric Filter (Baghouse)

A fabric filter is not a technically feasible control option for PM emissions from the proposed conversion, because it is designed for significantly different exhaust gas loadings and not for controlling the low concentrations of PM present in gaseous fuel fire applications.

Option 2: Electrostatic Precipitator

An ESP is not a technically feasible control option for PM emissions from the proposed conversion, because it is designed for significantly different exhaust gas loadings and not for controlling the low concentrations of PM present in gaseous fuel fire applications.

Option 3: Use of Gaseous Fuel (Natural Gas)

The use of clean gaseous fuel, natural gas, would be technically feasible.

Option 4: Good Combustion Practices

The use of good combustion practices would be technically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The use of natural gas and good combustion practices are the only available and technically feasible control options for PM emissions for the conversion project for Unit 5. The facility has proposed these options as BACT. Therefore, no ranking of control options is required.

Step 4: Evaluating the Most Effective Controls and Document Results

The use of natural gas and good combustion practices are the top control options for PM emissions for the conversion project for Unit 5. The facility has proposed these options as BACT. Therefore, no further evaluation of the impacts of the PM control options is required.

Step 5: Select BACT

The use of natural gas and good combustion practices would be considered the most effective PM control for the boiler. APC has proposed using natural gas and good combustion practices as BACT for the boiler and proposed a limit of 0.0075 lb/MMBtu (HHV) and 56.9 lb/hr, based on the average of three test runs. It is noted that the PM_{10} and $PM_{2.5}$ limit includes filterable and condensable particles. A review of the RBLC revealed that the proposed control design would provide PM control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for PM emissions from Unit 5. The table below summarizes the PM BACT limits for the proposed conversion project.

TABLE 3. BACT SUMMARY FOR PROPOSED UNIT 5 CONVERSION PROJECT

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT	AVERAGING TIME	COMPLIANCE DETERMINATION METHOD
Filterable and Condensable Particulate Matter (PM_{10} and $PM_{2.5}$)	Use of natural gas and good combustion practices	0.0075 lb/MMBtu (HHV) and 56.9 lb/hr	N/A	3-run stack test using EPA Reference Methods 5 and 201A or 202, as applicable.

AIR QUALITY ANALYSIS (MODELING)

An applicant for a PSD permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new sources or modification. The main purpose of the air quality analysis is to demonstrate that new emissions from a proposed major stationary source or major modification will not cause or contribute to a violation of any applicable National Ambient Air Quality Standards (NAAQS) or PSD increment. Ambient impacts of non-criteria pollutants must also be evaluated. Generally, the analysis will include (1) an assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results, and (2) predictions, using dispersion modeling, of ambient concentrations that will result from the applicant's proposed project and future growth associated with the project.

Significant Impact Level (SIL)

The proposed conversion project will cause a net emission increase of PM_{10} and $PM_{2.5}$. A Significant Impact Level (SIL) Modeling Analysis was conducted to determine if the PM_{10} and $PM_{2.5}$ concentrations would significantly impact the ambient air quality. In this analysis, only the project emissions are modeled, and the maximum modeled concentration is compared to the pollutant-specific U.S. EPA-established SIL. The SIL for Class I and Class II Areas for particulate matter (PM_{10} and $PM_{2.5}$) are listed in the table below.

TABLE 4. SIGNIFICANT IMPACT LEVELS (SIL) FOR CLASS I AND CLASS II AREAS

POLLUTANT		AVERAGING TIME	CLASS I (µg/m^3)	CLASS II (µg/m^3)
Particle Pollution (PM)	**PM_{10}**	Annual	-	1
		24-hour	-	5
	$PM_{2.5}$	Annual	0.06	0.13
		24-hour	0.07	1.2

A complete review of the air quality analysis can be found in Attachment 1. As can be seen from the review, the predicted pollutant concentrations are less than the established SILs.

National Ambient Air Quality Standards (NAAQS)

There are established NAAQS for carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM_{10} and $PM_{2.5}$), and sulfur dioxide (SO_2). The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The following table presents the applicable standards for the pollutants under PSD review.

TABLE 5. NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS) FOR PARTICULATE MATTER

POLLUTANT		AVERAGING TIME	PRIMARY STANDARD	SECONDARY STANDARD
Particle Pollution (PM)	**$PM_{2.5}$**	Annual	9.0 µg/m^3	15.0 µg/m^3
		24-hour	35 µg/m^3	35 µg/m^3
	PM_{10}	24-hour	150 µg/m^3	150 µg/m^3

A complete review of the air quality analysis can be found in Attachment 1. As can be seen from the review, the predicted pollutant concentrations are less than the NAAQS, and the NAAQS are not expected to be exceeded.

PSD Increment

The PSD Increment is the maximum allowable increase in concentration that can occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging time) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. The air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed. U.S. EPA has established PSD Increments for, particulate matter (PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), and nitrogen dioxide (NO_2). The PSD Increments are further broken based on area classifications.

The PSD requirements provide for a system of area classifications which affords an opportunity to identify local land use goals. There are three area classifications. Each classification differs in terms of the amount of growth it would permit before significant air quality deterioration would be deemed to occur. The following is a brief synopsis of each class area and how it relates to this project. Class I areas have the smallest increments and thus allow only a small degree of air quality deterioration. Class II areas can accommodate normal well-managed industrial growth. Class III areas have the largest increments and thereby provide for larger amount of development than either Class I or Class II areas. Presently, there are no Class III areas in Alabama.

The table below shows the Class I and II PSD increments for the pollutants under PSD review.

TABLE 6. PSD INCREMENTS FOR CLASS I AND CLASS II AREAS

POLLUTANT		AVERAGING TIME	CLASS I (µg/m^3)	CLASS II (µg/m^3)
Particle Pollution (PM)	PM_{10}	Annual	4	17
		24-hour	8	30
	$PM_{2.5}$	Annual	1	4
		24-hour	2	9

The following is a brief synopsis of each class area and how it relates to this project:

Class I Areas

Class I Areas have the smallest increments and thus allow only a small degree of air quality deterioration. Air Permit application forms submitted by APC document that the closest Class I Area, the Breton Wildlife Refuge, is approximately 132 km from the facility. Therefore, a Class I increment analysis was not required by the Department. However, APC submitted a Request for Applicability of Class I Area Modeling Analysis Form to the Federal Land Manager (FLM) for review of the proposed project. The FLM determined that no additional analysis is necessary at this time.

Class II Areas

Class II areas can accommodate normal well-managed industrial growth. APC is located in a Class II Area. Attachment No. 1 provides a review of the PSD Class II increment analysis. As can be seen from the review, there are no predicted violations of the Class II increment for any averaging period.

Class III Areas

Class III areas have the largest increments and thereby provide for larger amount of development than either Class I or Class II areas. Presently, there are no Class III areas in the state of Alabama. Therefore, no Class III area analysis was performed for this project.

Additional Impact Analysis

All PSD permit applicants must prepare an additional impact analysis, for each pollutant subject to regulation, which would be emitted by the proposed new source or modification. This analysis assesses the impacts of air, ground, and water pollution on soils, vegetation, and visibility caused by an increase in emissions and from associated growth. The additional impact analysis generally has three parts: growth, soils and vegetation, and visibility impairment.

Growth

The purpose of a growth analysis is to predict how much new growth is likely to occur as a result of the project and the resulting air quality impacts from this growth. The growth analysis evaluates the impact associated with the project on the general commercial, residential, and industrial growth within the project vicinity. The facility is an existing source, and the proposed project would not be expected to contribute to significant growth at the facility. Industrial, commercial, and residential growth is not anticipated to occur at an increased rate in the future as a result of the project.

Soils and Vegetation

As the impacts from the proposed project will be less than the primary NAAQS, which are intended to protect human health and are more stringent than standards intended to protect soil or vegetation, the project is not expected to have a significant impact on the surrounding soil. The modeled impacts of PM_{10} and $PM_{2.5}$ are less than the Class II significant impact level (SIL). In summary, the project is not expected to result in significant impact on soil, vegetation, or wildlife in the area surrounding the facility.

Visibility Impairment

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. For distances greater than 50 km, visibility impairment is considered to take the form of regional haze rather than a distinct plume. APC performed a Q/d screening analysis to determine if a full Class I Air Quality Related Values (AQRV) evaluation would be required for the proposed project. The Q/d screening analysis calculates a ratio of the potential project emissions of visibility-impairing pollutants (SO_2, NO_2, PM_{10}, sulfuric acid mist) in tons per year to the distance in kilometers to the Class I area. Since the ratio was less than 10, no further analyses were required.

STATE REGULATIONS

CHAPTER 335-3-1, GENERAL PROVISIONS

ADEM Admin. Code r. 335-3-1-.04, "Monitoring, Records, and Reporting"

ADEM Admin. Code r. 335-3-1-.04(1) states the Director may require the owner or operator of any air contaminant source to establish and maintain such records; make such reports; install, use, and maintain such monitoring equipment or methods; sample such emissions in accordance with such methods at such locations, intervals, and procedures as the Director may prescribe; and provide such periodic emission reports as required.

The Department cites this rule (along with the similar r. 335-3-16-.05(c) in the context of major source operating permits) as the authority to stipulate monitoring, recordkeeping, and reporting requirements as needed to determine continuous compliance with operating and emission standards such as the BACT limits determined above.

CHAPTER 335-3-4, CONTROL OF PARTICULATE EMISSIONS

ADEM Admin. Code r. 335-3-4-.01, "Visible Emissions"

ADEM Admin. Code r. 335-3-4-.01(1)(a) states that no person shall emit particulate emissions to the atmosphere of an opacity greater than twenty percent (20%) over a six-minute period, except for one six-minute period in any sixty-minute period. ADEM Admin. Code r. 335-3-4-.01(1)(b) states that during one six-minute period in any sixty-minute period a person may discharge into the atmosphere from any source of emissions, particulate of an opacity not greater than that designated as forty percent (40%) opacity.

The state opacity standard applies at all times. Following the conversion, the unit would combust natural gas only, opacity is expected to be negligible during operation of the unit.

ADEM Admin. Code r. 335-3-4-.02, "Fugitive Dust and Fugitive Emissions"

All major facilities are now required to submit a Facility-Wide Fugitive Dust Plan, if necessary. There are no raw materials, storage piles, products, etc. capable of generating fugitive dust associated with this

proposed project. In other words, emissions are expected to be insignificant, as is the likelihood that the facility will violate the general SIP requirements related to fugitive dust. Therefore, additional specific requirements for fugitive dust, including additional monitoring, recordkeeping, or reporting requirements, are not necessary for this proposed project in order to ensure compliance with the SIP.

ADEM Admin. Code r. 335-3-4-.03, "Fuel Burning Equipment"

APC is located in Mobile County, which is currently classified as a Class 1 County, as stated in Appendix A of ADEM Admin. Code r. 335-3. ADEM Admin. Code r. 335-3-4-.03(1) states that no person shall cause or permit the emission of particulate matter from fuel-burning equipment in a Class 1 County in excess of the amount shown in Table 4-1 for the heat input allocated to such source. Therefore, the unit would be subject to Class 1 Country allowable PM emission limit of 0.12 lb/MMBtu, as listed in Table 4-1. Following the conversion, the unit would meet this limit by combusting natural gas only.

CHAPTER 335-3-5, CONTROL OF SULFUR COMPOUND EMISSIONS

ADEM Admin. Code r. 335-3-5-.01, "Fuel Combustion"

APC is located in Mobile County, which is currently classified as a Category I County, as stated in Appendix B of ADEM Admin. Code r. 335-3. Therefore, the unit would be subject to the Category I County SO_2 emission limit of 1.8 lb/MMBtu. Following the conversion, the unit would meet this limit by combusting natural gas only.

ADEM Admin. Code r. 335-3-5-.06 through 335-3-5-.36, "Cross-State Air Pollution Rule (CSAPR)"

Unit 5 is currently subject to the Cross-State Air Pollution Rule (CSAPR) and the applicable provisions in ADEM Admin. Code r. 335-3-5-.06 through 335-3-5-.36 for sulfur dioxide (SO_2). APC will continue to comply with these requirements.

CHAPTER 335-3-8, CONTROL OF NITROGEN OXIDE EMISSIONS

ADEM Admin. Code r. 335-3-8-.07 through 335-3-8-.70, Cross-State Air Pollution Rule (CSAPR)

Unit 5 is currently subject to the Cross-State Air Pollution Rule (CSAPR) and subject to the applicable provisions in ADEM Admin. Code r. 335-3-8-.07 through 335-3-5-.70 for nitrogen oxides (NO_x). APC will continue to comply with these requirements.

APC has stated that the boiler will maintain the existing selective catalyst reduction (SCR) system to minimize nitrogen oxide (NO_x) emissions. The SCR system consists of a single reactor installed in a vertical flow configuration. APC has stated that the reactor is designed to accommodate up to four catalyst layers, allowing for operational flexibility and optimization of NO_x reduction efficiency. Ammonia is injected upstream of the reactor and automatically controlled to maintain the desired NO_x emission rate. APC has stated that the SCR has a design removal efficiency of 67%. The SCR system shall be operated, as necessary, and considering technology limitations, in order to comply with CSAPR.

CHAPTER 335-3-14, AIR PERMITS

ADEM Admin. Code r. 335-3-14-.04, "Air Permits Authorizing Construction in Clean Air Areas [Prevention of Significant Deterioration Permit (PSD)]"

ADEM Admin. Code r. 335-3-14-.04(17)(e)3. states the owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in subparagraph (17)(e)1.(ii) of this Rule; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following the

resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of the regulated NSR pollutant at such emissions unit. Since there is a reasonable possibility that the proposed project could result in a significant emissions increase of VOC, the facility will be required to calculate, record, and submit a report of annual VOC emissions for 10 years following the completion of the proposed project.

APC has stated that the boiler will be equipped with an oxidation catalyst system to control CO and VOC emissions. APC has stated that the oxidation catalyst has a design removal efficiency of 33% for VOC. To demonstrate initial compliance with the VOC emission rate, the facility will be required to perform an initial performance test using EPA Reference Method 25, 25A, or 25B of 40 CFR Part 60, Appendix A-7. To demonstrate continuous compliance, the oxidation catalyst shall be inspected for structural integrity, build up on the catalyst, and clogging of the catalyst medium at least every 8,760 operating hours or 18 months, whichever comes first. The facility shall also sample the oxidation catalyst at least every 8,760 operating hours or 18 months, whichever comes first, to determine the VOC control efficiency. The facility must maintain records of the inspections and control efficiency results.

The annual reporting requirements are addressed in ADEM Admin. Code r. 335-3-14-.04(17)(e)4. The report should be submitted to the Director within 60 days after the end of each year during which records must be generated. The report shall contain the following:

(i) All information required by subparagraph (17)(e)1. of this Rule.
(ii) The name, address and telephone number of the major stationary source;
(iii) The annual emissions as calculated pursuant to subparagraph (17)(e)3. of this Rule.

The permittee shall maintain the records as required by ADEM Admin. Code r. 335-3-14-.04(17)(e)5. These records must be made available for review upon a request for inspection by the Department.

CHAPTER 335-3-16, MAJOR SOURCE OPERATING PERMITS

APC is currently operating under MSOP No. 503-1001. The proposed conversion project would contravene existing requirements in the current MSOP. Following the conversion, APC would have one year from startup of the unit to submit a significant modification application to the Department to incorporate the air permit into the Title V MSOP.

ADEM Admin. Code r. 335-3-16-.05, "Permit Content"

ADEM Admin. Code r. 335-3-16-.05(c) is cited as the authority to stipulate monitoring, recordkeeping, and reporting requirements as needed to determine continuous compliance with operating and emission standards. APC has stated that the boiler will be equipped with an oxidation catalyst system to control CO and VOC emissions. APC has stated that the oxidation catalyst has a design removal efficiency of 75% for CO. To demonstrate initial and continuous compliance, the oxidation catalyst shall be inspected for structural integrity, build up on the catalyst, and clogging of the catalyst medium at least every 8,760 operating hours or 18 months, whichever comes first, for a period of 10 years following the conversion project. The facility shall also sample the oxidation catalyst at least every 8,760 operating hours or 18 months, whichever comes first, to determine the CO control efficiency. The facility must maintain records of the inspections and control efficiency results. An annual report shall be submitted to the Department within 60 days after the end of each calendar year containing the annual CO emissions in tons per year.

CHAPTER 335-3-18, ACID RAIN PROGRAM-PERMITS REGULATION

The EPA regulations governing the Acid Rain Program – Permits Regulation (40 CFR Part 72) are incorporated by reference in ADEM Admin. Code r. 335-3-18. The Acid Rain Program is the national sulfur dioxide and nitrogen oxides air pollution control and emission reduction program. The unit is currently subject to the requirements of the Acid Rain Program; following the conversion, the unit will continue to comply with the requirements.

FEDERAL REGULATIONS

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR Part 60, Subpart Da, "NSPS for Electric Utility Steam Generating Units"

The Department reviewed 40 CFR Part 60, Subpart Da (NSPS for Electric Utility Steam Generating Units) for potential applicability. This subpart establishes PM, SO_2, and NO_x limits for units which were constructed, modified, or reconstructed after September 18, 1978 that can combust more than 250 MMBtu/hr heat input of fossil fuel. The unit is capable of combusting more than 250 MMBtu/hr heat input of fossil fuel but was constructed prior to September 18, 1978. Therefore, the unit is not currently subject to NSPS Da.

The Department reviewed the requirements of a modification, as defined in 40 CFR Part 60, Subpart A, to determine if the proposed project would be classified as a modification under NSPS Da. As stated in §60.14(h), no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purpose of this section (Part 60) provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section (Part 60) above the maximum hourly emissions achievable at that unit during the 5 years prior to the change. The proposed project would result in an increase of condensable PM emissions. However, as stated in §60.42Da(f)(1), if the unit 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 SO_2 or PM emissions, the unit is exempt from the PM emissions limits in NSPS Da. Therefore, no PM emission standards would be applicable to Unit 5 following the proposed project and would not be considered a regulated pollutant with respect to the definition of modification. The proposed project would not result in an increase of SO_2 or NO_x emissions above the maximum hourly rate achievable by Unit 5 during the 5 years prior to the conversion. Therefore, the proposed project would not be classified as a modification under NSPS Da.

The Department reviewed the requirements of reconstruction, as defined in 40 CFR Part 60, Subpart A, to determine if the proposed project would be classified as reconstruction under NSPS Da. As stated in §60.15(b), reconstruction means the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility, and it is technologically and economically feasible to meet the applicable standards. APC has stated that the proposed conversion project is expected to be below 50% of the fixed capital cost, and therefore would not be classified as reconstruction under NSPS Da.

40 CFR Part 60, Subpart TTTT, "NSPS for Greenhouse Gas Emissions for Electric Generating Units"

The Department reviewed 40 CFR Part 60, Subpart TTTT (NSPS for Greenhouse Gas Emissions for Electric Generating Units). This subpart applies to steam generating units that have a base load rating

greater than 250 MMBtu/hr of fossil fuel and serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system that commences construction after January 8, 2014, commences reconstruction after June 18, 2014, or commences modification after January 8, 2014, but on or before May 23, 2023. The proposed project is occurring after the applicability date of NSPS TTTT. Therefore, the unit would not be subject to the requirements of NSPS TTTT.

40 CFR Part 60, Subpart TTTTa, "NSPS for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units"

The Department reviewed 40 CFR Part 60, Subpart TTTTa (NSPS for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units) for potential applicability. This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) for modified coal-fired steam electric generating units that commences modification after May 23, 2023. Following the proposed project, Unit 5 would only fire natural gas and would no longer be capable of combusting coal. Therefore, the unit would not be subject to the requirements of Subpart TTTTa.

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP)

40 CFR Part 63, Subpart DDDDD, "NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters"

The Department reviewed 40 CFR Part 63, Subpart DDDDD (NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters) for potential applicability. This subpart applies to industrial, commercial, or institutional boilers or process heaters that are located at, or are a part of, a major source of HAP emissions. Following the conversion, the unit would meet the definition of a natural gas-fired electric utility steam generating unit, as defined in §63.10042. Therefore, following the conversion, the unit would not be subject to this subpart, as stated in §63.7491(a).

40 CFR Part 63, Subpart UUUUU, "NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units"

The unit is currently subject to the requirements of 40 CFR Part 63, Subpart UUUUU (NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units). The Department reviewed the applicability requirements of NESHAP UUUUU. Following the conversion, the unit would meet the definition of a natural gas-fired electric utility steam generating unit, as defined in §63.10042. Therefore, following the conversion, the unit would no longer be subject to this subpart, as stated in §63.9983(b).

40 CFR Part 63, Subpart JJJJJJ, "NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources"

The Department reviewed 40 CFR Part 63, Subpart JJJJJJ (NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources) for potential applicability. This subpart applies to industrial, commercial, or institutional boilers that are located at, or are part of, an area source of HAP emissions. APC is currently considered a major source with respect to HAP emissions. Therefore, the unit would not be subject to the requirements of NESHAP JJJJJJ.

COMPLIANCE ASSURANCE MONITORING (40 CFR PART 64)

Under 40 CFR Part 64, compliance assurance monitoring (CAM) applies to a pollutant-specific emissions unit at a major source required to obtain a Part 70 or 71 permit if it meets the following criteria: the unit is subject to a non-exempt emissions limit, uses a control device to achieve compliance with that limit,

and has potential pre-control device emissions of that pollutant that are equal to or greater than the major source threshold of 100 TPY for a criteria pollutant, 10 TPY for any single HAP, or 25 TPY for any combination of HAPs. Unit 5 is currently subject to the requirements of CAM for particulate matter emissions. The proposed conversion project was evaluated for CAM applicability. Following the conversion project, the unit would be subject to a PM emission limit, but the unit would not utilize a control device to achieve compliance with the limit. Therefore, the unit would no longer be subject to CAM following the conversion.

MANDATORY GREENHOUSE GAS REPORTING (40 CFR PART 98)

The Mandatory Greenhouse Gas Reporting (40 CFR Part 98) establishes monitoring, recordkeeping, and reporting requirements for the owners and operators of certain facilities that directly emit GHG, as listed in 40 CFR Part 98, Subpart A (General Provision). Note: On September 12, 2025, EPA proposed to permanently remove program obligations for 47 source categories, including electricity generation, of the Greenhouse Gas Reporting Program. If this action is finalized as proposed, the Permittee will no longer be subject to the requirements of the rule.

RECOMMENDATION

Based on the above analysis, upon receiving permitting fees and following resolution of any comments received during the 30-day public comment period, I recommend the following Air Permit be issued with the attached provisos (see Attachment No. 2).

PERMIT NUMBER	PERMIT DESCRIPTION
503-1001-X021	Unit 5 Natural Gas Fired Boiler with Oxidation Catalyst and Selective Catalytic Reduction (SCR)

Stephanie Dubay
Industrial Minerals Section
Energy Branch
Air Division

May 18, 2026
Date

File ID: 547 503-1001 097 05-18-2026 PSDD SJD X021 UNIT 5 NG CONVERSION PRELIM

ATTACHMENT NO. 1

Air Quality Analysis

EDWARD F. POOLOS
DIRECTOR

JEFFERY W. KITCHENS
DEPUTY DIRECTOR

KAY IVEY
GOVERNOR

Alabama Department of Environmental Management
adem.alabama.gov
1400 Coliseum Blvd. 36110-2400 ▪ Post Office Box 301463
Montgomery, Alabama 36130-1463
(334) 271-7700 ▪ FAX (334) 271-7950

December 10, 2025

MEMORANDUM

TO: Toshia Martin
Industrial Section
Energy Branch
Air Division

FROM: Jim Owen/Geoff Healan
Meteorological Section
Planning Branch
Air Division

SUBJECT: Air Dispersion Modeling for Alabama Power Barry Prevention of Significant Deterioration (PSD) Permit Application

ADEM has completed its review of an air quality modeling analysis performed by AECOM on behalf of Alabama Power Barry. The purpose of the analysis was to assess the impacts on air quality from emissions of particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) from a proposed modification at the number 5 electric generating unit located in Bucks, Alabama. An air quality analysis was performed for these pollutants to demonstrate that emissions from the proposed modification will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD Class II Increment.

AIR QUALITY MODELS:

The American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD), version 24142, was used in default mode for modeling all pollutants.

METEOROLOGICAL DATA:

The most recent 5 years (2019-2023) of surface and upper air meteorological data from the closest National Weather Service (NWS) office was used, including surface data from Mobile, Alabama, and upper air data from Slidell, Louisiana.

GOOD ENGINEERING PRACTICE ANALYSIS:

A Good Engineering Practice (GEP) Analysis was performed to assess possible building downwash effects. It was determined that the stacks modeled will be within 5L (the influence area) of one or more of the controlling buildings. Building downwash was considered for those sources in the modeling.

SCREENING MODELING:

The source modeled at the facility associated with the modification are provided in Appendix A of this memo. The table includes the stack parameters as well as emission rates for the modified source.

The base receptor grid consisted of a cartesian grid and discrete receptors placed along the ambient air boundary and was extended to the extent of the SIA (Significant Impact Area) for the respective pollutants. The receptor grids were generated using the following:

- 25 meter (m) spacing along the ambient air boundary,
- 100 m spacing from the ambient air boundary to 5 km,
- 250 m spacing from 5 km to 7 km,
- 500 m spacing from 7 km to 12 km,

All maximum predicted concentrations for all pollutants for all averaging periods were resolved to within 100-meter receptor spacing. Receptor terrain elevations were generated using the EPA AERMAP program developed from the USGS digital elevation model (DEM) using data from the 1/3 arc-second resolution map.

Table 3 lists the results of screening modeling performed for $PM_{2.5}$, and PM_{10}.

TABLE 3
Screening Modeling Results for NO_2, CO, $PM_{2.5}$, and PM_{10}, and SO_2

Pollutant	Averaging Period	Max. Conc. ($\mu g/m^3$)	Significance Level ($\mu g/m^3$)
$PM_{2.5}$	24-Hour	0.20	1.2
$PM_{2.5}$	Annual	0.02	0.13
PM_{10}	24-Hour	0.32	5.0
PM_{10}	Annual	0.03	1.0

The modeling results indicated that the maximum predicted concentrations did not exceeded their respective significance levels. Therefore, refined modeling was not required.

Also, during this initial screening modeling analysis, preconstruction monitoring requirements were addressed, and it was determined that preconstruction monitoring was not required for this application.

CLASS I AREA ANALYSIS:

The proposed facility is located approximately 132 km from the nearest Class I area, the Breton Wildlife Refuge. ADEM did not require a Class I analysis. Barry submitted an AQRV Applicability Request Form to the FLM. The FLM responded to this request in Appendix G.

CONCLUSION:

In conclusion, emissions of PM_{10}, $PM_{2.5}$ from the Alabama Power Barry project in Bucks, Alabama, are not expected to cause or contribute to any violation of the NAAQS or PSD Class II Increments.

Appendix A

Stack Characteristics

Source	PM2.5 Emissions (g/s)	PM_{10} Emissions (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Unit 5	7.17	7.17	182.88	407.04	23.39	7.62

ATTACHMENT NO. 2

Proposed Permit Provisos

Alabama Department of Environmental Management

AIR PERMIT

PERMITTEE: ALABAMA POWER COMPANY

FACILITY NAME: BARRY STEAM ELECTRIC GENERATING PLANT

LOCATION: BUCKS, MOBILE COUNTY, ALABAMA

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE OR DEVICE
503-1001-X021	Unit 5 Natural Gas Fired Boiler with Oxidation Catalyst and Selective Catalytic Reduction (SCR)

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, Ala. Code §§ 22-28-1 to 22-28-23, as amended, the Alabama Environmental Management Act, Ala. Code §§ 22-22A-1 to 22-22A-17, as amended, and rules and regulations adopted there under, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

ISSUANCE DATE: DRAFT

Alabama Department of Environmental Management

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. Each point of emission, which requires testing, will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. Unless otherwise specified in the unit-specific provisos of this permit, in case of shutdown of air pollution control equipment (which operates pursuant to this permit) for scheduled maintenance for a period greater than **1 hour,** the intent to shut down shall be reported to the Air Division at least 24 hours prior to the planned shutdown, **unless accompanied by the immediate shutdown of the emission source.**

6. Unless otherwise specified in the unit-specific provisos of this permit, in the event there is a breakdown of equipment in such a manner as to cause increased emissions of air contaminants which are above an applicable standard, the person responsible for such equipment shall notify the Air Division within an additional 24 hours or the next working day and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

7. All deviations from the requirements within this permit shall be reported to the Department within 48 hours of the deviation or by the next work day while providing a statement with regard to the date, time, duration, cause, and corrective actions taken to bring the source(s) back into compliance.

8. Unless otherwise specified, this process, including all air pollution control devices and capture systems for which this permit is issued shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

9. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

10. On completion of construction of the device(s) for which this permit is issued, written notification of the fact is to be submitted to the Chief of the Air Division. The notification shall indicate whether the device(s) was constructed as proposed in the application. The device(s) shall not be operated until authorization to operate is granted by the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

11. Prior to a date to be specified by the Chief of the Air Division in the authorization to operate, emission tests are to be conducted by persons familiar with and using the EPA Sampling Train and Test Procedure as described in the Code of Federal Regulations, Title 40, Part 60, for the following pollutants. Written tests results are to be reported to the Air Division within 30 days of completion of testing.

Particulates	(X)[1]	Carbon Monoxide	( )
Sulfur Dioxide	( )	Nitrogen Oxides	( )
Volatile Organic Compounds	(X)	Visible Emissions	( )

[1]Particulate matter testing should include filterable and condensable portions.

12. Emissions tests are to be conducted for the following pollutants at intervals not to exceed 60 months following the date of initial compliance testing. All test reports must be submitted to the Air Division within 30 days of completion of testing.

Particulates	(X)[1]	Carbon Monoxide	( )
Sulfur Dioxide	( )	Nitrogen Oxides	( )
Volatile Organic Compounds	( )		

[1]Particulate matter testing should include filterable and condensable portions.

13. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

14. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

15. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

16. This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.

17. Unless otherwise stated in this permit or an applicable regulation, the Air Division must be notified in writing at least 10 working days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.

    To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:

    (a) The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.

    (b) A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedure requires probe cleaning).

    (c) A description of the process(es) to be tested, including the feed rate, any operating parameter used to control or influence the operations, and the rated capacity.

    (d) A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.

    A pretest meeting may be held at the request of the source owner or the Department. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.

    All test reports must be submitted to the Air Division within 30 days of the actual completion of the test, unless an extension of time is specifically approved by the Air Division.

18. Records will be maintained of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the process equipment and any malfunction of the air pollution control equipment. These records will be kept in a permanent form suitable for inspection and will be retained for at least two years following the date of each occurrence.

19. Precautions shall be taken to prevent fugitive dust emanating from plant roads, grounds, stockpiles, screens, dryers, hoppers, ductwork, etc.

    Plant or haul roads and grounds will be maintained in the following manner so that dust will not become airborne. A minimum of one, or a combination, of the following methods shall be utilized to minimize airborne dust from plant or haul roads and grounds:

    (a) by the application of water any time the surface of the road is sufficiently dry to allow the creation of dust emissions by the act of wind or vehicular traffic;

    (b) by reducing the speed of vehicular traffic to a point below that at which dust emissions are created;

    (c) by paving;

    (d) by the application of binders to the road surface at any time the road surface is found to allow the creation of dust emissions;

    Should one, or a combination, of the above methods fail to adequately reduce airborne dust from plant or haul roads and grounds, alternative methods shall be employed, either

exclusively or in combination with one or all of the above control techniques, so that dust will not become airborne. Alternative methods shall be approved by the Department prior to utilization.

20. Any performance tests required shall be conducted and data reduced in accordance with the test methods and procedures contained in each specific permit condition unless the Director (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, or (3) approves the use of an alternative method, the results of which he has determined to be adequate for indicating whether a specific source is in compliance.

21. The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.

22. The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.

23. The permittee shall keep this permit under file or on display at all times at the site where the facility for which the permit is issued is located and shall make the permit readily available for inspection by any or all persons who may request to see it.

24. An annual compliance certification shall be submitted yearly by November 30, covering the reporting period of October 1 through September 30 of the previous calendar year, unless more frequent periods are specified according to the specific rule governing the source or required by the Department.

    (a) The compliance certification shall include the following:

        1. The identification of each term or condition of this permit that is the basis of the certification;
        2. The compliance status;
        3. The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with Rule 335-3-16-.05(c) (Monitoring and Recordkeeping Requirements);
        4. Whether compliance has been continuous or intermittent; and
        5. Such other facts as the Department may require in order to determine the compliance status of the source.

    (b) The compliance certification shall be submitted to:

Alabama Department of Environmental Management
Air Division
P.O. Box 301463
Montgomery, AL 36130-1463

Federally Enforceable Provisos	Regulations
Applicability	
1. This unit is part of a source subject to the applicable requirements of ADEM Admin. Code r. 335-3-16, "Major Source Operating Permits".	Rule 335-3-16-.03
2. This unit is subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.01, "Control of Particulate Emissions – Visible Emissions."	Rule 335-3-4-.01
3. This unit is subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.03, "Control of Particulate Emissions – Fuel Burning Equipment."	Rule 335-3-4-.03
4. This unit is subject to the applicable requirements of ADEM Admin. Code r. 335-3-5-.01, "Control of Sulfur Compound Emissions – Fuel Combustion".	Rule 335-3-5-.01
5. When an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions are incorporated as enforceable conditions of this permit.	Rule 335-3-16-.05(a)2
6. This unit is subject to the applicable provisions of the Cross-State Air Pollution Rule (CSAPR) found in ADEM Admin. Code r. 335-3-5-.06 through 335-3-5-.36 (including all applicable provisions of the SO_2 Group 2 Trading Program) and ADEM Admin. Code r. 335-3-8-.07 through 335-3-8-.70 (including all applicable provisions of the NO_X Annual and Seasonal Trading Programs).	Rules 335-3-5-.06 through 335-3-5-.36 and 335-3-8-.07 through 335-3-8-.70
7. This unit has enforceable standards identified in Emission Standards Provisos 5 and 6 in order to comply with the applicable requirements of ADEM Admin. Code r. 335-3-14-.04, "Air Permits Authorizing Construction in Clean Air Areas (Prevention of Significant Deterioration)".	Rule 335-3-14-.04 (PSD/BACT)
8. This unit is subject to the applicable requirements of ADEM Admin. Code r. 335-3-18, "Acid Rain Program" and 40 CFR Parts 72, 73, 75, and 76.	Rule 335-3-18 40 CFR Parts 72, 73, 75, and 76
9. This unit is subject to the applicable provisions of 40 CFR Part 98, "Mandatory Greenhouse Gas Reporting." If for any reason, the requirements of the Greenhouse Gas Reporting Program are no longer effective, such as a stay of regulations, the Permittee will no longer be subject to the requirements of the rule.	40 CFR Part 98
10. Upon completion of the conversion, this unit will no longer be subject to the provisions of 40 CFR Part 63, Subpart UUUUU, "National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units," because the unit will meet the definition of a natural gas-fired electric utility steam generating unit.	Rule 335-3-11-.06(124) 40 CFR 63.9983(b) and 63.10042

Federally Enforceable Provisos	Regulations
Emission Standards	
1. Emissions exceeding any allowances that the source lawfully holds under Title IV of the Clean Air Act or the regulations promulgated thereunder are prohibited.	Rule 335-3-16-.05(d)
2. This unit shall not discharge to the atmosphere particulate of an opacity greater than 20%, as determined by a six-minute average, except that during one six-minute period in any sixty (60) minute period, the unit may discharge into the atmosphere particulate of an opacity not greater than 40%.	Rule 335-3-4-.01(1)
3. Filterable particulate matter (PM) emissions from this unit shall not exceed 0.12 lb/MMBtu.	Rule 335-3-4-.03(1) Table 4-1
4. Sulfur dioxide (SO_2) emissions from this unit shall not exceed 1.8 lb/MMBtu.	Rule 335-3-5-.01(1)(a)
5. Particulate matter ($PM_{10}/PM_{2.5}$), including filterable and condensable, emissions from this unit shall not exceed 0.0075 lb/MMBtu (HHV) and 56.9 lb/hr.	Rule 335-3-14-.04 (PSD/BACT)
6. Once the conversion is complete, the Permittee shall combust only natural gas in this unit.	Rule 335-3-14-.04 (PSD/BACT)
7. The Permittee shall comply with all applicable provisions of the Cross-State Air Pollution Rule (CSAPR) found in ADEM Admin. Code r. 335-3-5-.06 through 335-3-5-.36 and ADEM Admin. Code r. 335-3-8-.07 through 335-3-8-.70.	Rule 335-3-5-.06 through 335-3-5-.36 and 335-3-8-.07 through 335-3-8-.70
8. This unit shall maintain the existing selective catalyst reduction (SCR) control system to reduce nitrogen oxide (NO_x) emissions. The SCR shall be operated, as necessary, and considering technology limitations, in order to comply with CSAPR.	Rule 335-3-18 Rule 335-3-8-.07 through 335-3-8-.70 40 CFR Part 76
9. This unit shall be equipped with an oxidation catalyst to reduce carbon monoxide (CO) and volatile organic compound (VOC) emissions. The oxidation catalyst shall be designed for use at all times that the unit is operating.	Rule 335-3-1-.04(1)
Compliance and Performance Test Methods and Procedures	
1. Compliance with the opacity standard in Emission Standards Proviso 2 shall be determined by EPA Reference Method 9 in 40 CFR Part 60, Appendix A-4.	Rule 335-3-1-.05(1)
2. Compliance with the filterable particulate matter (PM) emission limitation in Emission Standards Proviso 3 shall be determined by EPA Reference Method 5 in 40 CFR Part 60, Appendix A-3, or Method 17 in 40 CFR Part 60, Appendix A-6.	Rule 335-3-1-.05(1)

Federally Enforceable Provisos	Regulations
3. Compliance with the sulfur dioxide (SO_2) emission limitation in Emission Standards Proviso 4 shall be determined by EPA Reference Method 6 in 40 CFR Part 60, Appendix A-4.	Rule 335-3-1-.05(1)
4. Compliance with the condensable and filterable particulate matter ($PM_{10}/PM_{2.5}$) emission limitation in Emission Standards Proviso 5 shall be determined by EPA Reference Method 5 in 40 CFR Part 60, Appendix A-3 or Method 17 in 40 CFR Part 60, Appendix A-6, and EPA Reference Method 201A in 40 CFR Part 51, Appendix M, or Method 202 in 40 CFR Part 51, Appendix M.	Rule 335-3-1-.05(1)
5. The actual volatile organic compound (VOC) mass emission rate shall be determined by EPA Reference Method 25, 25A, or 25B in 40 CFR Part 60, Appendix A-7.	Rule 335-3-1-.05(1)
Emission Monitoring	
1. A continuous emissions monitoring system (CEMS) to measure nitrogen oxide (NO_x) emissions shall be installed, operated, maintained, and certified using the specifications and procedures of 40 CFR Part 75.	Rule 335-3-18 Rule 335-3-8-.33 Rule 335-3-8-.65 40 CFR Parts 72, 75, and 76
2. A continuous emissions monitoring system (CEMS) to measure carbon dioxide (CO_2) emissions or other approved continuous monitoring method under 40 CFR Part 75 shall be installed, operated, maintained, and certified using the specifications and procedures of 40 CFR Part 75.	Rule 335-3-18 40 CFR Parts 72 and 75
3. A sulfur dioxide continuous emissions monitoring system (CEMS) or other approved continuous monitoring method under 40 CFR Part 75 shall be operated, maintained, and certified using 40 CFR Part 75 procedures.	Rule 335-3-18 Rule 335-3-5-.31 40 CFR Parts 72, 73, and 75
4. The oxidation catalyst shall be inspected for structural integrity, build up on the catalyst, and clogging of the catalyst medium at least every 8,760 operating hours or 18 months, whichever comes first.	Rule 335-3-1-.04(1)
5. Sampling of the oxidation catalyst to determine carbon monoxide (CO) and volatile organic compound (VOC) control efficiency shall be performed at least every 8,760 operating hours or 18 months, whichever comes first.	Rule 335-3-1-.04(1)
Recordkeeping and Reporting Requirements	
1. For a period of 10 years following the completed conversion, the Permittee must calculate and maintain a record of the annual volatile organic compound (VOC) emissions, in tons per year on a calendar year basis. Emission calculations shall be based on initial testing and subsequent catalyst control efficiency data.	Rule 335-3-14-.04(17)(e)3.

Federally Enforceable Provisos	Regulations
2. For a period of 10 years following the completed conversion, the Permittee shall submit a report to the Department within 60 days after the end of each calendar year containing the following information for volatile organic compound (VOC) emissions: (a) All information required by ADEM Admin. Code r. 335-3-14-.04(17)(e)1.; (b) The name, address, and telephone number of the major stationary source; (c) The annual VOC emissions in tons per year; (d) Any other information that the permittee wishes to include in the report.	Rule 335-3-14-.04(17)(e)4.
3. For a period of 10 years following the completed conversion, the Permittee must calculate and maintain a record of the annual carbon monoxide (CO) emissions, in tons per year on a calendar year basis. Emission calculations shall be based on the catalyst control efficiency data.	Rule 335-3-16-.05(c)
4. For a period of 10 years following the completed conversion, the Permittee shall submit a report to the Department within 60 days after the end of each calendar year containing the annual carbon monoxide (CO) emissions in tons per year.	Rule 335-3-16-.05(c)
5. The Permittee must maintain records of the catalyst inspections and the sampling results indicating control efficiency of the catalyst.	Rule 335-3-1-.04(1)
6. The Permittee shall comply with the recordkeeping and reporting requirements of CSAPR found in Rules 335-3-5-.31, 335-3-5-.35, 335-3-8-.33, 335-3-8-.37, 335-3-8-.65 and 335-3-8-.69.	Rules 335-3-5-.31 335-3-5-.35 335-3-8-.33 335-3-8-.37 335-3-8-.65 335-3-8-.69
7. The Permittee shall comply with the recordkeeping and reporting requirements of the Mandatory Greenhouse Gas Reporting Rule in 40 CFR Part 98. If for any reason, the requirements of the Greenhouse Gas Reporting Program are no longer effective, such as a stay of regulations, the Permittee will no longer be subject to the requirements of the rule.	40 CFR Part 98