Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

February 2024

Facility Name: Talbot Energy Facility
City: Box Springs
County: Talbot
AIRS Number: 04-13-263-00013
Application Number: 767450
Date Application Received: September 7, 2023

Review Conducted by:
State of Georgia - Department of Natural Resources
Environmental Protection Division - Air Protection Branch
Stationary Source Permitting Program

Prepared by: Bradley Belflower – NOx Permitting Unit
Modeling Approved by: Olliander Beucler - Data and Modeling Unit
Reviewed and Approved by: Cynthia Dorrough – NOx Permitting Unit Coordinator Steve Allison – Stationary Source Permitting Program Manager James Boylan, Ph. D – Chief, Air Protection Branch

SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Talbot Energy Facility for a permit to modify four existing simple-cycle combustion turbines to burn fuel oil in addition to natural gas which is currently permitted for the turbines. The proposed project will modify combustion turbines T1, T2, T3, and T4, which are rated at 108 MW each, for the new fuel and increase the allowed operating hours of these turbines. In addition, two new fuel oil storage tanks with a capacity of 1.58 million gallons each and one new fire pump engine rated at 455 horsepower will be added to support the operation of the modified turbines.

The proposed project will result in an increase in emissions from the facility. The sources of these increases in emissions include the combustion turbines T1, T2, T3, and T4; fuel oil storage tanks ST2 and ST3; and fire pump engine FP1.

The modification of the Talbot Energy Facility due to this project will result in an emissions increase in particulate matter (PM), PM_{10}, $PM_{2.5}$, sulfur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), greenhouse gases (GHG), lead (Pb), and sulfuric acid mist (SAM). A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any increase was above the "significance" level. The PM, PM_{10}, $PM_{2.5}$, NO_x, VOC, CO, and GHG emissions increase were above the PSD significant level threshold.

The Talbot Energy Facility is located in Talbot County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$ and PM_{10}, NO_X, CO, and ozone (VOC).

The EPD review of the data submitted by Talbot Energy Facility related to the proposed modifications indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of PM, PM_{10}, $PM_{2.5}$, NOx, VOC, CO, and GHG, as required by federal PSD regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Talbot Energy Facility for the modifications necessary to modify four existing simple-cycle combustion turbines to burn fuel oil in addition to natural gas which is currently permitted for the turbines. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A. This Preliminary Determination also acts as a narrative for the Title V Permit.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On September 7, 2023, Talbot Energy Facility submitted an application for an air quality permit to modify four existing simple-cycle combustion turbines to burn fuel oil in addition to natural gas which is currently permitted for the turbines. The facility is located at 9125 Cartledge Road in Box Springs, Talbot County.

Table 1-1: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	✓	✓		
PM_{10}	✓	✓		
$PM_{2.5}$	✓	✓		
SO_2	✓			✓
VOC	✓	✓		
NO_x	✓	✓		
CO	✓	✓		
TRS	N/A			
H_2S	N/A			
Individual HAP	✓			✓
Total HAPs	✓			✓
Total GHGs	✓	✓		

Table 1-2 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a review of the "Permit" file(s) on the facility found in the Air Branch office.

Table 1-2: List of Current Permits, Amendments, and Off-Permit Changes

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-263-0013-V-07-0	02/01/2021	Title V Renewal

Based on the proposed project description and data provided in the permit application, the estimated incremental increases of regulated pollutants from the facility are listed in Table 1-3 below:

Table 1-3: Emissions Increases from the Project

Pollutant	Baseline Years	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	05/2015-04/2017	32.73	25	**Yes**
PM_{10}	05/2015-04/2017	107.81	15	**Yes**
VOC	05/2015-04/2017	44.97	40	**Yes**
NO_X	05/2015-04/2017	554.16	40	**Yes**
CO	01/2018-12/2019	314.18	100	**Yes**
SO_2	05/2015-04/2017	5.90	40	No
TRS	N/A	N/A	10	No

Pollutant	Baseline Years	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
Pb	05/2015-04/2017	0.017	0.6	No
Fluorides	N/A	N/A	3	No
H_2S	N/A	N/A	10	No
SAM	05/2015-04/2017	0.59	7	No

The definition of baseline actual emissions is the average emission rate, in tons per year, at which the emission unit actually emitted the pollutant during any consecutive 24-month period selected by the facility within the 10-year period immediately preceding the date a complete permit application was received by EPD. The net increases were calculated by subtracting the past actual emissions (based upon the annual average emissions from January 2018 to December 2019 for CO and May 2015 to April 2017 for all other pollutants) from the future projected actual emissions of the simple-cycle combustion turbines and associated emission increases from non-modified equipment. Table 1-4 details this emissions summary. The emissions calculations for Tables 1-3 and 1-4 can be found in detail in the facility's PSD application (see Appendix C of Application No. 767450). These calculations have been reviewed and approved by the Division.

Table 1-4: Net Change in Emissions Due to the Major PSD Modification

Pollutant	Increase from Turbines T1, T2, T3, and T4		New Units Increase (tpy)	Total Increase (tpy)
	Past Actual	Future Actual		
PM	9.96	42.68	0.01	32.73
PM_{10}	34.33	142.13	0.02	107.81
VOC	6.37	50.36	0.97	44.97
NO_X	73.90	627.29	0.77	554.16
CO	74.60	388.32	0.46	314.18
SO_2	1.50	7.17	0.23	5.90
TRS	N/A	N/A	N/A	N/A
Pb	N/A	N/A	N/A	N/A
Fluorides	N/A	N/A	N/A	N/A
H_2S	N/A	N/A	N/A	N/A
GHG	298,178	1,253,010	132.28	954,964
Lead	0	0.017	0	0.017
SAM	0.15	0.72	0.02	0.59

Based on the information presented in Tables 1-3 and 1-4 above, Talbot Energy Facility's proposed modification, as specified per Georgia Air Quality Application No. 767450, is classified as a major modification under PSD because the potential emissions of PM, PM_{10}, VOC, NOx, and CO.

Through its new source review procedure, EPD has evaluated Talbot Energy Facility's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

According to Application No. 767450, Talbot Energy Facility has proposed to modify four existing simple-cycle combustion turbines (T1, T2, T3, and T4) to burn fuel oil in addition to natural gas which is currently permitted for the turbines. The turbines, rated at 108 MW each, will be modified to add fuel oil burners and a water injection system to control NOx emissions during fuel oil combustion. The total permitted operating time for each turbine is also being increased to 4,200 hours per twelve-month period with 450 of these hours allowed to be during fuel oil combustion. The turbines are already equipped with CEMS for NOx and CO due to a previous PSD review (Application No. 15233). Once modified, the turbines will be subject to 40 CFR 60 Subpart KKKK and will cease to be subject to 40 CFR 60 Subpart GG. Two new 1,580,000-gallon fuel oil storage tanks will be constructed to provide fuel for the modified turbines. A 455-horsepower diesel-fired fire pump engine and water tank will provide water for fire suppression in case of emergency. The fire pump engine will be certified to meet the requirements of 40 CFR 60 Subpart IIII, and its hours of operation will be limited to 500 hours per twelve-month period per a request from Talbot Energy Facility.

The Talbot Energy Facility permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at http://epd.georgia.gov/psd112gnaa-nsrpcp-permits-database.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1), Construction Permit, requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1-.02(2)(b), Visible Emissions, limits the opacity of visible emissions from any air contaminant source, which is subject to some other emission limitation under 391-3-1-.02(2). The opacity of visible emissions from regulated sources may not exceed 40 percent under this general visible emission standard. It is expected that the opacity of all emissions from the turbines and fire pump engine will be well below 40% at all times.

Georgia Rule 391-3-1-.02(2)(d), Fuel-burning Equipment, limits opacity, particulate matter (PM), and nitrogen oxides (NOx) emissions from fuel-burning equipment. The turbines and fire pump engine do not meet the definition of "fuel-burning equipment" because their primary purpose of the turbines and engine is not to produce thermal energy. The turbines and fire pump engine are, therefore, not subject to Rule (d).

Georgia Rule 391-3-1-.02(2)(e), Particulate Matter Emission from Manufacturing Processes, commonly known as the process weight rate rule, limits PM emissions from manufacturing processes. The turbines, fire pump engine, and fuel oil storage tanks are not considered "manufacturing processes". Therefore, Rule (e) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(g), Sulfur Dioxide, applies to all "fuel burning" sources. The turbines and fire pump engine are "fuel burning" sources. Rule (g) limits the fuel burned in these sources to no more than 2.5 percent sulfur by weight. Other rules that these sources are subject to limit the fuel sulfur to amounts less than this rule, so Talbot Energy Facility will easily comply with Rule (g).

Georgia Rule 391-3-1-.02(2)(bb), Petroleum Liquid Storage, applies to storage tanks with capacities greater than 40,000 gallons storing a volatile petroleum liquid with a true vapor pressure greater than 1.52 psia. The true vapor pressure of the fuel oil to be stored in the new fuel oil storage tanks is less than 1.52 psia. Therefore Rule (bb) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(nn), VOC Emissions from External Floating Roof Tanks, applies to external floating roof tanks storing petroleum liquids having a capacity greater than 40,000 gallons. The new fuel oil storage tanks will be fixed roof storage tanks. Rule (nn), therefore, does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(tt), VOC Emissions from Major Sources, requires sources with potential emissions of VOC exceeding 25 tpy (or 100 tpy in some counties) in specific counties surrounding Atlanta to apply Reasonably Available Control Technology (RACT) to reduce those VOC emissions. Talbot County is not one of the counties listed in Rule (tt). Therefore, Rule (tt) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(vv), Volatile Organic Liquid Handling and Storage, requires the use of submerged fill pipes for stationary storage tanks greater than 4,000 gallons in specific counties surrounding Atlanta. Talbot County is not one of the counties listed in Rule (vv). Therefore, Rule (vv) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(yy), Emissions of Nitrogen Oxides from Major Sources, requires sources with potential emissions of NOx exceeding 25 tpy (or 100 typ in some counties) in specific counties surrounding Atlanta to apply Reasonably Available Control Technology (RACT) to reduce those NOx emissions. Talbot County is not one of the counties listed in Rule (yy). Therefore, Rule (yy) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(lll), NOx Emissions from Fuel-burning Equipment, establishes ozone-season NOx emissions limits for fuel-burning equipment with a maximum heat input rate between 10 MMBtu/hr and 250 MMBtu/hr located in specified counties surrounding Atlanta. Talbot County is not one of the counties listed in Rule (lll). Therefore, Rule (lll) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(mmm), NOx Emissions from Stationary Gas Turbines and Stationary Engines used to Generate Electricity, limits NOx emissions from small combustion turbines located in specific counties surrounding Atlanta. Talbot County is not one of the counties listed in Rule (mmm). Therefore, Rule (mmm) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(nnn), NOx Emissions from Large Stationary Gas Turbines, establishes ozone-season NOx emissions limits for large stationary gas turbines located in specified counties surrounding Atlanta. Talbot County is not one of the counties listed in Rule (nnn). Therefore, Rule (nnn) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(rrr), NOx Emissions from Small Fuel-Burning Equipment, applies to fuel burning equipment less than 10 MMBtu/hr located in specific counties surrounding Atlanta. The modified turbines and the fire pump engine do not meet the definition of fuel burning equipment, and Talbot County is not one of the counties listed in Rule (rrr). Therefore, Rule (rrr) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(sss), Multipollutant Control for Electric Utility Steam Generating Units, applies to certain electric utility steam generating units that are specified in this rule. None of the units at Talbot Energy Facility are listed in this rule. Therefore, Rule (sss) does not apply to Talbot Energy Facility.

Georgia Rule 391-3-1-.02(2)(uuu), SO_2 Emissions from Electric Utility Steam Generating Units, applies to certain electric utility steam generating units that are specified in this rule. None of the units at Talbot Energy Facility are listed in this rule. Therefore, Rule (uuu) does not apply to Talbot Energy Facility.

Federal Rule - PSD

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

Georgia has adopted a regulatory program for PSD permits, which the United States Environmental Protection Agency (EPA) has approved as part of Georgia's State Implementation Plan (SIP). This regulatory program is located in the Georgia Rules at 391-3-1-.02(7). This means that Georgia EPD issues PSD permits for new major sources pursuant to the requirements of Georgia's regulations. It also means that Georgia EPD considers, but is not legally bound to accept, EPA comments or guidance. A commonly used source of EPA guidance on PSD permitting is EPA's Draft October 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting (NSR Workshop Manual). The NSR Workshop Manual is a comprehensive guidance document on the entire PSD permitting process.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation

Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

EPA's NSR Workshop Manual includes guidance on the 5-step top-down process for determining BACT. In general, Georgia EPD requires PSD permit applicants to use the top-down process in the BACT analysis, which EPA reviews. The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines 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; and
Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

New Source Performance Standards

Subpart A (General Provisions)
Subpart A imposes generally applicable provisions for initial notifications, initial compliance testing, monitoring, and record keeping requirements. Since the modified turbines and the fire pump engine at Talbot Energy Facility will be subject to one or more New Source Performance Standard, they will also be subject to Subpart A.

Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators)
Subpart D applies to fossil fuel-fired steam generating units with heat input capacities greater than 250 MMBtu/hr for which construction or modification commenced after August 17, 1971. The turbines do not meet the definition of steam generating units. Therefore, Subpart D does not apply.

Subpart Da (Standards of Performance for Electric Utility Steam Generating Units)
Subpart Da applies electric utility steam generating units with heat input capacities greater than 250 MMBtu/hr for which construction, modification, or reconstruction commenced after September 18, 1978. The turbines do not meet the definition of steam generating units. Therefore, Subpart Da does not apply.

Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units)
Subpart Db applies to steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984. The turbines do not meet the definition of steam generating units. Therefore, Subpart Db does not apply.

Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)
Subpart Dc applies to steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989. The turbines do not meet the definition of steam generating units. Therefore, Subpart Dc does not apply.

Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984)
Subpart Kb applies to storage vessels containing volatile organic liquids (VOLs) with a capacity greater than 75 m^3 (approximately 19,800 gallons). The subpart, however, does not apply to vessels storing materials with a maximum true vapor pressure less than 3.5 kPa (approximately 0.51 pounds per square inch ambient). There are two proposed VOL vessels which will have storage greater than 75m^3. Since the vapor pressure of low sulfur fuel oil is below 3.5 kPa, the tanks are exempt from Subpart Kb.

Subpart GG (Standards of Performance for Stationary Gas Turbines)
Subpart GG applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, that are constructed, modified, or reconstructed after October 3, 1977. Turbines T1, T2, T3, and T4 are currently subject to Subpart GG. Following the modification of the turbines to allow for fuel oil combustion, these turbines will be subject to 40 CFR 60 Subpart KKKK. Per 40 CFR 60.4305(b), turbines that are subject to Subpart KKKK are exempt from the requirements of Subpart GG.

Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines)
Subpart IIII applies to stationary diesel-fired internal combustion (IC) engines and sets the emission standards for NOx, CO, PM and NMHC, along with limiting SO_2 through the use of low sulfur fuel. The regulation applies to the fire pump engine. The primary burden of the regulation falls on the IC engine manufacturers, rather than the owner/operators, since engine manufacturers must certify their 2007 model and later diesel-fired IC engines to the emission standards established in the rule, for all pollutants, for the same model year and maximum engine power. Starting with 2007 model year and later engines, owner/operators demonstrate compliance by purchasing engines certified by the manufacturer to meet the applicable emission standards and keep the manufacturer's documentation showing the engines are certified.

Subpart KKKK, Standards of Performance for Stationary Combustion Turbines
Subpart KKKK applies to stationary combustion turbines with a heat input at peak load of 10 MMBtu/hr or greater that were constructed, reconstructed, or modified after February 18, 2005. Turbines T1, T2, T3, and T4 each have a heat input greater than 10 MMBtu/hr. The physical change to these turbines necessary to add fuel oil combustion capability constitutes a modification under this rule. Therefore, Subpart KKKK will apply to these turbines. Subpart KKKK includes following limitations for NOx and SO_2 from the turbines.

Subpart KKKK Limits:	
NOx, firing natural gas	15 ppmv at 15% oxygen (0.43 lb/MWh)
NOx, firing fuel oil	42 ppmv at 15% oxygen (1.3 lb/MWh)
SO2	0.90 lb/MWh

Alternatively, the source may choose to comply with the Subpart KKKK limit on fuel-sulfur content equal to 0.060 lb SO_2/MMBtu. This is approximately equivalent to a sulfur concentration in oil of 0.05 wt.% or 500 ppmw. The turbines already meet a NOx limit of 12 ppmv at 15% oxygen while combusting natural gas. A water injection system will be added to the turbines to control NOx emissions during fuel oil combustion.

Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units)
Subpart TTTT applies to any fossil fuel fired steam generating unit, Integrated Gasification Combined Cycle (IGCC) unit, or stationary combustion turbine constructed after January 8, 2014 or reconstructed after June 8, 2014 and to any steam generating unit or IGCC modified after June 8, 2014, provided that unit has a base load rating greater than 250 MMBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to the grid. Turbines T1, T2, T3, and T4 are potentially subject to this rule. The only emission units subject to Subpart TTTT are units that commenced construction after January 8, 2014, or that commenced reconstruction after June 18, 2014 (see 40 CFR 60.5509). The modified turbines will not meet the definition of reconstruction, because the fixed capital cost of the new components will not exceed 50% of the fixed capital cost to construct a new comparable turbine. Subpart TTTT, therefore, does not apply.

National Emissions Standards For Hazardous Air Pollutants

Subpart A (General Provisions)
Subpart A imposes generally applicable requirements for initial notifications, initial compliance testing, monitoring, and record keeping requirements. Since the fire pump engine will be subject to one or more MACT standards, it will also be subject to Subpart A.

Subpart YYYY (National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines)
Subpart YYYY regulates stationary combustion turbines located at major sources of HAP emissions. Talbot Energy Facility is an area source of HAP emissions. Therefore, Subpart YYYY does not apply.

Subpart ZZZZ (National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines)
Subpart ZZZZ applies to new, reconstructed, or existing stationary reciprocating internal combustion engines (RICE) at a major source or area source for HAP emissions. Talbot Energy Facility is an area source of HAP emissions, and the fire pump engine will be subject to Subpart ZZZZ. Per 40 CFR 60.6590(c), a new stationary RICE will comply with Subpart ZZZZ by complying with 40 CFR 60 Subpart IIII.

Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters)
Subpart DDDDD (Major Source Boiler MACT) regulates boilers and process heaters at major sources of HAP emissions. Talbot Energy Facility is an area source of HAP emissions. Therefore, Subpart DDDDD does not apply.

Subpart UUUUU (National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units)
Subpart UUUUU applies to electric utility steam generating units (EGUs) that combust coal or oil. The turbines do not meet the definition of steam generating unit. Therefore, Subpart UUUUU does not apply.

Subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources)
Subpart JJJJJJ (Area Source Boiler MACT) regulates boilers at area sources of HAP emissions. The turbines do not meet the definition of boiler, therefore, Subpart JJJJJJ does not apply.

State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from turbines T1, T2, T3, and T4 associated with the proposed project would most likely result from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Although other units may potentially be subject to CAM upon renewal of the Title V operating permit, such units are not being modified under the proposed project and need not be considered for CAM applicability at this time. Therefore, this applicability evaluation only addresses turbines T1, T2, T3, and T4. These turbines will employ water injection to control NOx emissions during fuel oil combustion which is, therefore, potentially subject to CAM. The current permit and this amendment use a CEMS as a continuous compliance determination method for NOx from the turbines which exempts the NOx limit from CAM [see 40 CFR 64.2(b)(1)(vi)]. No other air pollution control devices are employed for the modified emission units; therefore, the CAM requirements are not triggered by the proposed modification.

Federal Rules – Acid Rain Program

The Acid Rain regulations apply to turbines T1, T2, T3, and T4 because they each have a nameplate capacity greater than 25 MW and they are to supply electricity for sale, whether wholesale or retail. The existing permit already contains the appropriate conditions to implement the Acid Rain Program (see Section 7.9 of the current permit).

Federal Rules – Cross State Air Pollution Rule (CSAPR)

The Cross State Air Pollution Rule (CSPAR)regulations apply to turbines T1, T2, T3, and T4 because they each have a nameplate capacity greater than 25 MW and they are to supply electricity for sale, whether wholesale or retail. The existing permit already contains the appropriate conditions to implement CSAPR (see Section 7.15 of the current permit).

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: NOx, CO, PM, VOC, and GHG.

Combustion Turbines T1, T2, T3, and T4 – Background

Combustion Turbines 1 through 4 (Source Code T1, T2, T3, and T4) are simple-cycle natural gas-fired combustion turbines rated at 108 MW each. The turbines are Siemens-Westinghouse V84.2 and use lean premix technology, also known as dry low-NOx combustion technology, to minimize NOx emissions. The turbines will be modified to allow for fuel oil combustion.

Combustion Turbines T1, T2, T3, and T4 – NOx Emissions

Applicant's Proposal

Talbot Energy Facility included their analysis for NOx BACT from the combustion turbines in Section 5.6 of Application 767450. Eight potential NOx control technologies were identified: (1) lean premix (aka dry low-NOx), (2) water or steam injection, (3) good combustion practices, (4) EMX™/SCONOX™, (5) selective catalytic reduction (SCR), (6) SCR with ammonia oxidation catalyst (aka Zero-Slip), (7) selective noncatalytic reduction (SNCR), and (8) multi-function catalyst (aka METEOR™).

Each of these control technologies are addressed as follows:

Dry Low-NOx (DLN)

The lean premix technology (aka dry low-NOx) uses lean mixtures of air and fuel to significantly reduce the formation of NOx in the combustion turbine. The fuel and air are pre-mixed prior to combustion zone resulting in a uniform fuel/air mixture that prevents localized high temperature regions within the combustor area. Because the peak temperatures in the combustion turbines are reduced, the formation of thermal NOx is, likewise, reduced. DLN is currently used on the combustion turbines at Talbot Energy Facility while firing natural gas. During fuel oil combustion, however, the fuel and air cannot be adequately mixed for DLN to work. DLN, therefore, is technically feasible during natural gas combustion, but is not technically feasible during fuel oil combustion.

Water or Steam Injection

Water or steam is introduced into the flame area of the turbine combustor. The injected water or steam acts as a heat sink and, thereby reduces the peak flame temperature in the turbine. The reduced peak flame temperature results in a reduction in the formation of thermal NO_x. Water/steam injection can reduce NOx emissions by over 60%, but the lower average temperature within the combustor may produce higher levels of CO and VOC as a result of incomplete combustion. Water/stream injection results in a decrease in combustion efficiency and an increase in maintenance requirements due to wear. An increase in mass flow does result in an increase in power production. Water injection cannot be used in conjunction with DLN because it results in unstable combustion and an increase in CO emissions. Water injection, therefore, is not technically feasible during natural gas combustion, but is technically feasible during fuel oil combustion.

Good Combustion Practices

As stated in Section 5.6.2.3 of Application 767450, "Good combustion practices are those, in the absence of control technology, which allow the equipment to operate as efficiently as possible. The operating parameters most likely to affect NOx emissions include ambient temperature, fuel characteristics, and air-to-fuel ratios." Good combustion practices are technically feasible for either fuel.

EM_X™/$SCONO_X$™

EM_X™ (the second-generation of the $SCONO_X$™ NOX Absorber Technology) is utilizes a coated oxidation catalyst to remove NOx, CO, and VOC without a reagent (such as ammonia). The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. The catalyst, however, is susceptible to fouling by sulfur if the sulfur content of the flue gas is high. Control efficiencies of 78% reduction of NOx and outlet concentrations of 2.0 ppm NOx have been reported. From Section 5.6.3.5 of Application 767450, "As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_X™/$SCONO_X$™ catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation. Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines." EM_X™/$SCONO_X$™, therefore, is not technically feasible.

Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment process in which ammonia or urea is injected into the exhaust gas upstream of a catalyst bed. The NOx in the gas steam and injected ammonia (or urea) reacts on the catalyst to form nitrogen gas and water vapor. As stated in Section 5.6.2.5 of Application 767450, "When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent." The optimal temperatures for SCR 480°F to 800°F. One additional problem for SCR is "ammonia slip" which is the release of unreacted ammonia to the atmosphere. Exhaust gases from simple-cycle turbines are typically in excess of 1000°F which is well above the optimal temperature for the catalyst. SCR, therefore, is not technically feasible.

SCR with Ammonia Oxidation Catalyst (aka Zero-Slip™)

SCR with Ammonia Oxidation Catalyst (Zero-Slip™) is a refinement of the standard SCR technology. The Zero-Slip™ technology consists of a second bed of catalyst to further react NOx with the ammonia. NOx emissions are similar to standard SCR with less ammonia slip. Zero-Slip™ has not been demonstrated on a large scale, utility-sized turbine. Zero-Slip™, therefore, is not technically feasible.

Selective Noncatalytic Reduction (SNCR)

In SNCR, urea or ammonia is injected into the exhaust gas stream without a catalyst being present. The injected urea or ammonia reacts with NOx in the gas stream to produce nitrogen gas, carbon dioxide, and water. SNCR systems typically achieve NOx reductions of 30 to 50 percent. Optimal temperatures for SNCR, however, range from 1,600 to 2,000°F. Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NOx. The optimal temperature for SNCR is above the exhaust temperature from combustion turbines. SNCR, therefore, is not technically feasible.

Multi-Function Catalyst (aka METEOR™)
Per Section 5.6.2.8 of Application 767450, METEOR™ is a multi-pollutant post-combustion control technology that uses a catalyst and ammonia to reduce NOx emissions, similar to standard SCR systems. The catalyst, however, also reduces CO and VOC emissions. Per Section 5.6.2.8 of Application 767450, "The ability of the METEOR™ catalyst to reduce NO_X emissions is on par with more traditional SCR designs." METEOR™ has similar technical considerations as standard SCR. METEOR™, therefore, is not technically feasible.

The only NOx control technologies that are technically feasible during natural gas combustion are good combustion practices and DLN, and the only NOx control technologies that are technically feasible during fuel oil combustion are good combustion practices and water injection. Therefore, these are the technologies chosen for BACT for NOx on the combustion turbines. Talbot Energy Facility proposes BACT limits of 12.0 ppmdv corrected to 15% oxygen during natural gas combustion and 42.0 ppmdv corrected to 15% oxygen during fuel oil combustion. Each of these limits are based on a three-hour average and CEMS will be used to show compliance with the limits.

The BACT limits of 12.0 ppmdv corrected to 15% oxygen and 42.0 ppmdv corrected to 15% oxygen do not apply during periods of startup or shutdown. Emissions during periods of startup and shutdown are different than emissions during steady state operation. To account for the increased emissions during startup and shutdown, a secondary BACT limit of 156.8 tons per twelve-consecutive month period is proposed to apply at all times including startup and shutdown.

EPD Review – NOx Control

Natural Gas
The Division reviewed the RBLC for large (>25 MW) natural gas-fired simple cycle combustion turbines in the last five years (since 2018). Turbines that are obviously not simple cycle turbines (e.g., description included HRSG or duct burner) and turbines that are not used for power generation were eliminated from the list. Washington County Power in Sandersville, Georgia is not in the RBLC, but has been added to the list. The resulting combustion turbines are summarized in Table 4-1. These results show that the lowest achievable NOx emission rate from a natural gas-fired simple cycle combustion turbine using dry low NOx combustors is 9 ppm corrected to 15% oxygen. BACT, however, requires that the limit is achievable. Talbot Energy Facility submitted data (see Application 767450, Figure 5-1) that showed the actual emissions from turbines T1, T2, T3, and T4 from 2020 to 2022. This data shows that, although the emissions are often less than 9 ppm corrected to 15% oxygen, emissions of up to 12 ppm corrected to 15% oxygen occur frequently.

Table 4-1: Summary of BACT Determinations for NOx; Large (>25MW) Natural Gas-Fired Simple Cycle Combustion Turbines (2018 to present)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
AK-0085	08/13/2020	386 MMBtu/hr	15 ppm @ 15% O_2	DLN combustors and Good Combustion Practices
AL-0329	09/21/2021	229 MW	9 ppm @ 15% O_2	
LA-0327	05/23/2018	2201 MMBtu/hr	9 ppm @ 15% O_2	Pipeline quality natural gas & dry-low-NOx burners
LA-0331	09/21/2018	927 MMBtu/hr	9 ppm	Dry Low NOx Combustor Design, Good Combustion Practices, and Natural Gas Combustion.
MI-0441	12/21/2018	667 MMBtu/hr	25 ppm	Dry low NOx burners (DLNB) and good combustion practices.
MI-0447	01/07/2021	667 MMBtu/hr	25 ppm	DLNB and good combustion practices.
TN-0187	08/31/2022	465.8 MMBtu/hr	5 ppm @ 15% O_2	dry low-NOx burners selective catalytic reduction
TX-0833	01/26/2018	920 MW	9 ppm	Dry low NOx burners
TX-0900	08/17/2020		9 ppm @ 15% O_2	Equipped with dry-low NOx burners with best management practices and good combustion practices. Minimize the duration of startup and shutdown events to less than 60 minutes per event. Limit MSS by 140 lb/hr maximum allowable emission rate for each turbine.
TX-0933	11/17/2021		9 ppm @ 15% O_2	Low NOx burners and SCR
WV-0028	03/13/2018	167.8 MW	69 lb/hr	Dry LNB
Washington County Power, LLC				
N/A	11/17/2021	169 MW	9 ppm @ 15% O_2	Low NOx burners

Fuel Oil

The Division reviewed the RBLC for large (>25 MW) fuel oil-fired simple cycle combustion turbines in the last ten years (since 2013). Turbines that are obviously not simple cycle turbines (e.g., description included HRSG or duct burner) and turbines that are not used for power generation were eliminated from the list. Washington County Power in Sandersville, Georgia is not in the RBLC, but has been added to the list. The resulting combustion turbines are summarized in Table 4-2. These results show that the lowest achievable NOx emission rate from a fuel oil-fired simple cycle combustion turbine using water injection is 42 ppm corrected to 15% oxygen.

Table 4-2: Summary of BACT Determinations for NOx; Large (>25MW) Fuel Oil-Fired Simple Cycle Combustion Turbines (2013 to present)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
NJ-0086	08/26/2016		5 ppm @ 15% O_2	SCR and water injection
OH-0353	03/07/2013		2255.9 lb/hr	
TX-0699	12/16/2014			Good combustion practices
TX-0794	04/07/2016	171 MW	42 ppm @ 15% O_2	DLN, water injection
Washington County Power, LLC				
N/A	11/17/2021	169 MW	42 ppm @ 15% O_2	Water injection

Conclusion – NOx Control
A NOx limit of 12.0 ppmdv corrected to 15% oxygen, based on good combustion practices and DLN is BACT for the turbines while burning natural gas. A NOx limit of 42.0 ppmdv corrected to 15% oxygen, based on good combustion practices and water injection is BACT for the turbines while burning fuel oil. A limit for NOx of 156.8 tons per twelve-consecutive months during all periods of operation, including startup and shutdown, is a secondary BACT limit. The BACT selection for turbines T1, T2, T3, and T4 is summarized below in Table 4-10:

Combustion Turbines T1, T2, T3, and T4 – PM/PM_{10}/$PM_{2.5}$ Emissions

Applicant's Proposal
Talbot Energy Facility included their analysis for PM/PM_{10}/$PM_{2.5}$ BACT from the combustion turbines in Section 5.7 of Application 767450. Six potential PM/PM_{10}/$PM_{2.5}$ control technologies were identified: (1) multiclone, (2) wet scrubber, (3) electrostatic precipitator (ESP), (4) baghouse, (5) low sulfur fuel, and (6) good combustion and operating practices.

Each of these control technologies are addressed as follows:

Multiclone
As stated in Section 5.7.2.1 of Application 767450, "Multicyclones consist of several small cyclones operating in parallel. … The control efficiency range for high efficiency single cyclones is 30 - 90% for PM_{10} and 20 - 70% for $PM_{2.5}$." Cyclones are generally used in conjunction prior to other PM control devices such as baghouses or ESPs. Due to the relatively low PM concentration in the exhaust stream from turbines, a multiclone is not technically feasible.

Wet Scrubber
Wet scrubbers use direct interception of particulate matter by liquid (usually water) droplets. Venturi scrubbers can have control efficiencies from 70% to 99%. Inlet gas temperatures to wet scrubbers are usually less than 750°F. Due to the relatively low PM concentration in the exhaust stream from turbines and the high exhaust temperature, a wet scrubber is not technically feasible.

Electrostatic Precipitator (ESP)
Per Section 5.7.2.3 of Application 767450, "An ESP removes particles from an air stream by electrically charging the particles then passing them through a force field that causes them to migrate to an oppositely charged collector plate." The collection efficiency for PM can be as high as 99.99%. Inlet temperatures can be as high as 1,300°F. Due to the relatively low PM concentration in the exhaust stream from turbines, a ESP is not technically feasible.

Baghouse (Fabric Filter)
Per Section 5.8.2.4 of Application 767450, "A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Particulate laden gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the

baghouse." Baghouses can achieve control efficiencies of up to 99.99% for PM. Inlet temperatures are typically less than 500°F. Higher temperatures degrade the fabric material and shorten the fabric's life. High moisture environments are not appropriate for baghouses due to condensation plugging bags. Due to the relatively low PM concentration in the exhaust stream from turbines and the high exhaust temperature, a baghouse is not technically feasible.

Low Sulfur Fuel

As stated in Section 5.7.2.5 of Application 767450, "Combusting pipeline-quality natural gas with an inherently low sulfur content reduces particulate emissions compared to other available fuels as there is less potential to form SO_2 and H_2SO_4. Similarly, use of ultra-low sulfur diesel fuel oil also minimizes SO_2 and H_2SO_4 formation leading to lower particulate emissions compared to other fuel oils. Low sulfur fuel is technically feasible.

Good Combustion and Operating Practices

As stated in Section 5.7.2.6 of Application 767450, "Good combustion and operating practices imply that the unit is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible. A properly operated combustion unit will minimize the formation of particulate emissions due to incomplete combustion. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios and periodic tuning." Good combustion and operating practices are technically feasible.

The only $PM/PM_{10}/PM_{2.5}$ control technologies that are technically feasible are low sulfur fuel and good combustion and operating practices. Therefore, these control technologies were chosen for BACT for $PM/PM_{10}/PM_{2.5}$ from the combustion turbines. Talbot Energy Facility proposes BACT limits of 0.0137 lb/MMBtu (equivalent to 16.2 lb/hr) during natural gas combustion and 0.017 lb/MMBtu (equivalent to 23.2 lb/hr) during fuel oil combustion. Each of these limits are based on a three-hour average. Performance tests will be used to show compliance with the limits.

EPD Review – $PM/PM_{10}/PM_{2.5}$ Control

Natural Gas

EPD reviewed the RBLC for large (>25 MW) natural gas-fired simple cycle combustion turbines in the last five years (since 2018). Turbines that are obviously not simple cycle turbines (e.g., description included HRSG or duct burner) and turbines that are not used for power generation were eliminated from the list. Washington County Power in Sandersville, Georgia is not in the RBLC, but has been added to the list. The resulting combustion turbines are summarized in Table 4-3. These results show that the proposed limit of 0.0137 lb/MMBtu is among the lowest achievable particulate matter limits from a natural gas-fired simple cycle combustion turbine using good combustion practices.

Table 4-3: Summary of BACT Determinations for $PM/PM_{10}/PM_{2.5}$; Large (>25MW) Natural Gas-Fired Simple Cycle Combustion Turbines (2018 to present)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
AK-0085	08/13/2020	386 MMBtu/hr	0.007 lb/MMBtu	Good Combustion Practices and burning clean fuels (NG)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
AL-0329	09/21/2021	229 MW	0.008 lb/MMBtu	
LA-0327	05/23/2018	2201 MMBtu/hr	6.3 lb/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)
LA-0331	09/21/2018	927 MMBtu/hr	8 lb/hr	Exclusive Combustion of Fuel Gas and Good Combustion Practices, Including Proper Burner Design.
MI-0441	12/21/2018	667 MMBtu/hr	4.5 lb/hr	Pipeline quality natural gas, inlet air conditioning and good combustion practices.
MI-0447	01/07/2021	667 MMBtu/hr	4.5 lb/hr	Pipeline quality natural gas, inlet air conditioning and good combustion practices.
MI-0454	12/20/2022	667 MMBtu/hr	4.5 lb/hr	Pipeline quality natural gas, inlet air conditioning and good combustion practices.
TN-0187	08/31/2022	465.8 MMBtu/hr	3.65 lb/hr	Good combustion design and operating practices and the use of low sulfur fuel
TX-0833	01/26/2018	920 MW	11.81 tons/yr	Use of pipeline quality natural gas and good combustion practices.
TX-0933	11/17/2021		0.0075 lb/MMBtu	Good combustion practices and the use of gaseous fuel
WV-0028	03/13/2018	167.8 MW	15.09 lb/hr	Inlet air filtration.
Washington County Power, LLC				
N/A	11/17/2021	169 MW	24.2 lb/hr 0.0137 lb/MMBtu	Good combustion practices

Fuel Oil

The Division reviewed the RBLC for large (>25 MW) fuel oil-fired simple cycle combustion turbines in the last ten years (since 2013). Turbines that are obviously not simple cycle turbines (e.g., description included HRSG or duct burner) and turbines that are not used for power generation were eliminated from the list. Washington County Power in Sandersville, Georgia is not in the RBLC, but has been added to the list. The resulting combustion turbines are summarized in Table 4-4. These results show that the proposed limit of 0.017 lb/MMBtu is among the lowest achievable particulate matter limits from a natural gas-fired simple cycle combustion turbine using good combustion practices.

Table 4-4: Summary of BACT Determinations for PM/PM_{10}/$PM_{2.5}$; Large (>25MW) Fuel Oil-Fired Simple Cycle Combustion Turbines (2013 to present)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
NJ-0086	08/26/2016		14 lb/hr	Use of ULSD, a clean burning fuel
OH-0353	03/07/2013		5.2 lb/hr	
TX-0794	04/07/2016	171 MW	9.8 lb/hr	Combustor designed for complete combustion and therefore minimizes emissions
NJ-0086	08/26/2016		14 lb/hr	Use of ULSD, a clean burning fuel
TX-0794	04/07/2016	171 MW	9.8 lb/hr	Combustor designed for complete combustion and therefore minimizes emissions

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
Washington County Power, LLC				
N/A	11/17/2021	169 MW	26.8 lb/hr 0.0142 lb/MMBtu	Good combustion practices

Conclusion – $PM/PM_{10}/PM_{2.5}$ Control

A $PM/PM_{10}/PM_{2.5}$ limit 0.0137 lb/MMBtu (equivalent to 16.2 lb/hr) during natural gas combustion and 0.017 lb/MMBtu (equivalent to 23.2 lb/hr) during fuel oil combustion is BACT for the turbines. These limits are based on using low sulfur fuels and good combustion and operating practices. The BACT selection for turbines T1, T2, T3, and T4 is summarized below in Table 4-10.

Combustion Turbines T1, T2, T3, and T4 – CO Emissions

Applicant's Proposal

Talbot Energy Facility included their analysis for CO BACT from the combustion turbines in Section 5.8 of Application 767450. Three potential CO control technologies were identified: (1) oxidation catalyst, (2) EM_X™/$SCONO_X$™, and (3) combustion process design and good combustion practices.

Each of these control technologies are addressed as follows:

Oxidation Catalyst

As stated in Section 5.8.2.1 of Application 767450, "An oxidation catalyst is a post-combustion control technology that utilizes a catalyst to oxidize CO at lower temperatures. The addition of a catalyst to the basic thermal oxidation process accelerates the rate of oxidation by adsorbing oxygen from the air stream and CO in the waste stream onto the catalyst surface to react to form CO_2 and H_2O." Per Section 5.8.3.1 of Application 767450, Oxidation catalyst typically operates between 600°F and 800°F, but the exhaust from a simple-cycle turbine is typically greater than 1000°F. The exhaust, however, could be cooled, so oxidation catalyst is considered technically feasible. The estimated cost of using oxidation catalysts to control CO emissions is $22,970 per ton (see Appendix D of Application 767450). Oxidation catalysts are deemed to not be cost effective for the control of CO emissions from the turbines.

EM_X™/$SCONO_X$™

EM_X™/$SCONO_X$™ was summarized in more detail as a potential NOx control technology. As noted in that section, this technology removes both NOx, CO, and VOC from the exhaust stream. Also as noted, this technology has never been applied to larger plants with full scale operation, and the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines." EM_X™/$SCONO_X$™, therefore, is not technically feasible.

Combustion Process Design and Good Combustion Practices

As stated in Section 5.8.2.3 of Application 767450, "To minimize incomplete combustion and the resulting formation of CO, this control technology includes proper equipment design, proper operation, and good combustion practices. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperature as well as turbulence to mitigate incomplete mixing. Generally, the effect of combustion zone temperature and residence time on CO emissions is the opposite of their effect on NOx emissions. Accordingly, it is critical to optimize oxygen availability with input air, while controlling temperature to minimize NOx formation." Combustion process design and good combustion practices are technically feasible for either fuel.

The only CO control technologies that are technically feasible are oxidation catalyst and combustion process design and good combustion practices. Oxidation catalyst was determined to not be cost effective for the control of CO from the turbines. Therefore, combustion process design and good combustion practices were chosen for BACT for CO from the combustion turbines. Talbot Energy Facility proposes BACT limits of 8.0 ppmdv corrected to 15% oxygen during natural gas combustion and 15.0 ppmdv corrected to 15% oxygen during fuel oil combustion. Each of these limits are based on a three-hour average and CEMS will be used to show compliance with the limits.

The BACT limits of 8.0 ppmdv corrected to 15% oxygen and 15.0 ppmdv corrected to 15% oxygen do not apply during periods of startup or shutdown. Emissions during periods of startup and shutdown are different than emissions during steady state operation. To account for the increased emissions during startup and shutdown, a secondary BACT limit of 97.1 tons per twelve-consecutive month period is proposed to apply at all times including startup and shutdown.

EPD Review – CO Control

Natural Gas

The Division reviewed the RBLC for large (>25 MW) natural gas-fired simple cycle combustion turbines in the last five years (since 2018). Turbines that are obviously not simple cycle turbines (e.g., description included HRSG or duct burner) and turbines that are not used for power generation were eliminated from the list. Washington County Power in Sandersville, Georgia is not in the RBLC, but has been added to the list. The resulting combustion turbines are summarized in Table 4-5. These results show that the proposed limit of 8 ppm corrected to 15% oxygen is among the lowest achievable CO emission rate from a natural gas-fired simple cycle combustion turbine using good combustion practices.

Table 4-5: Summary of BACT Determinations for CO; Large (>25MW) Natural Gas-Fired Simple Cycle Combustion Turbines (2018 to present)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
AK-0085	08/13/2020	44 MW	15 ppm @ 15% O_2	Good Combustion Practices and burning clean fuels (NG)
AL-0329	09/21/2021	229 MW	9 ppm @ 15% O_2	
LA-0327	05/23/2018	2201 MMBtu/hr	6 ppm @ 15% O_2	Good combustion practices & use of pipeline quality natural gas
LA-0331	09/21/2018	927 MMBtu/hr	25 ppm @ 15% O_2	Proper Equipment Design, Proper Operation, and Good Combustion Practices.
MI-0441	12/21/2018	667 MMBtu/hr	9 lb/hr	Dry low NOx burners and good combustion practices.

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
MI-0447	01/07/2021	667 MMBtu/hr	9 lb/hr	Dry low NOx burners and good combustion practices
MI-0454	12/20/2022	667 MMBtu/hr	9 lb/hr	Dry low NOx burners and good combustion practices.
TN-0187	08/31/2022	465.8 MMBtu/hr	5 ppm @ 15% O_2	oxidation catalyst
TX-0833	01/26/2018	920 MW	9 ppm	Dry low NOx burners
WV-0028	03/13/2018	167.8 MW	33.9 lb/hr	Combustion Controls
Washington County Power, LLC				
N/A	11/17/2021	169 MW	9 ppm @ 15% O_2	Good Combustion Practices

Fuel Oil

The Division reviewed the RBLC for large (>25 MW) fuel oil-fired simple cycle combustion turbines in the last ten years (since 2013). Turbines that are obviously not simple cycle turbines (e.g., description included HRSG or duct burner) and turbines that are not used for power generation were eliminated from the list. Washington County Power in Sandersville, Georgia is not in the RBLC, but has been added to the list. The resulting combustion turbines are summarized in Table 4-6. These results show that the proposed limit of 15 ppm corrected to 15% oxygen is among the lowest achievable CO emission rate from a fuel oil-fired simple cycle combustion turbine using good combustion practices.

Table 4-6: Summary of BACT Determinations for CO; Large (>25MW) Fuel Oil-Fired Simple Cycle Combustion Turbines (2013 to present)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
NJ-0086	08/26/2016		5 ppm @ 15% O_2	Oxidation Catalyst
OH-0353	03/07/2013		504.1 lb/hr	
TX-0794	04/07/2016	171 MW	20 ppm @ 15% O_2	Combustor designed for complete combustion and therefore minimizes emissions
Washington County Power, LLC				
N/A	11/17/2021	169 MW	20 ppm @ 15% O_2	Good combustion practices

Conclusion – CO Control

A CO limit of 8.0 ppmdv corrected to 15% oxygen while burning natural gas and 15.0 ppmdv corrected to 15% oxygen while burning fuel oil is BACT for the turbines. These limits are based on combustion process design and good combustion practices. A limit for CO of 97.1 tons per twelve-consecutive months during all periods of operation, including startup and shutdown, is a secondary BACT limit. The BACT selection for turbines T1, T2, T3, and T4 is summarized below in Table 4-10.

Combustion Turbines T1, T2, T3, and T4 – VOC Emissions

Applicant's Proposal

Talbot Energy Facility included their analysis for VOC BACT from the combustion turbines in Section 5.9 of Application 767450. Three potential CO control technologies were identified: (1)

oxidation catalyst, (2) EM_X™/$SCONO_X$™, and (3) combustion process design and good combustion practices.

Each of these control technologies are addressed as follows:

Oxidation Catalyst
As stated in Section 5.9.2.1 of Application 767450, "An oxidation catalyst is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed prompting the VOC to react with oxygen present in the exhaust stream, converting to carbon dioxide and water vapor. The overall control efficiency of such systems on VOC constituents is dependent on the individual VOC components. For example, research completed by U.S. EPA as part of MACT rulemakings found that control of formaldehyde emissions typically exceeds 90%, but other pollutants such as benzene may not see any beneficial reductions. Hence, the overall range of VOC control can vary substantially." Per Section 5.9.3.1 of Application 767450, Oxidation catalyst typically operates between 600°F and 800°F, but the exhaust from a simple-cycle turbine is typically greater than 1000°F. The exhaust, however, could be cooled, so oxidation catalyst is considered technically feasible. The estimated cost of using oxidation catalyst to control VOC emissions is $177,109 per ton (see Appendix D of Application 767450). Oxidation catalyst is deemed to not be cost effective for the control of VOC emissions from the turbines.

EM_X™/$SCONO_X$™
EM_X™/$SCONO_X$™ was summarized in more detail as a potential NOx control technology. As noted in that section, this technology removes NOx, CO, and VOC from the exhaust stream. Also as noted, this technology has never been applied to larger plants with full scale operation, and the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines." EM_X™/$SCONO_X$™, therefore, is not technically feasible.

Combustion Process Design and Good Combustion Practices
As stated in Section 5.9.2.3 of Application 767450, "To minimize incomplete combustion and the resulting formation of VOC, this control technology includes proper equipment design, proper operation, and good combustion practices. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperature as well as turbulence to mitigate incomplete mixing. Proper operation and good combustion practices provide additional VOC control via the use of gaseous fuels for good mixing and proper combustion techniques such as optimizing the air to fuel ratio." Combustion process design and good combustion practices are technically feasible for either fuel.

The only VOC control technologies that are technically feasible are oxidation catalyst and combustion process design and good combustion practices. Oxidation catalyst was determined to not be cost effective for the control of VOC from the turbines. Therefore, combustion process design and good combustion practices were chosen for BACT for VOC from the combustion turbines. Talbot Energy Facility proposes BACT limits of 2.0 ppmdv corrected to 15% oxygen during natural gas combustion and 5.0 ppmdv corrected to 15% oxygen during fuel oil combustion. Each of these limits are based on a three-hour average and performance tests will be used to show compliance with the limits.

EPD Review – VOC Control

Natural Gas

The Division reviewed the RBLC for large (>25 MW) natural gas-fired simple cycle combustion turbines in the last five years (since 2018). Turbines that are obviously not simple cycle turbines (e.g., description included HRSG or duct burner) and turbines that are not used for power generation were eliminated from the list. Washington County Power in Sandersville, Georgia is not in the RBLC, but has been added to the list. The resulting combustion turbines are summarized in Table 4-7. These results show that the proposed limit of 2.0 ppm corrected to 15% oxygen is among the lowest achievable VOC emission rate from a natural gas-fired simple cycle combustion turbine using good combustion practices.

Table 4-7: Summary of BACT Determinations for VOC; Large (>25MW) Natural Gas-Fired Simple Cycle Combustion Turbines (2018 to present)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
AK-0085	08/13/2020	386 MMBtu/hr	0.0022 lb/MMBtu	Good Combustion Practices and burning clean fuels (NG)
LA-0327	05/23/2018	2201 MMBtu/hr		Good combustion practices & use of pipeline quality natural gas
LA-0331	09/21/2018	927 MMBtu/hr	1.4 ppm	Proper Equipment Design, Proper Operation, and Good Combustion Practices.
LA-0349	07/10/2018	540 MMBtu/hr	0.002 lb/MMBtu	Good Combustion Practices and Use of low sulfur facility fuel gas
MI-0441	12/21/2018	667 MMBtu/hr	5 lb/hr	Good combustion practices.
MI-0447	01/07/2021	667 MMBtu/hr	5 lb/hr	Good combustion practices
MI-0454	12/20/2022	667 MMBtu/hr	5 lb/hr	Good combustion practices.
TX-0833	01/26/2018	920 MW	2 ppm	Good combustion practices
TX-0933	11/17/2021		1.7 ppm	Oxidization catalyst, good combustion practices and the use of gaseous fuel
Washington County Power, LLC				
N/A	11/17/2021	169 MW	2.0 ppm @ 15% O_2	Good combustion practices

Fuel Oil

The Division reviewed the RBLC for large (>25 MW) fuel oil-fired simple cycle combustion turbines in the last ten years (since 2013). Turbines that are obviously not simple cycle turbines (e.g., description included HRSG or duct burner) and turbines that are not used for power generation were eliminated from the list. Washington County Power in Sandersville, Georgia is not in the RBLC, but has been added to the list. The resulting combustion turbines are summarized in Table 4-8. These results show that the proposed limit of 5.0 ppm corrected to 15% oxygen is among the lowest achievable VOC emission rate from a fuel oil-fired simple cycle combustion turbine using good combustion practices.

Table 4-8: Summary of BACT Determinations for VOC; Large (>25MW) Fuel Oil-Fired Simple Cycle Combustion Turbines (2013 to present)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
NJ-0086	08/26/2016		4.5 ppm @ 15%O_2	Oxidation catalyst
OH-0353	03/07/2013		135.6 lb/hr	
TX-0794	04/07/2016	171 MW	3.3 lb/hr	combustor designed for complete combustion and therefore minimizes emissions
Washington County Power, LLC				
N/A	11/17/2021	169 MW	5 ppm @ 15% O_2	Good combustion practices

Conclusion – VOC Control

A VOC limit of 2.0 ppmdv corrected to 15% oxygen while burning natural gas and 5.0 ppmdv corrected to 15% oxygen while burning fuel oil is BACT for the turbines. These limits are based on combustion process design and good combustion practices. The BACT selection for turbines T1, T2, T3, and T4 is summarized below in Table 4-10.

Combustion Turbines T1, T2, T3, and T4 – GHG Emissions

Applicant's Proposal

Talbot Energy Facility included their analysis for greenhouse gases (GHG) BACT from the combustion turbines in Section 5.10 of Application 767450. For the turbines, three gases are considered GHG: (1) carbon dioxide (CO_2), (2) methane (CH_4), and (3) nitrous oxide (N_2O). Each of these gases have their own potential control technologies. Three potential GHG control technologies were identified: (1) carbon capture and storage (CCS) for CO_2, (2) N_2O catalyst for N_2O, and (3) efficient turbine operation and good combustion, operating, and maintenance practices for CO_2, CH_4, and N_2O. Note that oxidation catalyst was not considered a potential technology for CH4 because "oxidizing the very low concentrations of CH_4 present in the combustion turbine exhaust would require much higher temperatures, residence times, and catalyst loadings than those offered commercially for CO oxidation catalysts." (Section 5.10.2.1 of Application 767450)

Each of these control technologies are addressed as follows:

Carbon Capture and Storage (CCS)

As stated in Section 5.10.1.1.1 of Application 767450, "CCS, also known as CO_2 sequestration, involves the cooling, separation, and capture of CO_2 emissions from flue gas prior to being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components needed for CCS must be technically feasible: carbon capture and compression, transport, and storage." Talbot Energy Facility concluded that CCS is not technically feasible for CO_2, however, "for the sake of discussion", the cost effectiveness of CCS was determined. As noted in Appendix D of Application 767450, the total plant capital cost without CCS is $780/kW, and the total plant capital cost with CCS is $1686/kW. These costs mean that adding CCS would more than double the cost of the facility compared to not adding CCS. CCS, therefore, is deemed to not be cost effective for CO_2 control.

N$_2$O Catalyst
As stated in Section 5.10.3.1 of Application 767450, "N_2O catalysts are a potential control option, as these have been used in nitric/adipic acid plant applications to minimize N_2O emissions. Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NOx catalyst." The N_2O concentrations from combustion turbines are very low. N_2O catalysts for the concentrations from combustion turbines are not available. N_2O catalyst, therefore, is not technically feasible.

Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices
As stated in Section 5.10.1.1.2 of Application 767450, "Efficient turbine operation coupled with good combustion, operating, and maintenance practices are a potential control option for optimizing the fuel efficiency of the combustion turbines. Combustion turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. Furthermore, the turbine systems are sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation." Efficient turbine operation and good combustion, operating, and maintenance practices is technically feasible for the control of GHG from combustion turbines.

The only GHG control technology that is technically feasible and cost effective is Efficient turbine operation and good combustion, operating, and maintenance practices. Talbot Energy Facility proposes BACT limit of 313,253 tons CO_2e per twelve-consecutive months during all periods of operation. Fuel usage records will be used to show compliance with this limit.

EPD Review – GHG Control
The Division reviewed the RBLC for large (>25 MW) simple cycle combustion turbines in the last five years (since 2018). Turbines that are obviously not simple cycle turbines (e.g., description included HRSG or duct burner) and turbines that are not used for power generation were eliminated from the list. Washington County Power in Sandersville, Georgia is not in the RBLC, but has been added to the list. The resulting combustion turbines are summarized in Table 4-9. These results show that good combustion practices is the only practical control for GHG emissions. Emissions on a tons per year basis vary widely based on turbine size and allowed operating hours.

Table 4-9: Summary of BACT Determinations for GHG (CO_2e); Large (>25MW) Simple Cycle Combustion Turbines (2018 to present)

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
AK-0085	08/13/2020	386 MMBtu/hr	117.1 lb/MMBtu	Good combustion practices and clean burning fuel (NG)
AL-0329	09/21/2021	229 MW	120 lb/MMBtu	
LA-0327	05/23/2018	2201 MMBtu/hr	50 kg/GJ	Facility-wide energy efficiency measures , such as improved combustion measures, and use of pipeline quality natural gas.

RBLC ID	Permit Issuance Date	Turbine Size	Limit(s)	Controls
LA-0331	09/21/2018	927 MMBtu/hr	1,426,146 tons/yr	Exclusively combust low carbon fuel gas, good combustion practices, good operation and maintenance practices, and insulation
MI-0454	12/20/2022	667 MMBtu/hr	318,404 tons/yr	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
TN-0187	08/31/2022	465.8 MMBtu/hr	120 lb/MMBtu	Efficient turbine operation and good combustion practices
TX-0900	08/17/2020		1514 lb/MWh	Best management practices and good combustion practices, clean fuel
TX-0933	11/17/2021			Good combustion practices and the use of gaseous fuel
WV-0028	03/13/2018	167.8 MW		Use of natural gas & use of GE 7FA.004
Washington County Power, LLC				
N/A	11/17/2021	169 MW	387,497 tons/yr	Good combustion practices

<u>Conclusion – GHG Control</u>

A GHG limit of 313,253 tons CO_2e per twelve-consecutive months is BACT for the turbines based on combustion efficient turbine operation coupled with good combustion, operating, and maintenance practices. The BACT selection for turbines T1, T2, T3, and T4 is summarized below in Table 4-10.

Table 4-10: BACT Summary for the Turbines T1, T2, T3, and T4

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Natural Gas	Good Combustion Practices and DLN	12.0 ppmdv @ 15% O_2	3 hours	CEMS
NOx	Fuel Oil	Good Combustion Practices and Water Injection	42.0 ppmdv @ 15% O_2	3 hours	CEMS
NOx	Both	Good Combustion Practices, DLN, and Water Injection	156.8 tons	12 consecutive months	CEMS
PM/PM_{10}/ $PM_{2.5}$	Natural Gas	Good Combustion and Operating Practices	0.0137 lb/MMBtu (equivalent to 16.2 lb/hr)	3 hours	Performance Test
PM/PM_{10}/ $PM_{2.5}$	Fuel Oil	Low Sulfur Fuel and Good Combustion and Operating Practices	0.017 lb/MMBtu (equivalent to 23.2 lb/hr)	3 hours	Performance Test
CO	Natural Gas	Combustion Process Design and Good Combustion Practices	8.0 ppmdv @ 15% O_2	3 hours	CEMS
CO	Fuel Oil	Combustion Process Design and Good Combustion Practices	15.0 ppmdv @ 15% O_2	3 hours	CEMS
CO	Both	Combustion Process Design and Good Combustion Practices	97.1 tons	12 consecutive months	CEMS

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Natural Gas	Combustion Process Design and Good Combustion Practices	2.0 ppmdv @ 15% O_2	3 hours	Performance Test
VOC	Fuel Oil	Combustion Process Design and Good Combustion Practices	5.0 ppmdv @ 15% O_2	3 hours	Performance Test
GHG	Both	Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices	313,253 tons CO_2e	12 consecutive months	Fuel Usage Records

Fire Pump Engine – Background

The Fire Pump Engine (Source Code FP1) is 455 horsepower diesel-fired engine. The fire pump engine along with a water tank will provide water for fire suppression in case of emergency.

Fire Pump Engine – NOx Emissions

Applicant's Proposal
Talbot Energy Facility included their analysis for NOx BACT from the fire pump engine in Section 5.12 of Application 767450. Four potential NOx control technologies were identified: (1) purchase of certified NSPS Subpart IIII engine, (2) good combustion practices, (3) limitations on hours of operation, and (4) selective catalytic reduction (SCR). All of these technologies were presumed to be technically feasible. The purchase of a certified engine and using good combustion practices are already required by other requirements. Talbot Energy Facility has requested a hours of operation limit of 500 hours per twelve-consecutive month period for the fire pump engine. As stated in Section 5.12.5 of Application 767450, "Given the capital costs involved with installation of add-on controls for reduction of less than 1 tpy of emissions, a traditional cost effectiveness analysis would demonstrate a substantial $/ton pollutant removed value, concluding installation of control is not cost effective."

Talbot Energy Facility proposes BACT limits of 4.0 g/kW-hr (3.0 g/hp-hr) in terms of NMHC NOx. Note that this is the same limit for new fire pump engines in Table 4 of 40 CFR 60 Subpart IIII. Compliance will be shown by purchasing an engine certified to meet the requirements of Subpart IIII and by operating the engine consistent with the requirements of Subpart IIII.

EPD Review – NOx Control
The Division reviewed the RBLC for small (<500 HP) diesel-fired engines in the last five years (since 2018). Engines that were used for purposes other than fire pump engine were removed from the list. The resulting combustion turbines are summarized in Table 4-11. These results show that using engines certified to meet 40 CFR 60 Subpart IIII is the most common control for NOx.

Table 4-11: Summary of BACT Determinations for NOx; Small (<500 HP) Diesel-Fired Engines used as Fire Pump Engines (2018 to present)

RBLC ID	Permit Issuance Date	Engine Size	Limit(s)	Controls
FL-0371	06/07/2021	2.46 MMBtu/hr	4 g/kW-hr	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.
IL-0130	12/31/2018	420 hp	4 g/kW-hr	
IL-0133	07/29/2022	320 hp	4 g/kW-hr	
LA-0370	04/27/2020	1.1 MMBtu/hr	1.15 lb/hr	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII
MI-0433	06/29/2018	300 hp	3 g/hp-hr	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0434	03/22/2018	250 hp	3 g/hp-hr	Good combustion practices.
MI-0435	07/16/2018	399 hp	4 g/kW-hr	State of the art combustion design.
MI-0445	11/26/2019	1.66 MMBtu/hr	3 g/hp-hr	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0451	06/23/2022	300 hp	3 g/hp-hr	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	06/23/2022	300 hp	3 g/hp-hr	Good Combustion Practices and meeting NSPS Subpart IIII requirements
NE-0064	11/21/2022	510 hp	2.38 g/hp-hr	
OH-0376	02/09/2018	250 hp	1.6 lb/hr	Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	04/19/2018	320 hp	2.12 lb/hr	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	12/21/2018	402 hp	2.64 lb/hr	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual
OH-0387	09/20/2022	275 hp	4 g/kW-hr	Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
TX-0846	09/23/2018	214 kW	0.4 g/kW-hr	Meets EPA Tier 4 requirements
WI-0300	09/01/2020	282 hp	3 g/hp-hr	Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturer's recommendations.
WI-0302	02/28/2020	290 hp	3.64 lb/hr	Only use diesel fuel oil with a sulfur content of no greater than 0.0015% by weight

<u>Conclusion – NOx Control</u>

A NMHC+NOx limit of 4.0 g/kW-hr (3.0 g/hp-hr) is BACT for the fire pump engine based on the purchase of certified NSPS Subpart IIII engine, good combustion practices, and limitations on hours of operation. The BACT selection for the fire pump engine is summarized below in Table 4-16.

Fire Pump Engine – $PM/PM_{10}/PM_{2.5}$ Emissions

Applicant's Proposal

Talbot Energy Facility included their analysis for $PM/PM_{10}/PM_{2.5}$ BACT from the fire pump engine in Section 5.13 of Application 767450. Six potential $PM/PM_{10}/PM_{2.5}$ control technologies were identified: (1) purchase of certified NSPS Subpart IIII engine, (2) good combustion practices, (3) use of clean fuel, (4) limitations on hours of operation, (5) catalyzed diesel particulate filters (CDPF), and (6) diesel oxidation catalyst (DOC). All of these technologies were presumed to be technically feasible. The purchase of a certified engine and using good combustion practices are already required by other requirements. Talbot Energy Facility has requested a hours of operation limit of 500 hours per twelve-consecutive month period for the fire pump engine. As stated in Section 5.13.5 of Application 767450, "Given the capital costs involved with installation of add-on controls for reduction of significantly less than 1 tpy of emissions, a traditional cost effectiveness analysis would demonstrate a substantial $/ton pollutant removed value, concluding installation of control is not cost effective."

Talbot Energy Facility proposes BACT limits of 0.20 g/kW-hr (0.15 g/hp-hr). Note that this is the same limit for new fire pump engines in Table 4 of 40 CFR 60 Subpart IIII. Compliance will be shown by purchasing an engine certified to meet the requirements of Subpart IIII and by operating the engine consistent with the requirements of Subpart IIII.

EPD Review – $PM/PM_{10}/PM_{2.5}$ Control

The Division reviewed the RBLC for small (<500 HP diesel-fired engines in the last five years (since 2018). Engines that were used for purposes other than fire pump engine were removed from the list. The resulting combustion turbines are summarized in Table 4-12. These results show that using engines certified to meet 40 CFR 60 Subpart IIII is the most common control for PM.

Table 4-12: Summary of BACT Determinations for $PM/PM_{10}/PM_{2.5}$; Small (<500 HP) Diesel-Fired Engines used as Fire Pump Engines (2018 to present)

RBLC ID	Permit Issuance Date	Engine Size	Limit(s)	Controls
FL-0371	06/07/2021	2.46 MMBtu/hr	0.2 g/kW-hr	
IL-0130	12/31/2018	420 hp	0.2 g/kW-hr	
IL-0133	07/29/2022	320 hp	0.2 g/kW-hr	
LA-0370	04/27/2020	1.1 MMBtu/hr	0.04 lb/hr	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII
MI-0433	06/29/2018	300 hp	0.15 g/hp-hr	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0435	07/16/2018	399 hp	0.2 g/kW-hr	State of the art combustion design
MI-0445	11/26/2019	1.66 MMBtu/hr	0.15 g/hp-hr	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0451	06/23/2022	300 hp	0.15 g/hp-hr	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	06/23/2022	300 hp	0.15 g/hp-hr	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
NE-0064	11/21/2022	510 hp	0.15 g/hp-hr	

RBLC ID	Permit Issuance Date	Engine Size	Limit(s)	Controls
OH-0376	02/09/2018	250 hp	0.1 lb/hr	Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	04/19/2018	320 hp	0.11 lb/hr	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	12/21/2018	402 hp	0.13 lb/hr	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual
OH-0387	09/20/2022	275 hp	0.2 g/kW-hr	Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
TX-0846	09/23/2018	214 kW	0.02 g/kW-hr	Meets EPA Tier 4 requirements
WI-0300	09/01/2020	282 hp	0.15 g/hp-hr	Operation limited to 500 hours/year, sulfur content of diesel fuel oil fired may not exceed 15 ppm and operate and maintain according to the manufacturer's recommendations.
WI-0302	02/28/2020	290 hp	0.11 lb/hr	Good combustion practices, use diesel fuel oil with sulfur content of no greater than 0.0015% by weight.

Conclusion – PM/PM_{10}/$PM_{2.5}$ Control

A limit of 0.20 g/kW-hr (0.15 g/hp-hr) is BACT for the fire pump engine based on the purchase of certified NSPS Subpart IIII engine, good combustion practices, and limitations on hours of operation. The BACT selection for the fire pump engine is summarized below in Table 4-16.

Fire Pump Engine – CO Emissions

Applicant's Proposal

Talbot Energy Facility included their analysis for CO BACT from the fire pump engine in Section 5.14 of Application 767450. Five potential CO control technologies were identified: (1) purchase of certified NSPS Subpart IIII engine, (2) good combustion practices, (3) limitations on hours of operation, (4) catalyzed diesel particulate filters (CDPF), and (5) diesel oxidation catalyst (DOC). All of these technologies were presumed to be technically feasible. The purchase of a certified engine and using good combustion practices are already required by other requirements. Talbot Energy Facility has requested a hours of operation limit of 500 hours per twelve-consecutive month period for the fire pump engine. As stated in Section 5.14.5 of Application 767450, "Given the capital costs involved with installation of add-on controls for reduction of less than 1 tpy of emissions, a traditional cost effectiveness analysis would demonstrate a substantial $/ton pollutant removed value, concluding installation of control is not cost effective."

Talbot Energy Facility proposes BACT limits of 3.5 g/kW-hr (2.6 g/hp-hr). Note that this is the same limit for new fire pump engines in Table 4 of 40 CFR 60 Subpart IIII. Compliance will be shown by purchasing an engine certified to meet the requirements of Subpart IIII and by operating the engine consistent with the requirements of Subpart IIII.

EPD Review – CO Control

The Division reviewed the RBLC for small (<500 HP) diesel-fired engines in the last five years (since 2018). Engines that were used for purposes other than fire pump engine were removed from the list. The resulting combustion turbines are summarized in Table 4-13. These results show that using engines certified to meet 40 CFR 60 Subpart IIII is the most common control for CO.

Table 4-13: Summary of BACT Determinations for CO; Small (<500 HP) Diesel-Fired Engines used as Fire Pump Engines (2018 to present)

RBLC ID	Permit Issuance Date	Engine Size	Limit(s)	Controls
FL-0371	06/07/2021	2.46 MMBtu/hr	3.5 g/kW-hr	
IL-0130	12/31/2018	420 hp	3.5 g/kW-hr	
IL-0133	07/29/2022	320 hp	3.5 g/kW-hr	
LA-0370	04/27/2020	1.1 MMBtu/hr	0.4 lb/hr	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII
MI-0433	06/29/2018	300 hp	2.6 g/hp-hr	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0435	07/16/2018	399 hp	3.5 g/kW-hr	State of the art combustion design.
MI-0445	11/26/2019	1.66 MMBtu/hr	2.6 g/hp-hr	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0451	06/23/2022	300 hp	2.6 g/hp-hr	Good combustion practices and meeting NSPS Subpart IIII requirements
MI-0452	06/23/2022	300 hp	2.6 g/hp-hr	Good Combustion Practices and meeting NSPS Subpart IIII requirements
OH-0376	02/09/2018	250 hp	1.4 lb/hr	Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	04/19/2018	320 hp	1.83 lb/hr	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	12/21/2018	402 hp	2.31 lb/hr	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual
OH-0387	09/20/2022	275 hp	3.5 g/kW-hr	Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
TX-0846	09/23/2018	214 kW	3.58 g/kW-hr	Meets EPA Tier 4 requirements
WI-0300	09/01/2020	282 hp	2.6 g/hp-hr	Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturer's recommendations.
WI-0302	02/28/2020	290 hp	0.33 lb/hr	Good combustion practices

Conclusion – CO Control

A limit of 3.5 g/kW-hr (2.6 g/hp-hr) is BACT for the fire pump engine based on the purchase of certified NSPS Subpart IIII engine, good combustion practices, and limitations on hours of operation. The BACT selection for the fire pump engine is summarized below in Table 4-16.

Fire Pump Engine – VOC Emissions

Applicant's Proposal
Talbot Energy Facility included their analysis for VOC BACT from the fire pump engine in Section 5.15 of Application 767450. Five potential VOC control technologies were identified: (1) purchase of certified NSPS Subpart IIII engine, (2) good combustion practices, (3) limitations on hours of operation, (4) catalyzed diesel particulate filters (CDPF), and (5) diesel oxidation catalyst (DOC). All of these technologies were presumed to be technically feasible. The purchase of a certified engine and using good combustion practices are already required by other requirements. Talbot Energy Facility has requested a hours of operation limit of 500 hours per twelve-consecutive month period for the fire pump engine. As stated in Section 5.15.5 of Application 767450, "Given the capital costs involved with installation of add-on controls for reduction of significantly less than 1 tpy of emissions, a traditional cost effectiveness analysis would demonstrate a substantial $/ton pollutant removed value, concluding installation of control is not cost effective."

Talbot Energy Facility proposes BACT limits of 4.0 g/kW-hr (3.0 g/hp-hr) in terms of NMHC NOx. Note that this is the same limit for new fire pump engines in Table 4 of 40 CFR 60 Subpart IIII. Compliance will be shown by purchasing an engine certified to meet the requirements of Subpart IIII and by operating the engine consistent with the requirements of Subpart IIII.

EPD Review – VOC Control
The Division reviewed the RBLC for small (<500 HP) diesel-fired engines in the last five years (since 2018). Engines that were used for purposes other than fire pump engine were removed from the list. The resulting combustion turbines are summarized in Table 4-14. These results show that using engines certified to meet 40 CFR 60 Subpart IIII and good combustion practices are common controls for VOC.

Table 4-14: Summary of BACT Determinations for VOC; Small (<500 HP) Diesel-Fired Engines used as Fire Pump Engines (2018 to present)

RBLC ID	Permit Issuance Date	Engine Size	Limit(s)	Controls
MI-0433	06/29/2018	300 hp	0.75 lb/hr	Good combustion practices
MI-0435	07/16/2018	399 hp	0.13 lb/hr	State of the art combustion design.
MI-0451	06/23/2022	300 hp	0.75 lb/hr	Good combustion practices.
MI-0452	06/23/2022	300 hp	0.75 lb/hr	Good Combustion Practices
NE-0064	11/21/2022	510 hp	0.62 g/hp-hr	
OH-0377	04/19/2018	320 hp	2.12 lb/hr	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII

Conclusion – VOC Control
A NMHC+NOx limit of 4.0 g/kW-hr (3.0 g/hp-hr) is BACT for the fire pump engine based on the purchase of certified NSPS Subpart IIII engine, good combustion practices, and limitations on hours of operation. The BACT selection for the fire pump engine is summarized below in Table 4-16.

Fire Pump Engine – GHG Emissions

Applicant's Proposal

Talbot Energy Facility included their analysis for GHG BACT from the fire pump engine in Section 5.16 of Application 767450. As stated in this section of the application, "GHG emissions from the emergency diesel-fired fire pump engine result from the oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process as there are no post-combustion control technologies identified or available for GHG emissions from small emergency engines. The proposed BACT for GHG emissions from the emergency engines is to follow good combustion practices, the use of ULSD, limiting hours of operation and proper operation and maintenance consistent with NSPS Subpart IIII."

EPD Review – GHG Control

The Division reviewed the RBLC for small (<500 HP) diesel-fired engines in the last five years (since 2018). Engines that were used for purposes other than fire pump engine were removed from the list. The resulting combustion turbines are summarized in Table 4-15. These results show that using engines certified to meet 40 CFR 60 Subpart IIII is the most common control for GHG.

Table 4-15: Summary of BACT Determinations for GHG (CO_2e); Small (<500 HP) Diesel-Fired Engines used as Fire Pump Engines (2018 to present)

RBLC ID	Permit Issuance Date	Engine Size	Limit(s)	Controls
IL-0130	12/31/2018	420 hp	241 tons/yr	
IL-0133	07/29/2022	320 hp	92 tons/yr	
LA-0370	04/27/2020	1.1 MMBtu/hr	9 tons/yr	Good combustion practices in order to comply with 40 CFR 60 Subpart IIII
MI-0433	06/29/2018	300 hp	85.6 tons/yr	Good combustion practices
MI-0435	07/16/2018	399 hp	86 tons/yr	Energy efficient design
MI-0445	11/26/2019	1.66 MMBtu/hr	13.58 tons/yr	Good combustion practices
MI-0451	06/23/2022	300 hp	85.6 tons/yr	Good combustion practices
MI-0452	06/23/2022	300 hp	85.6 tons/yr	Good combustion practices
OH-0376	02/09/2018	250 hp	163.6 lb/MMBtu	Equipment design and maintenance requirements
OH-0377	04/19/2018	320 hp	18.67 tons/yr	Efficient design and proper maintenance and operation
OH-0378	12/21/2018	402 hp	23 tons/yr	Good operating practices (proper maintenance and operation)
OH-0387	09/20/2022	275 hp	162.7 lb/MMBtu	Good combustion practices and proper maintenance and operation

Conclusion – GHG Control

BACT for GHG from the fire pump engine is to follow good combustion practices, to use ultra-low sulfur diesel fuel, to limit the operating time to 500 hours per twelve-consecutive months, and proper operation and maintenance of the engine consistent with 40 CFR 60 Subpart IIII. The BACT selection for the fire pump engine is summarized below in Table 4-16.

Table 4-16: BACT Summary for the Fire Pump Engine

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Purchase of Certified Engine, Good Combustion Practices, and Hours of Operation Limit	4.0 g/kW-hr (3.0 g/hp-hr) NMHC+NOx	N/A	Purchase Subpart IIII Certified Engine
$PM/PM_{10}/PM_{2.5}$	Purchase of Certified Engine, Good Combustion Practices, and Hours of Operation Limit	0.20 g/kW-hr (0.15 g/hp-hr)	N/A	Purchase Subpart IIII Certified Engine
CO	Purchase of Certified Engine, Good Combustion Practices, and Hours of Operation Limit	3.5 g/kW-hr (2.6 g/hp-hr)	N/A	Purchase Subpart IIII Certified Engine
VOC	Purchase of Certified Engine, Good Combustion Practices, and Hours of Operation Limit	4.0 g/kW-hr (3.0 g/hp-hr) NMHC+NOx	N/A	Purchase Subpart IIII Certified Engine
GHG	Good Combustion Practices, Use ULSD, and Hours of Operation Limit	N/A	N/A	Purchase Subpart IIII Certified Engine

Fuel Oil Storage Tanks ST2 and ST3 – Background

The Fuel Oil Storage Tanks (Source Codes ST2 and ST3) will be new vertical fixed roof tanks that will store distillate fuel oil and have a capacity of 1.58 million gallons. The storage tanks will support the modified turbines when they are fired on fuel oil.

Fuel Oil Storage Tanks ST2 and ST3 – VOC Emissions

Applicant's Proposal

Talbot Energy Facility included their analysis for VOC BACT from the fuel oil storage tanks in Section 5.11 of Application 767450. The estimated VOC emissions from the tanks are not expected to exceed 0.94 tpy. This low expected emission level of VOC and the low vapor pressure of distillate fuel oil make any vapor collection and control systems impractical.

Talbot Energy Facility is proposing design and work practice standards as BACT for VOC from the fuel oil storage tanks. Talbot Energy Facility is proposing the use of good operating and maintenance practices in accordance with manufacturer specifications, use of a submerged fill pipe for product loading, and selection of tank roof and shell paint colors which have low solar absorptance as BACT.

EPD Review – VOC Control

The Division reviewed the RBLC for petroleum liquid storage in fixed roof tanks in the last five years (since 2018). Tanks that did not obviously store diesel fuel or distillate fuel oil were removed from the list. The resulting combustion turbines are summarized in Table 4-17. These results show that using a submerged fill pipe, using paint colors with low solar absorptance, and using good operating and maintenance practices are the most common controls for VOC.

Table 4-17: Summary of BACT Determinations for VOC; Petroleum Liquid Storage in Fixed-Roof Tanks; Diesel fuel (2018 to present)

RBLC ID	Permit Issuance Date	Tank Capacity	Tank Contents	Limit	Controls
AK-0085	08/13/2020	19,500 gallons	ULSD	0.59 tons/yr	Submerged Fill
AK-0088	07/07/2022	3,520 gallons	Diesel	0.01 tons/yr	Submerged Fill
IN-0318	06/11/2019		Diesel	2.29 tons/yr	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
IN-0318	06/11/2019		Diesel	0.0114 tons/yr	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
KY-0116	07/25/2022	2000 gallons	Diesel		Spill & overfill protection, Submerged fill pipes, & Good Work Practices (GWP) Plan
OK-0177	01/04/2018	4000 gallons			Submerged fill and good housekeeping, including quarterly inspection requirements in the SPCC plan.
PA-0326	02/18/2021	18,000 gallons	Diesel		Tank vents controlled by carbon canisters designed to reduce VOC emissions by a minimum 95%
TX-0855	03/13/2019	25,000 gallons	Diesel		Painted white and equipped with the submerged fill piping.
TX-0930	10/19/2021				Tanks must be painted white or unpainted aluminum, utilize submerged fill, and designed to be drain-dry.
TX-0936	03/29/2022				Vertical fixed roof tanks storing low vapor pressure products (vp < 0.5 psia) with submerged fill, painted white.
WI-0284	04/24/2018	14,400 gallons	Diesel		Submerged Fill Pipe
WI-0300	09/01/2020		Diesel		

Conclusion – VOC Control

BACT for VOC from the fuel oil storage tanks is to use good operating and maintenance practices, to use a submerged fill pipe for loading product into the storage tanks, and to use tank roof and shell paint colors which have low solar absorptance. The BACT selection for the fuel oil storage tanks is summarized below in Table 4-18.

Table 4-18: BACT Summary for the Fuel Oil Storage Tanks ST2 and ST3

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Good Operating and Maintenance Practices, Submerged Fill Pipe, Paint Colors with Low Solar Absorptance	N/A	N/A	Design, Operating, and Maintenance Records

5.0 TESTING AND MONITORING REQUIREMENTS

Testing Requirements:

Performance tests on the modified turbines will be required for the PSD limits for NOx, PM, CO, and VOC for both natural gas and fuel oil combustion. The CO and VOC testing is required at two loads (base and 70%). The NOx test is conducted in accordance with 40 CFR 60.4400 (40 CFR 60 Subpart KKKK). Periodic tests (every five years) will be required for the PSD limits.

Subpart KKKK requires SO_2 testing for the turbines using fuel monitoring and the procedures in 40 CFR 60.415. These requirements are incorporated in the record keeping and reporting section of the permit.

Monitoring Requirements:

The existing permit already contains most of the necessary requirements for this modification. The existing permit requires NOx and CO CEMS, hours of operation records, and fuel usage records for the turbines. These conditions are being modified to add fuel oil hours and usage for the modified turbines. The existing permit also contains monitor check requirements and minimum data requirements for the CEMS and calculation procedures that do not require changes.

The only new monitoring requirement is for a non-resettable hours meter on the new fire pump engine.

CAM Applicability:

The only control device that will be used to achieve an emission limit in this permit is water injection to control NOx during fuel oil combustion. A CEMS will be used as a continuous compliance determination method for NOx. Because 40 CFR 64.2(b)(1)(vi) exempts limits with a continuous compliance determination method, CAM is not applicable and is not being triggered by the proposed modification. Therefore, no CAM provisions are being incorporated into the facility’s permit.

6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exists for NO_2, CO, $PM_{2.5}$,, PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, and PM_{10}.

The proposed project at the Talbot Energy Facility triggers PSD review for PM/PM_{10}/$PM_{2.5}$, NOx, CO, VOC, and GHG. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for PM_{10}, $PM_{2.5}$, CO, and NO_2. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

Modeling Requirements

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*.

The proposed project will cause net emission increases of PM/PM_{10}/$PM_{2.5}$, NOx, CO, and VOC that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. TRS and VOC do not have established PSD modeling significance levels (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm). While TRS does not have established Significant Impact Levels, it does have an ambient monitoring *de minimis* threshold that is concentration-based. Therefore, TRS modeling was conducted to demonstrate that the project impact is below the ambient monitoring *de minimis* concentration. Modeling is not required for VOC emissions; however, the project will likely have no impact on ozone attainment in the area based on data from the monitored levels of ozone in Muscogee County and the level of emissions increases that will result from the proposed project. The southeast is generally NO_X limited with respect to ground level ozone formation.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the PM_{10}, $PM_{2.5}$, CO, and NO_2 emissions increases at the Talbot Energy Facility would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the SIL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for PM_{10}, $PM_{2.5}$, CO, and NO_2.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses.

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m^3)	PSD Monitoring de minimis Concentration (ug/m^3)
PM_{10}	Annual	1	--
	24-Hour	5	10
$PM_{2.5}$	Annual	0.2	--
	24-Hour	1.2	--
NO_2	Annual	1	14
	1-Hour	7.5	--
CO	8-Hour	500	575
	1-Hour	2000	--

NAAQS Analysis

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 primary and secondary NAAQS are listed in Table 6-2 below.

Table 6-2: Summary of National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
PM_{10}	24-Hour	150 / 150	--
$PM_{2.5}$	Annual	12 / 15	--
	24-Hour	35 / 35	--
NO_2	Annual	100 / 100	0.053 / 0.053
	1-Hour	188 / None	0.10 / None
CO	8-Hour	10,000 / None	9 / None
	1-Hour	40,000 / None	35 / None

If the maximum pollutant impact calculated in the Significance Analysis exceeds the SIL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at the Talbot Energy Facility, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

PSD Increment Analysis

The PSD Increments were established to "prevent deterioration" of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a "reduced" ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions "consume" more that the available PSD Increment).

U.S. EPA has established PSD Increments for NO_X, SO_2, PM_{10}, and $PM_{2.5}$; no increments have been established for CO. The PSD Increments are further broken into Class I, II, and III Increments. The Talbot Energy Facility is located in a Class II area. The PSD Increments are listed in Table 6-3.

Table 6-3: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
PM_{10}	Annual	4	17
	24-Hour	8	30
$PM_{2.5}$	Annual	1	9
	24-Hour	2	4
NO_2	Annual	2.5	25

To demonstrate compliance with the PSD Increments, the increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the facility and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class II increment for any pollutant greater than the SIL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NO_X is February 8, 1988, and the major source baseline for SO_2 and PM_{10} is January 5, 1976. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for PM_{10} and SO_2 as January 30, 1980, and for NO_2 as April 12, 1991.

Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C of this Preliminary Determination and in Volume II, Section 5.0 of the permit application.

Modeling Results

Table 6-4 show that the proposed project will not cause ambient impacts of CO, PM_{10}, and $PM_{2.5}$ above the appropriate SIL. Because the emission increases from the proposed project result in ambient impacts less than the SIL, no further PSD analyses were conducted for these pollutants. However, ambient impacts above the SILs were predicted for NO_2 for the 1-hour averaging periods, requiring NAAQS and Increment analyses be performed for NO_2.

Table 6-4: Class II Significance Analysis Results – Comparison to SILs

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	SIL (ug/m^3)	Significant?
NO_2	1-Hour	716.746	3,607.990	**53.45**	7.5	**Yes**
	Annual	716.991	3,608.001	0.14	1	No
PM_{10}	24-hour	716.991	3,608.001	0.19	5	No
	Annual	716.991	3,608.001	0.03	1	No
$PM_{2.5}$	24-hour	716.991	3,608.001	0.36	25	No
	Annual	716.991	3,608.001	0.035	5	No
CO	1-hour	716.746	3,607.990	213.7	2000	No
	8-hour	716.746	3,607.990	43.54	500	No

Data for worst year provided only.

As indicated in the tables above, maximum modeled impacts were below the corresponding SILs for PM_{10}, $PM_{2.5}$, and CO. However, maximum modeled impacts were above the SILs for NO_2. Therefore, a Full Impact Analysis was conducted for NO_2.

Significant Impact Area

For any off-site pollutant impact calculated in the Significance Analysis that exceeds the SIL, a Significant Impact Area (SIA) must be determined. The SIA encompasses a circle centered on the facility being modeled with a radius extending out to the lesser of either: 1) the farthest location where the emissions increase of a pollutant from the proposed project causes a significant ambient impact, or 2) a distance of 50 kilometers. All sources of the pollutants in question within the SIA plus an additional 50 kilometers are assumed to potentially contribute to ground-level concentrations and must be evaluated for possible inclusion in the NAAQS and Increment Analysis.

Based on the results of the Significance Analysis, the distance between the facility and the furthest receptor from the facility that showed a modeled concentration exceeding the corresponding SIL was determined to be less than 50 kilometers for NO_2. To be conservative, regional source inventories for both of these pollutants were prepared for sources located within 50 kilometers of the facility.

NAAQS and Increment Modeling

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the facility's SIA are ideally included in this regional inventory. Talbot Energy Facility requested and received an inventory of NAAQS and PSD Increment sources from Georgia EPD. Talbot Energy Facility reviewed the data received and calculated the distance from the plant to each facility in the inventory. All sources more than 50 km outside the SIA were excluded. Talbot Energy Facility also received data for sources located in Alabama from the Alabama Department of Environmental Management.

The distance from the facility of each source listed in the regional inventories was calculated, and all sources located more than 50 kilometers from the facility were excluded from the analysis. Additionally, pursuant to the "20D Rule," facilities outside the SIA were also excluded from the inventory if the entire facility's emissions (expressed in tons per year) were less than 20 times the distance (expressed in kilometers) from the facility to the edge of the SIA. In applying the 20D Rule, facilities in close proximity to each other (within approximately 5 kilometers of each other) were considered as one source. Then, any Increment consumers from the provided inventory were added to the permit application forms or other readily available permitting information.

The regional source inventory used in the analysis is included in the permit application and the attached modeling report.

NAAQS Analysis

In the NAAQS analysis, impacts within the facility's SIA due to the potential emissions from all sources at the facility and those sources included in the regional inventory were calculated. Since the modeled ambient air concentrations only reflect impacts from industrial sources, a "background" concentration was added to the modeled concentrations prior to assessing compliance with the NAAQS.

The results of the NAAQS analysis are shown in Table 6-5. For the short-term averaging periods, the impacts are the highest second-high impacts. For the annual averaging period, the impacts are the highest impact. When the total impact at all significant receptors within the SIA are below the corresponding NAAQS, compliance is demonstrated.

Table 6-5: NAAQS Analysis Results

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Background (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
NO_2	1-hour	704.841	3,604.751	999.27	30.3	1,029.57	188	**Yes**

Data for worst year provided only.

As indicated in Table 6-5 above, the total modeled impact for the 1-hour averaging period for NO_2 exceeds the corresponding NAAQS. All of the other total modeled impacts at all significant receptors within the SIA are below the corresponding NAAQS.

NAAQS Contribution Analysis

As shown in Table 6-6, Talbot Energy Facility will not cause or contribute to any violations of the 1-hr NO_2 NAAQS. The number of receptors exceeded the 1-hour NO2 NAAQS level (188 µg/m3) was 3,484 receptors in the culpability analysis modeling output including the background concentration of 30.3 µg/m3. The exceedance(s) at each of NAAQS violation receptors occurred from 1st rank up to 39th, but no exceedances afterward. This refined modeling demonstrates that Talbot Energy Facility will not cause or contribute a significant impact (i.e., ≥ 7.5 µg/m^3) of the NO_2 NAAQS exceedances at the 1-hour averaging period.

Table 6-6: NAAQS Contribution Analysis; 1-hour NO_2

All Sources Modeled Conc. (µg/m^3)	Facility Modeled Conc. (µg/m^3)	UTM East (km)	UTM North (km)	Rank	Remark
1,240.50	0.0041	704.091	3,603.001	1st	Highest 1-hour NO_2 concentration among all receptors exceeding the 1-hour NO_2 NAAQS level
189.64	4.95	704.341	3,610.501	74th	Maximum 1-hour NO_2 Contribution by Talbot among all receptors and ranks exceeding the 1-hour NO_2 NAAQS level

Increment Analysis

The modeled impacts from the NAAQS run were evaluated to determine whether compliance with the Increment was demonstrated. The results are presented in Table 6-7.

Table 6-7: Increment Analysis Results

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
NO_2	Annual	716.991	3,608.001	0.14	2.5	No
PM_{10}	24-hour	716.991	3,608.001	0.19	30	No
	Annual	716.991	3,608.001	0.03	17	No
$PM_{2.5}$	24-hour	716.991	3,608.001	0.24	9	No
	Annual	716.991	3,608.001	0.03	4	No

Data for worst year provided only

Table 6-7 demonstrates that the impacts are below the corresponding increments for PM_{10}, $PM_{2.5}$, and NO_2 even with the conservative modeling assumption that all NAAQS sources were Increment sources.

Ambient Monitoring Requirements

Table 6-8: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
NO_2	Annual	716.991	3,608.001	14	0.14	No
PM_{10}	24-hour	716.991	3,608.001	10	0.19	No
CO	8-hour	716.746	3,607.990	575	43.54	No

Data for worst year provided only

The impacts for NO_X, CO, SO_2, and PM_{10} quantified in Table 6-4 of the Class I Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 6-1, to determine if ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding de minimis concentrations, no pre-construction monitoring is required for NO_2, PM_{10}, SO_2, or CO.

As noted previously, the VOC *de minimis* concentration is mass-based (100 tpy) rather than ambient concentration-based (ppm or $\mu g/m^3$). Projected VOC emissions increases resulting from the proposed modification are less than 100 tpy. Additionally, the current Georgia EPD ozone monitoring network (which includes monitors in Muscogee County) will provide sufficient ozone data such that no pre-construction or post-construction ozone monitoring is necessary.

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define "near", but more recently, a distance of 200 kilometers has been used for all facilities that do not combust coal.

The nearest Class I Area to the facility, Cohutta Wilderness, is more than 245 kilometers away. The magnitude of the emissions from the proposed project do not warrant a review of impacts at this distance. Therefore, no Class I Increment consumption of Air Quality Related Values (AQRV) analyses were performed.

7.0 ADDITIONAL IMPACT ANALYSES

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

Soils and Vegetation

The effect of the proposed project's CO, NOx, PM_{10}, and $PM_{2.5}$ emissions increases on local soils and vegetation is addressed through comparison of modeled impacts to the secondary NAAQS and other relevant screening criteria that have been developed by the U.S. EPA to provide protection for public welfare, including protection against decreased visibility, damage to animals, crops, vegetation and buildings. (U.S. EPA, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*, EPA 450/2-81-078, 1980)

Two comparisons were used to address potential soil and vegetation impacts. First, the significance results for modeled criteria pollutants that were below the SIL (PM_{10}, $PM_{2.5}$, and CO) and the NAAQS modeling results for NO_2 were assessed against the secondary NAAQS standards, which provide protection for public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. Second, modeled impacts for air toxics impacts were compared against conservative screening levels provided by the EPA specifically to address potential soil and vegetation impacts. (U.S. EPA, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*, EPA 450/2-81-078, 1981) Table 7-1 shows the applicable secondary NAAQS or the EPA screening level.

Table 7-1: Soil and Vegetation Impact Thresholds

Pollutant	Averaging Period	Vegetation Sensitivity Sensitive (µg/m³)	Intermediate (µg/m³)	Resistant (µg/m³)	Secondary NAAQS (µg/m³)
NO_2	4-Hour	3,760	9,400	16,920	N/A
	8-Hour	3,760	7,520	15,040	N/A
	1-Month	-	564	-	N/A
	Annual	-	94	-	100
CO	1-week	1,800,000	-	18,000,000	N/A
PM_{10}	24-hour	-	-	-	150
$PM_{2.5}$	24-hour	-	-	-	35
	Annual	-	-	-	15

Table 7-2 shows the impacts for each pollutant and compares the impact to the minimum thresholds from Table 7-1. As seen in these tables, there are no adverse impacts expected on soils or vegetation as a result of the proposed project.

Table 7-2: Results of Soil and Vegetation Impact Analysis

Pollutant	Averaging Period	Total Concentration (µg/m^3)	Minimum Threshold (µg/m^3)	Threshold Exceeded?
NO_2	4-Hour	1570.7	3,760	No
	8-Hour	1413.7	3,760	No
	1-Month	314.1	564	No
	Annual	0.15	94	No
CO	1-week	43.5	1,800,000	No
PM_{10}	24-hour	0.37	150	No
$PM_{2.5}$	24-hour	0.24	35	No
	Annual	0.03	15	No

Growth

As stated in Application 767450, Volume II, Section 3.7, "Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. The proposed project will not result in a change of the current resources necessary to operate and support the project. Therefore, additional economic growth impacts from the proposed project will be minimal."

Visibility

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles, usually in the form of volatile organics, nitrogen oxides, or sulfur oxides, absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light in the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray, or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from continued operation of the mill, the VISCREEN model was used to assess potential impacts on ambient visibility at so-called "sensitive receptors" within the SIA of the Talbot Energy Facility. The only sensitive receptor within the SIA is Columbus Airport (CSG) which 15 miles from Talbot Energy Facility. Since there is no ambient visibility protection standard for Class II areas, this analysis is presented for informational purposes only and predicted impacts in excess of screening criteria are not considered "adverse impacts" nor cause further refined analyses to be conducted.

The primary variables that affect whether a plume is visible or not at a certain location are (1) quantity of emissions, (2) types of emissions, (3) relative location of source and observer, and (4) the background visibility range. For this exhaust plume visibility analysis, a Level-1 visibility analysis was performed using the latest version of the EPA VISCREEN model according to the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015). The VISCREEN model is designed specifically to determine whether a plume from a facility may be visible from a given vantage point. VISCREEN performs visibility calculations for two assumed plume- viewing backgrounds (horizon sky and a dark terrain object). The model assumes that the terrain object is perfectly black and located adjacent to the plume on the side of the centerline opposite the observer.

In the visibility analysis, the total project NO_X and PM_{10} emissions increases were modeled using the VISCREEN plume visibility model to determine the impacts. For both views inside and outside the Class II area, calculations are performed by the model for the two assumed plume-viewing backgrounds. The VISCREEN model output shows separate tables for inside and outside the Class II area. Each table contains several variables: theta, azi, distance, alpha, critical and actual plume delta E, and critical and actual plume contrast. These variables are defined as:

1. *Theta* – Scattering angle (the angle between direction solar radiation and the line of sight). If the observer is looking directly at the sun, theta equals zero degrees. If the observer is looking away from the sun, theta equals 180 degrees.

2. *Azi* – The azimuthal angle between the line connecting the observer and the line of sight.

3. *Alpha* – The vertical angle between the line of sight and the plume centerline.

4. *delta E* – Used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background. A delta E of less than 2.0 signifies that the plume is not perceptible.

5. *Contrast* – The contrast at a given wavelength of two colored objects such as plume/sky or plume/terrain.

The analysis is generally considered satisfactory if *delta E* and *Contrast* are less than critical values of 2.0 and 0.05, respectively, both of which are Class I, not Class II, area thresholds. The Division has reviewed the VISCREEN results presented in the permit application and have determined that the visual impact criteria (*delta E* and *Contrast*) at the affected sensitive receptors are not exceeded as a result of the proposed project. Since the project passes the Level-1 analysis for a Class I area for the Class II area of interest, no further analysis of exhaust plume visibility is required as part of this air quality analysis.

Table 7-3: Level 2 VSICREEN Results: Columbus Airport

Background	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit*	Plume	Crit*	Plume
SKY	10	116	26	53	2.09	0.722	0.05	0.001
	140	116	26	53	2.0	0.216	0.05	-0.004
TERRAIN	10	84	23	84	2.3	0.244	0.05	0.003
	140	84	23	84	2.00	0.057	0.05	0.002

Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*" (Toxics Guideline).

Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the natural gas and fuel oil fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

Talbot Energy Facility calculated the emissions of each TAP in Application 767450, Volume I, Appendix C using published emission factors and maximum expected operating time for each emission unit at the facility. If the annual emission of any TAP is greater than a minimum emission rate (MER) in the Division's Toxics Guideline, modeling for that TAP is required. Talbot Energy Facility included a toxic impact assessment (TIA) in Application 767450, Volume II, Section 5.6.

For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. Talbot Energy Facility referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

Determination of Toxic Air Pollutant Impact

The Georgia EPD *Guideline* recommends a tiered approach to model TAP impacts, beginning with screening analyses using SCREEN3, followed by refined modeling, if necessary, with ISCST3 or ISCLT3. For the refined modeling completed, the infrastructure setup for the SIA analyses was relied upon with appropriate sources added for the TAP modeling. Note that per the Georgia EPD's *Guideline*, downwash was not considered in the TAP assessment.

<u>Initial Screening Analysis Technique</u>

Generally, an initial screening analysis is performed in which the total TAP emission rate is modeled from the stack with the lowest effective release height to obtain the maximum ground level concentration (MGLC). Note the MGLC could occur within the facility boundary for this evaluation method. The individual MGLC is obtained and compared to the smallest AAC. Due to the likelihood that this screening would result in the need for further analysis for most TAP, the analyses were initiated with the secondary screening technique.

The Division repeated the TIA conducted by Talbot Energy Facility. The facility passed the TIA for all pollutants. The results of the TIA conducted by the Division are summarized in Table 7-4.

Table 7-4: Toxic Impact Assessment Results

TAP	Averaging Period	AAC ($\mu g/m^3$)	MGLC ($\mu g/m^3$)	Result
1,3-Butadiene	15-minutes	1,100	0.226	Pass
	Annual	0.03	0.00219	Pass
Acetaldehyde	15-minutes	4,500	0.0369	Pass
	Annual	4.55	0.000350	Pass
Acrolein	15-minutes	23	0.234	Pass
	Annual	0.02	0.00227	Pass
Arsenic	15-minutes	.2	0.00531	Pass
	Annual	0.000233	0.0000900	Pass
Benzene	15-minutes	1,600	0.120	Pass
	Annual	0.13	0.00244	Pass
Beryllium	15-minutes	0.5	0.000317	Pass
	Annual	0.004	0.0000100	Pass
Cadmium	15-minutes	30	0.0290	Pass
	Annual	0.0556	0.000410	Pass
Chromium	15-minutes	10	0.00148	Pass
	Annual	0.000083	0.0000200	Pass
Formaldehyde	15-minutes	245	1.98	Pass
	Annual	1.1	0.0286	Pass
Lead	3-month	0.15	0.00255	Pass
Manganese	15-minutes	500	0.382	Pass
	Annual	0.05	0.00394	Pass
Nickel	24-hour	0.794	0.0269	Pass
Propylene Oxide	Annual	2.70	0.00023	Pass
Selenium	24-hour	0.48	0.00191	Pass

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-263-0013-V-07-1.

Section 1.0: Facility Description

Existing simple-cycle turbines T1, T2, T3, and T4, which currently combust only natural gas, will be modified to add fuel oil combustion. The total allowed operating time on each turbine will also increase. To support the modified turbines, two new fuel oil storage tanks, with a capacity of 1,580,000 gallons each, will be installed. A 455-horsepower diesel-fired fire pump engine and water tank will provide water for fire suppression in case of emergency. The fire pump engine is limited to 500 hours per year of operating time.

Section 2.0: Requirements Pertaining to the Entire Facility

No conditions in Section 2.0 are being added, deleted or modified as part of this permit action.

Section 3.0: Requirements for Emission Units

Condition 3.3.16 is to replace the requirements of existing Conditions 3.3.4, 3.3.7, and 3.3.9 with new Conditions 3.3.17 through 3.3.25 upon startup of the modified turbines. The limitations in 3.3.4, 3.3.7, and 3.3.9 apply until the turbines are modified.

Condition 3.3.17 establishes that 40 CFR 60 Subparts A and KKKK apply to the modified turbines.

Conditions 3.3.18 through 3.3.20 include the BACT emission limits for the modified turbines. Condition 3.3.18 applies while combusting natural gas, Condition 3.3.19 applies while combusting fuel oil, and Condition 3.3.20 applies at all times including startup and shutdown.

Condition 3.3.21 establishes operating hours for the turbines due to PSD requirements.

Conditions 3.3.22 and 3.3.23 limit the fuels (3.3.22) and fuel sulfur content (3.3.23). These requirements are due to PSD and Subpart KKKK.

Condition 3.3.24 lists the BACT methodologies used for each pollutant subject to PSD.

Condition 3.3.25 includes the Subpart KKKK emission limits that apply to the modified turbines. Because the Subpart KKKK limits do not exclude periods of startup and shutdown, they are not completely subsumed by the BACT limits.

Conditions 3.3.26 and 3.3.27 establish that the new fire pump engine is subject to 40 CFR 60 Subparts A and IIII and 40 CFR 63 Subpart A and ZZZZ.

Condition 3.3.28 includes the emission limits for the new fire pump engine due to BACT and Subpart IIII.

Conditions 3.3.29 through 3.3.31 include the fuel and operating standards from Subpart IIII.

Conditions 3.3.32 and 3.3.33 include limits on the new fire pump engine for BACT. Condition 3.3.32 is an hours of operation limit, and 3.3.33 are the control methodologies.

Condition 3.3.34 list the BACT control methodologies for the new fuel oil storage tanks.

Condition 3.3.35 establishes that construction must commence with 18 months of permit issuance and be continuous due to PSD requirements.

Condition 3.4.1 sets the opacity limit from the new fire pump engine due to Georgia Rule (b).

Section 4.0: Requirements for Testing

Conditions 4.2.1 (natural gas) and 4.2.3 (fuel oil) include the initial test requirements to show compliance with the BACT and Subpart KKKK limits.

Conditions 4.2.2 (natural gas) and 4.2.4 (fuel oil) include periodic test requirements to show compliance with the BACT limits.

Section 5.0: Requirements for Monitoring

Condition 5.2.1 was changed to add the new emission limit conditions for the modified turbines.

Condition 5.2.2 was changed to add the fuel oil consumption records and hours of operation while burning fuel oil records for the modified turbines,

Condition 5.2.9 was added to require a non-resettable hours meter on the new fire pump engine.

Section 6.0: Other Recordkeeping and Reporting Requirements

Condition 6.2.1 was modified to add the Subpart KKKK citation.

Condition 6.2.3 was modified to make it clear that this condition only applies to turbines T5 and T6.

Conditions 6.2.4 and 6.2.5 were changed to include the modified turbines for fuel oil consumption records (6.2.4) and hours while burning fuel oil records (6.2.5).

Condition 6.2.13 includes the fuel oil sulfur recordkeeping requirement for the modified turbines due to Subpart KKKK.

Condition 6.2.14 was added to determine the GHG emissions from the modified turbines to show compliance with the PSD limit.

Condition 6.2.15 includes the records requirements for the new fire pump engine due to Subpart IIII.

Condition 6.2.16 requires that twelve-month total hours of operation for the new fire pump engine are determined each month.

Condition 6.2.17 requires notification to the Division of the startup of each new and modified emission unit.

Section 7.0: Other Specific Requirements

No conditions in Section 7.0 are being added, deleted or modified as part of this permit action

APPENDIX A

Draft Revised Title V Operating Permit Amendment
Talbot Energy Facility
Box Springs (Talbot County), Georgia

APPENDIX B

Talbot Energy Facility PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 767450, dated September 7, 2023
2. Additional Information Package Dated Date additional info received from facility. Add more lines if needed
3. Include any other documents if needed. Otherwise, delete

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review