Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

October 2009

Facility Name: Dahlberg Combustion Turbine Electric Generating Facility (Plant Dahlberg)
City: Nicholson
County: Jackson
AIRS Number: 04-13-15700034
Application Number: 18326
Date Application Received: July 10, 2008

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

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Dahlberg Combustion Turbine Electric Generating Facility (hereafter Plant Dahlberg) for a permit to construct and operate four additional simple-cycle combustion turbines (Source Codes: CT11-CT14) and one fuel oil storage tank. The proposed project will construct and operate four dual-fueled Siemens SGT6-5000F simple-cycle combustion turbines (CTGs) and one fuel oil above-ground fixed-roof storage tank. The proposed project will have a nominal generating capacity of 760 MW and will be dual fueled (pipeline-quality natural gas and ultra low sulfur fuel oil).

The proposed project will result in an increase in emissions from the facility. The sources of these increases in emissions include the four dual-fueled Siemens SGT6-5000F simple-cycle combustion turbines (Source Codes: CT11-CT14) and one fuel oil above-ground fixed-roof storage tank.

The modification of Plant Dahlberg due to this project will result in emissions increases in $PM_{2.5}$, PM/PM_{10}, CO, NOx and VOCs. 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 $PM_{2.5}$, PM_{10}, CO, NOx and VOC emissions increases were above the PSD significant level threshold.

The Dahlberg Combustion Turbine Electric Generating Facility (Plant Dahlberg) is located in Jackson County, which is classified as “attainment” or “unclassifiable” for SO_2, $PM_{2.5}$ and PM_{10}, NOx, CO, and ozone (VOC).

The EPD review of the data submitted by Plant Dahlberg 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 $PM_{2.5}$, PM/PM_{10}, CO, NOx and VOC, 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 or in Class I areas located within 300 km of 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 Plant Dahlberg for the modifications necessary to construct and operate four dual-fueled Siemens SGT6-5000F simple-cycle combustion turbines (Source Codes: CT11-CT14) and one fuel oil above-ground fixed-roof storage tank. 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 July 8, 2008, Plant Dahlberg submitted an application for an air quality permit to construct and operate four dual-fueled Siemens SGT6-5000F simple-cycle combustion turbines (Source Codes: CT11-CT14) and one fuel oil above-ground fixed-roof storage tank. The facility is located at 585 Jarrett Road in Nicholson, Jackson 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}	✓	✓		
SO_2	✓	✓		
VOC	✓	✓		
NOx	✓	✓		
CO	✓	✓		
TRS	n/a			
H_2S	n/a			
Individual HAP	✓			✓
Total HAPs	✓			✓

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
4911-157-0034-V-04-0	January 1, 2009	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	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM_{10}	192.6	15	Yes
$PM_{2.5}$	96.3	10	Yes
VOC	93.3	40	Yes
NOx	1190	40	Yes
CO	707	100	Yes
SO_2	14.1	40	No
TRS	n/a	10	No
Pb	0.066	0.6	No
Fluorides	n/a	3	No
H_2S	n/a	10	No
SAM	2.2	7	No

1. The existing facility (10 simple-cycle CTGs) is not a major source of hazardous air pollutants. In addition, after the modification, the total facility will not be a major source of hazardous air pollutants.
2. VOC emissions include emissions from fuel oil tank.

The net increases were calculated from the future projected actual emissions of the four dual-fueled Siemens SGT6-5000F simple-cycle combustion turbines (Source Codes: CT11-CT14) and one fuel oil above ground fixed roof storage tank. The combustion turbine emissions data are the maximum hourly emissions rates over a range of operating loads and ambient operating conditions and also includes startup and shutdown emissions. 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 B of Application No. 18326).

The applicant relied upon data from vendor information provided by Siemens with the following exceptions; on the Natural Gas Data Sheet, the PM rate for all cases above 60% Combustion Turbine (CT) load should be 9.10 lb/hr. The CO rate for all cases above 60% CT load should be 9 ppm (with lb/hr adjusted accordingly). For the Fuel Oil Data sheet, the PM rate for all cases above 70% CT load should be 69 lb/hr. 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 4 Siemens SGT6-5000F CTGs		Associated Units Increase (tpy)	Total Increase (tpy)
	Past Actual[1]	Future Actual		
PM_{10}	0	192.6	0	192.6
$PM_{2.5}$	0	96.3	0	96.3
VOC	0	93.3	0	93.3
NOX	0	1190	0	1190
CO	0	707	0	707
SO_2	0	14.1	0	14.1
TRS	0	n/a	0	n/a
Pb	0	0.066	0	0.066
Fluorides	0	n/a	0	n/a
H_2S	0	n/a	0	n/a

1. New equipment, so past actuals are zero.
2. The existing facility (10 simple-cycle CTGs) is not a major source of hazardous air pollutants. In addition, after the modification, the total facility will not be a major source of hazardous air pollutants.
3. VOC emissions include emissions from fuel oil tank.

Based on the information presented in Tables 1-3 and 1-4 above, Plant Dahlberg's proposed modification, as specified per Georgia Air Quality Application No. 18326, is classified as a major modification under PSD because the potential emissions of $PM_{2.5}$, PM_{10}, VOC, NOx and CO exceed the respective PSD Significant Emission Rates.

Through its new source review procedure, EPD has evaluated Plant Dahlberg'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. 18326, Plant Dahlberg has proposed to construct and operate four additional simple-cycle combustion turbines (Source Codes: CT11-CT14) and one fuel oil storage tank. The proposed project will have a nominal generating capacity of 760 MW. The facility is currently permitted to operate 10 dual-fueled simple-cycle CTGs. After the expansion, the facility will have a total nominal generating capacity of 1530 MW.

Based on emissions calculations described in Section 3 of Application No. 18326, the proposed project will employ Best Achievable Control Technology (BACT) for PM_{10}, CO, NOx and VOCs to minimize air emissions. According to Georgia State Rules for Air Quality Control in GAQCR 391-3-1.03(8)(c)15.(iii) for Jackson County which is an area contributing to the Ambient Air Level of Ozone in the Metropolitan Atlanta Ozone Non-Attainment Area, the requirements of 391-3-1.03(8)(c)2 shall not apply to this electrical generating unit and best available control technology, as defined by the Federal Act, shall be substituted for the lowest achievable emission rate (LAER).

The primary sources of pollutants associated with the proposed project are the four dual fueled Siemens SGT6-5000F combustion turbine generators (CTGs). For this project, the consultant ENSR conducted an air dispersion analysis only for the CTGs. A brief description of the major components of the project is provided in the following paragraphs.

Gas Turbines

Plant Dahlberg proposes to install four Siemens SGT6-5000F gas turbines (Source Codes: CT11-CT14) in simple-cycle mode. The simple-cycle turbines (Source Codes: CT11-CT14) will be dual fueled by pipeline quality gas and ultra low sulfur diesel, with total annual operation based on 35,360,000 MMBtu/yr (16,000 full load equivalent turbine hours per calendar year). The distillate fuel oil is expected to be utilized up to 8,516,000 MMBtu/yr (4,000 full load equivalent turbine hours per calendar year).

The gas turbine is the main component of a simple-cycle power system. First air is filtered, cooled and compressed in a multiple-stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine combustion chamber. Lean pre-mix dry low-NOx combustors minimize NOx formation during natural gas combustion. During periods of distillate fuel oil operation, a NOx reduction water injection system is utilized to minimize NOx formation. Hot exhaust gases from the combustion chamber are expanded through a multi-stage power turbine that results in energy to drive both the air compressor and electric power generator. This operation applies to the proposed turbines (4 Siemens-SGT6-5000F simple-cycle CTGs) and the existing turbines (10 General Electric –GE 7EA's) at the facility.

Fuel Delivery System

Pipeline quality natural gas will be delivered to the plant boundary at a pressure sufficient for use in the CTGs without additional fuel compression.

The gas will first be sent through a knockout drum for removal of any liquid which may have been carried through from the pipeline. The gas then passes through a filter/separator to remove particulate matter and entrained liquid. The gas flows through the filter/separator's first chamber, the filtration section, which removes particulate matter. The gas then flows through the coalescing filters, where entrained liquid is coalesced on the filter cartridges, drops to the bottom of the chamber and either vaporizes and returns to the main gas stream or drains to the sump below. The gas then passes to the second chamber, the separation section, where any entrained liquid remaining in the stream is further separated by impingement on a net or labyrinth and drains to the bottom sump. Four filter/separators are included; one for each proposed CTG. Hydrocarbon liquids in the sump are removed for off-site disposal. The gas is split into four streams, one for each CTG. Finally the gas is delivered to the CTGs and burned as part of the power generation operation.

The plant will also be capable of operating on the distillate fuel oil. The fuel oil will be provided by tanker trucks and unloaded into an above ground storage tank. When the plant operates on distillate fuel oil, the fuel oil is pumped from the storage tank and filtered prior to entering the CTGs.

The Plant Dahlberg permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at http://www.georgiaair.org.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) 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)1 limits visible emissions from any combustion turbine (Source Codes: CT11-CT14) to forty (40) percent opacity.

Georgia Rule 391-3-1-.02(2)(g), Sulfur Dioxide, applies to all "fuel burning" sources. The "fuel burning" sources for the proposed project are the combustion turbines (Source Codes: CT11-CT14). Rule g(1) applies to each combustion turbine because each has an individual heat input capacity exceeding 250 MMBtu/hr and was constructed after January 1, 1972. Rule g(2) applies to each "fuel burning" source for the proposed project. Sulfur dioxide emissions from each combustion turbine shall not exceed 0.8 lb/MMBtu of heat input derived from liquid fossil fuel in accordance with Rule 391-3-1-.02(2)(g)1. The fuel sulfur content limit for fuels burned in each combustion turbine is 3 percent sulfur by weight in accordance with Rule 391-3-1-.02(2)(g)2, which applies to each piece of equipment rated at 100 MMBtu/hr or greater. The existing permit requires that the facility will only fire distillate fuel oil and natural gas at 0.05% or lower sulfur content in the fuel, thus limiting fuel sulfur content to well below 3% sulfur.

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, including Jackson County. However, the requirements contained in subparagraph 1(iii) of this subsection shall not apply to individual units which are subject to 391-3-.03(8)(c)14 or 391-3-1-.03(8)(c)15. This project is subject to 391-3-1-.03(8)(c)15, and therefore the requirements of Rule (nnn) will not apply to combustion turbines(Source Codes: CT11-CT14).

Georgia Rule 391-3-1-.03(8)(c) contains the Additional Provisions for Electrical Generating Units Located in Areas Contributing to the Ambient Air Level of Ozone in the Metropolitan Atlanta Ozone Non-Attainment Area. The main additional requirements of Georgia Rule 391-3-1-.03(8)(c) are (1) obtain NOx offsets at a 1.1 to 1.0 ratio by the time the source is to commence operation; (2) Application of best available control technology (BACT) for NOx; (3) the applicant must demonstrate that all major stationary sources owned or operated by such person in the state are complying with all applicable requirements of the Clean Air Act, including all applicable requirements of the SIP, and (4) an analysis of alternatives.

The construction and operation of the proposed expansion must comply with Georgia Rule 391-3-1-.03(8)(c), which is referred to as the Alternatives Analysis Rule. This analysis must show that the benefits of the proposed project significantly outweigh the environmental and social costs imposed as a result of its proposed location. The proposed facility must take into account alternative sites, sizes of the project, productions processes, and environmental control techniques. The final analysis must be reviewed and approved by the Division prior to issuance of the permit.

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 Unites 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

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart A – General Provisions

Except as provided in Subparts B and C of 40 CFR Part 60, the provisions of this regulation apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility [40 CFR 60.1(a)]. Since the combustion turbines (Source Codes: CT11-CT14) will be subject to a NSPS (Subpart KKKK), the proposed project will be required to comply with applicable provisions of Subpart A. Any new or revised standard of performance promulgated pursuant to Section 111(b) of the Clean Air Act apply to Plant Dahlberg's applicable equipment and/or processes and any applicable source/equipment for which the construction or modification of is commenced after the date of publication in 40 CFR Part 60 of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that equipment and/or processes [40 CFR 60.1(b)]. The only NSPS standards applicable to the simple-cycle combustion turbines (Source Codes: CT11-CT14) are Subpart A and Subpart KKKK. However, this section of this Preliminary Determination also discusses Subpart Kb (for volatile organic liquid storage vessels).

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) 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

Except as provided in paragraph (b) of 40 CFR 60.110b, this regulation applies to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) (19,813 gallons [gal]) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984[40 CFR 60.110b(a)]. According to § 60.111b, a VOL means any organic liquid that can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere. Volatile organic compounds (VOC) means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions [40 CFR 51.100(s)].

This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 (39,890 gallons) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) (approximately 0.51 pounds per square inch ambient) or with a capacity greater than or equal to 75 m^3 (19,813 gallons) but less than 151 m^3 (39,890 gallons) storing a liquid with a maximum true vapor pressure less than 15.0 kPa [40 CFR 60.110b(b)]. The Fuel Oil Storage Tank that will store ultra low sulfur fuel oil for the combustion turbines (Source Codes: CT11-CT14) meets this exemption.

Subpart KKKK (Simple-Cycle Combustion Turbines (CTGs))

In the past, NOx and SO_2 emissions from a CTG were subject to the limits imposed by Subpart GG of 40 CFR Part 60. However, on July 6, 2006, EPA promulgated Subpart KKKK governing emissions from stationary combustion turbines. The applicability of that rule is similar to that of Subpart GG, except that Subpart KKKK applies to new, modified, and reconstructed stationary gas turbines. Subpart KKKK applies to all such affected facilities that commenced construction after February 18, 2005. Because the simple-cycle units of the proposed project are subject to Subpart KKKK, the applicable NSPS NOx emissions limits for those units are as follows:

Subpart KKKK NOx Limit:	
Firing natural gas	15 ppmv at 15% oxygen (0.43 lb/MWh)
Firing distillate oil	42 ppmv at 15% oxygen (1.3 lb/MWh)

Based on the emission rates presented in Section 3.0 of the application, the proposed project will meet the Subpart KKKK standard. Subpart KKKK also establishes an SO_2 emission standard for combustion turbines equal to 0.90 lb/MWh regardless of size and fuel type. 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 percent, by weight, or 500 ppm by weight. The proposed CTGs will fire natural gas and ultra low sulfur diesel fuel (0.0015% S). These fuel types will meet the Subpart KKKK limit for sulfur content in fuel.

National Emissions Standards For Hazardous Air Pollutants

A major source of HAPs is any stationary source that has the potential to emit 10 tpy or more of a single HAP or 25 tpy of combined HAPs. As shown in Section 3 and Appendix B of the application, potential HAP emissions will be well below the major source thresholds for single and combined HAPs. In addition, the existing facility HAP emissions plus the proposed expansion will not exceed the 10/25 tpy HAPs thresholds. Thus the MACT standard, Subpart YYYY – National Emission Standard for Hazardous Air Pollutants from Stationary Combustion Turbines, is not applicable.

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 the CTGs associated with the proposed project are most likely to occur during 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. The facility has estimated the emissions due to the startup/shutdown operations for the proposed CTGs assuming a conservative 250 startup/shutdown events per CTG per year. The following table summarizes the average startup duration as well as the expected emissions of NOx, CO, and VOC on a lb/event basis. SO_2, PM_{10}, and $PM_{2.5}$ emissions are strictly a function of fuel usage and therefore will be maximized during base load operation when the highest fuel use rates are experienced.

Startup/Shutdown Data			
Average Duration (min)	15		
Startup/shutdown Emissions One CTG – Average Conditions (lb/event)			
	NOx	CO	VOC
Natural Gas	30	530	15
Fuel Oil	80	720	70

From Table 3-6 in Section 3.0 of Application. Estimates from Vendor Supplied Data.

The annual start-up shutdown emissions potential-to-emit (PTE) for the combustion turbines (Source Codes: CT11-CT14) were estimated based on two possible startup/shutdown scenarios. Scenario 1 is 250 starts per year per turbine on natural gas and Scenario 2 is 200 starts per year per turbine on natural gas and 50 starts per year on fuel oil. The worst case scenario is Scenario 2 with total emissions of NOx, CO and VOC of 5.00 tpy, 71.00 tpy and 3.25 tpy respectively.

In consideration of excess emissions due to startup, shutdown or malfunction, GA EPD will set NOx emissions BACT limits on a 30 rolling day basis as 15 ppmvd @15% oxygen and twelve consecutive months of 297 tons NOx from each of the combustion turbines (Source Codes: CT11-CT14).

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 an 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.

This applicability evaluation addresses the four new combustion turbines (Source Codes: CT11-CT14) that employ water injection while firing fuel oil to control NOx emissions. NOx and CO_2 are monitored continuously by the CEMS. While the permit amendment does require continuous monitoring of the emissions, it does not provide for a continuous compliance determination method. Method 7 (or alternatively Method 7E) with the appropriate measurements by Methods 1-4 is the method that is the prescribed method for determining compliance with nitrogen oxide emissions. Thus, the facility is required to submit a CAM plan for the new combustion turbines.

The average NOx shall not exceed 42.0 ppmvd at 15% O_2 for any 3 hour rolling average when firing oil. Based on this analysis, Plant Dahlberg has submitted a CAM Plan that describes the general and performance criteria for 1 performance indicator**,** CEMS NOx Value for the 3-hour average. The CAM Plan conditions will be added in Section 5.2 of the Permit Amendment.

Federal Rule – 40 CFR 68 – Chemical Accident Prevention Provisions

Part 68, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 68) Chemical Accident Prevention Provisions

This regulation establishes the list of regulated substances and thresholds, the petition process for adding or deleting substances to the list of regulated substances, the requirements for owners or operators of stationary sources concerning the prevention of accidental releases, and the State accidental release prevention programs approved under section 112(r). The list of substances, threshold quantities, and accident prevention regulations promulgated under 40 CFR Part 68 do not limit in any way the general duty provisions under section 112(r)(1) [40 CFR 68.1].

An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under §68.115, must comply with the requirements of this part no later than the date on which a regulated substance is first present above a threshold quantity in a process [40 CFR 68.1(a)(3)]. Process means any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances, or combination of these activities. For the purposes of this definition, any group of vessels that are interconnected, or separate vessels that are located such that a regulated substance could be involved in a potential release, shall be considered a single process [40 CFR 68.3].

Facilities subject to the rule must conduct a hazard assessment, compile a 5-year accident history, develop an accident prevention program, develop an emergency response program, and submit risk management information to EPA as specified in the regulation. However, the existing facility is not subject to RMP requirements and does not expect that the proposed project will change this status.

Federal Rule – 40 CFR 70 – Title V Operating Permit

Part 70, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 70) State Operating Permit Programs [Title V]
The regulations in 40 CFR Part 70 provide for the establishment of comprehensive State air quality permitting systems consistent with the requirements of title V of the Clean Air Act (Act) (42 U.S.C. 7401, *et seq.*). These regulations define the minimum elements required by the Clean Air Act for State operating permit programs and the corresponding standards and procedures by which the Administrator will approve, oversee, and withdraw approval of State operating permit programs. Georgia has established such a program. Plant Dahlberg, because it can potentially emit applicable pollutants above the applicable major source thresholds, is subject to 40 CFR Part 70. All sources subject to these regulations must have a permit to operate that assures compliance by the source with all applicable requirements [40 CFR 70.1(b)]. An application to modify this permit to include the proposed facility expansion is in Appendix B of this preliminary determination.

Federal Rules – Acid Rain Program

The Acid Rain regulations apply to the proposed simple-cycle electric generating units because they are fossil-fuel fired, they each have a nameplate capacity greater than 25 MW and they are to supply electricity for sale, whether wholesale or retail.

This applicability requires Plant Dahlberg to:

- Amend the facility's Phase II Acid Rain Permit (ARP) to include the four new combustion turbines (Source Codes: CT11-CT14);
- Demonstrate compliance with the ARP provisions meeting the requirements specified in 40 CFR 75; and
- Hold allowances equivalent to annual SO_2 emissions. (The four new combustion turbines (Source Codes: CT11-CT14) are not subject to the NOx requirements in 40 CFR 76.)

The facility must submit an Acid Rain permit application that includes the date that the units will commence commercial operation and the deadline for monitoring certification (90 days after commencement of commercial operation). Acid Rain permits for new units are due 24 months before the unit commences operation.

A Title IV Acid Rain monitoring plan will be developed as required under 40 CFR 72. The plan will include the installation, proper operation and maintenance of continuous monitoring systems or approved monitoring provisions under 40 CFR 75 for SO_2, CO_2 (as a diluent) and opacity. Depending on the monitoring technology available at the time of installation, the plan will cite the specific operating practices and maintenance programs that will be applied to the instruments. The plan will also cite the specific form of records that will be maintained, their availability for inspection and the length of time that they will be archived. The plan will further cite that the Acid Rain permit and applicable regulations will be reviewed at specific intervals for continued compliance and will site specific mechanisms to be used to keep current on rule applicability.

Federal Rules – Clean Air Interstate Rule (CAIR)

The Clean Air Interstate Rule regulations specified in Federal Rule 40 CFR 96 apply to the proposed simple-cycle electric generating units because they each have a nameplate capacity greater than 25 MW, they are fossil-fuel fired, and they are to supply electricity for sale, whether wholesale or retail.

Part 96, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 96) Subpart AA – Clean Air Interstate Rule [CAIR] NOx Trading Program General Provisions, Subpart BB – CAIR Designated Representative for CAIR NOx Sources, Subpart CC – Permits, Subpart FF – CAIR NOx Allowance Tracking System, Subpart GG – CAIR NOx Allowance Transfers, Subpart HH – Monitoring and Reporting

And:

Part 96, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 96) Subpart AAA – Clean Air Interstate Rule [CAIR] SO_2 Trading Program General Provisions, Subpart BBB – CAIR Designated Representative for CAIR SO_2 Sources, Subpart CCC – Permits, Subpart FFF – CAIR SO_2 Allowance Tracking System, Subpart GGG – CAIR SO_2 Allowance Transfers, Subpart HHH – Monitoring and Reporting

These regulations established the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) NOx and SO_2 Trading Programs, under section 110 of the Clean Air Act, §51.123 and §51.124 of Chapter I, as a means of mitigating interstate transport of fine particulates, NOx and sulfur dioxide. The owner or operator of a unit or a source was to comply with the requirements of these regulations as a matter of federal law only if the State with jurisdiction over the unit and the source incorporated by reference such subparts or otherwise adopts the requirements of such subparts in accordance with §51.123(o)(1) or (2) and §51.124(o)(1) or (2) of Chapter I, the State submitted to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approved such revisions.

On December 23, 2008, the U.S. Court of Appeals for the District of Columbia Circuit reinstated the CAIR rule. The court remanded the case without vacatur of CAIR for EPA to conduct further proceedings consistent with the July 11, 2008 opinion in this case, in which EPA was directed to correct identified flaws with this rule. Therefore, this regulation is applicable to the proposed combustion turbines (Source Codes: CT11-CT14) when they commence operation.

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, PM/PM_{10}, $PM_{2.5}$, CO and VOC.

Combustion Turbines (Source Codes: CT11-CT14) - Background

Southern Power Company (SPC), a subsidiary of Southern Company owns and operates Dahlberg Combustion Turbine Electric Generating Plant (Plant Dahlberg), located near Nicholson in Jackson County, Georgia. The present permitted facility consists of ten simple-cycle combustion turbine generators (Source codes: CT01-CT10) and supporting auxiliary equipment. SPC plans to expand this facility by adding four dual-fueled simple-cycle combustion turbines (Source Codes: CT11-CT14). The key elements of the proposed project include:

- Four dual-fueled Siemens SGT6-5000F simple-cycle combustion turbines
- One fuel oil storage tank

The proposed project will have a nominating generating capacity of 760 MW and will be dual fueled (pipeline-quality natural gas and ultra low sulfur fuel oil).

Combustion Turbines (Source Codes: CT11-CT14) – NOx Emissions

Applicant's Proposal

NOx is primarily formed in combustion processes in two ways: (1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NOx); and (2) the oxidation of nitrogen contained in the fuel (fuel NOx). Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen; therefore, NOx emissions from combustion turbines originate as thermal NOx. The rate of formation of thermal NOx is a function of residence time and free oxygen, and is exponential with peak flame temperature.

"Front end" NOx control techniques are aimed at controlling thermal NOx and/or fuel NOx. The primary front-end combustion controls for gas turbines include water or steam injection and dry low-NOx combustors. The addition of an inert diluent such as water or steam into the high temperature region of the flame controls NOx formation by quenching peak flame temperature. This technique can be operationally very hard on the turbine and combustors due to vibration and flame instability. Recent state-of-the-art advances have resulted in dry low-NOx combustors that limit peak flame temperature and excess oxygen with lean, pre-mix flames that achieve equal or better NOx control without the addition of water or steam. Catalytic combustion is an emerging front-end technology which uses an oxidation catalyst within the combustor to produce a lower temperature flame and hence, low-NOx. Other control methods, known as "back-end" controls, remove NOx from the exhaust gas stream once NOx has been formed.

Step 1: Identify all control technologies

The NOx emissions control technologies for simple cycle combustion turbines include the following:

Selective Catalytic Reduction (SCR)
SCONOx^{TM}
Selective Non-Catalytic Reduction (SNCR) and Non-Selective Catalytic Reduction (NSCR)
Dry Low-NOx (DLN) Combustors
Water or Steam Injection
Other Control Technologies

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a process that involves post combustion removal of NOx from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions (Cho, 1994):

$$4NO + 4NH_3 + O_2 \text{ -> } 4N_2 + 6H_2O \qquad (1)$$

$$6NO + 4NH_3 + O_2 \text{ -> } 5N_2 + 6H_2O \qquad (2)$$

$$2NO_2 + 4NH_3 + O_2 \text{ -> } 3N_2 + 6H_2O \qquad (3)$$

$$6NO_2 + 8NH_3 + O_2 \text{ -> } 7N_2 + 12H_2O \qquad (4)$$

$$NO + NO_2 + 2NH_3 \text{-> } 2N_2 + 3H_2O \qquad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NOx decomposition reaction. SCR using ammonia as a reagent represents the state-of-the-art technology for NOx removal from the exhaust gas from base load, combined-cycle turbines.

Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/binding, reported catalyst failure due to “crumbling”, design of the NH_3 injection system, and high NH_3 slip.

SCONOx^{TM}

SCONOx^{TM} is an emerging post-combustion technology that removes NOx from the exhaust gas stream after formation in the combustion turbine. SCONOx^{TM} employs a potassium carbonate bed that adsorbs NOx where it reacts to form potassium nitrates. Periodically, a hydrogen gas stream is passed over the bed, resulting in the reaction of the potassium nitrates to reform the potassium carbonate and the ejection of nitrogen gas and water.

SCONOx^{TM} is reportedly capable of achieving NOx emission reductions of 90% or more for combustion turbine application, and it is currently operating on several small natural gas-fired turbines. The advantage of SCONOx^{TM} relative to SCR is that SCONOx^{TM} does not require ammonia injection to achieve NOx emissions control.

Selective Non-Catalytic Reduction (SNCR) and Non-Selective Catalytic Reduction (NSCR)

Two other back-end catalytic reduction technologies, Selective Non-Catalytic Reduction (SNCR) and Nonselective Catalytic Reduction (NSCR), have been used to control emissions from certain other combustion process applications.

Dry Low-NOx (DLN) Combustors

DLN combustion control techniques reduce NOx emissions without injection of water or steam (hence "dry"). DLN combustors are designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NOx formation. This is accomplished by producing a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors. DLN combustors are employed for natural gas only; they are not designed for oil combustion. A combustion turbine is equipped with multiple nozzles, and thus the usual burner arrangement for a combustion turbine that will be fired with both natural gas and oil is to equip it with DLN combustors used only for natural gas and conventional combustors (most typically, equipped with water or steam injection) used only for oil firing.

DLN combustors are considered to be technically feasible for combustion turbines, but for natural gas firing only.

Water or Steam Injection

Water and steam injection are also designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NOx formation. This technology involves the injection of water or steam into the high temperature region of the flame, which minimizes thermal NOx formation by quenching peak flame temperature.

Water and steam injection has been employed successfully for nearly thirty years, for both natural gas and oil-fired combustion turbines. Water and steam injection remains the state-of-the-art combustion technology for minimizing NOx emissions for oil-fired combustion turbines.

Water injection is considered to be technically feasible for combustion turbines for natural gas and oil firing operations.

Other Control Technologies

A number of other combustion turbine NOx emissions control technologies for combustion turbines are being marketed. These include Catalytica Energy Systems' XONON™ catalytic combustors, BOC Gases' LoTOx™ ozone injection system, Thermal Energy's THERMALLONOx™ phosphorus injection/scrubber system, and Enviroscrub's Pahlmann™ Process.

Step 2: Elimination of Infeasible Controls

Selective Catalytic Reduction (SCR)

Conventional (low temperature) SCR is not applicable to simple-cycle turbines due to materials temperature limitations that preclude its application in high-temperature simple-cycle turbine exhaust. High temperature SCR (hot SCR) is technically feasible for simple-cycle turbines, but has not been demonstrated in practice for large (F-Class) frame turbines. It has only been "demonstrated" in practice" for aeroderivative turbines and not for the F-Class Frame turbines proposed for this Project. Recently, a large frame simple-cycle turbine in California was permitted to utilize hot SCR to minimize NOx emissions and is currently operating.

SCONOx™

SCONOx™ is not technically feasible for application to this project for several reasons. First, SCONOx™ is not being offered for the Siemens SGT6-5000F or any other type of large combustion turbines. Due to concerns regarding catalyst poisoning, SCONOx™ is not a proven technology for meeting the lowest achievable emission levels for NOx for oil firing in a combustion turbine. The only known commercial application of this technology for a combustion turbine fired with oil is at the Wyeth Bio Pharma facility in Andover, Massachusetts. This system, which is required to meet a NOx emissions limit of 15 ppmvd @ 15% O_2 experienced numerous problems meeting that limit and as a result has not been run on oil for more than several hours at a time. Other significant detriments to SCONOx™ include that it is considerably more complex than SCR, only operates within a specific temperature range, consumes significantly more water, and would require more frequent cleaning and other maintenance.

Selective Non-Catalytic Reduction (SNCR) and Non-Selective Catalytic Reduction (NSCR)

Both of these technologies have limitations that make them inappropriate for application to combustion turbines. SCNR requires a flue gas exit temperature in the range of 1300 to 2100 ^{o}F, with an optimum operating temperature zone between 1600 and 1900 ^{o}F (Fuel Tech. 1991). Simple-cycle combustion turbines have exhaust temperatures of approximately 1100 ^{o}F, and combined-cycle turbines have exhaust temperatures much lower than simple-cycle turbines. Therefore, additional fuel combustion of a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible and inappropriate for the proposed combustion turbines.

NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% O_2 in the exhaust), NSCR is infeasible and inappropriate for the proposed combustion turbines.

Other Control Technologies

None of the "Other Control Technologies", as listed above, have reached the commercial development stage for large combustion turbines that will be fired with natural gas and oil, and thus none are considered to be technically feasible for application to this project.

Step 3: Ranking of Available Control Techniques

The technically feasible control technologies for NOx emission control for simple cycle turbines are SCR, DLN burners and water injection. Although high temperature SCR is technically feasible for simple-cycle turbines, this control technology has been demonstrated in practice only on aeroderivative-type simple-cycle turbines. High temperature SCR has not been commercially demonstrated for simple-cycle turbines in the size range selected for Plant Dahlberg. Even if high temperature SCR was an option capable of reducing NOx emissions to 3 ppm when burning natural gas, this technology would cost between $10,000-$20,000/ton of NOx removed per Siemens SGT6-5000F turbine depending on the hours of oil burned. Consequently, high temperature SCR would not be cost effective on the simple-cycle turbines proposed for the expansion at Plant Dahlberg. Therefore, the combination of DLN combustors and water injection are the demonstrated and technically feasible options to be considered for this project.

Step 4: Most Effective Control

Based on the information in the facility's search of the RACT/BACT/LAER Clearinghouse, shown in Appendix C of the application, the combination of DLN combustors and water injection have been installed on large F-Class Frame simple-cycle combustion turbines to minimize NOx emissions, and therefore are considered to be the most effective controls.

Step 5: Selection of BACT

BACT Control for the proposed combustion turbines operating in simple-cycle mode is the use of DLN burners while firing natural gas and the use of water injection while firing fuel oil. The following BACT NOx emission rates are proposed for the combustion turbines:

- Natural Gas: 9 ppmvd @ 15% O_2
- Fuel Oil: 42 ppmvd @ 15% O_2

EPD Review – NOx Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the NOx BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[1]
- USEPA Region IV and the National Combustion Turbine Simple Cycle Spreadsheets – (Accessed February 2, 2009)[2]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Permit Application for Bridgeport Peaking Station, Connecticut[3]
- Final Determination for EI Colton, LLC, California and South Coast Air Quality Management District staff contact Howard Lange.[4]
- Technical Evaluation and Preliminary Determination for Florida Power Corporation, Progress Energy Florida, P.L. Bartow Power Plant in Pinellas County, Florida[5]
- JEA GEC Combined Cycle Combustion Turbine Conversion, Black and Veatch Evaluation, September 2008, BACT Analysis, Florida[6]
- Revised Technical Evaluation-BACT Analysis and Final Determination for JEA GEC Construction of 2 General Electric (GE) PG7241 FA gas turbine electrical generators (nominal 190 MW each), December 18, 2008 and March 10, 2009[7], Florida
- Permit to Construct Application, Bridgeport Peaking Station, Bridgeport, CT, June 1, 2007[8]
- Florida Power and Light Company-Martin Plant Permit issued on April 16, 2003[9]
- AP 42, Fifth Edition, Volume I, Chapter 3- Stationary Internal Combustion Sources[10]

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[1] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

[2] http://www.epa.gov/region4/air/permits/

[3] http://www.ct.gov/csc/lib/csc/pendingproceeds/petition_841/attachment_f_bulk_exhibit_air_permit_app_june07.pdf

[4] www.aqmd.gov/bact/406065EIColton.doc

[5] Air Permit No. PSD-FL-381 at http://www.dep.state.fl.us/air/emission/apds/default.asp

[6] http://www.dep.state.fl.us/air/emission/construction/grreenland/bact.pdf

[7] Air Permit No. PSD-FL-401 at http://www.dep.state.fl.us/air/emission/apds/default.asp

[8] http://www.ct.gov/csc/lib/csc/pendingproceeds/petition_841/attachment_f_bulk_exhibit_air_permit_app_june07.pdf

[9] Air Permit Nos. PSD-FL-286 and PSD-FL-327 at http://www.dep.state.fl.us/air/emission/apds/default.asp

[10] http://www.epa.gov/ttn/chief/ap42/ch03/index.html

- EPA's MACT data base Version 5, 10/15/02[11]

The same resources have been utilized in preparing the Division's PM_{10}, CO and VOC BACT analyses. The Division has prepared BACT comparison spreadsheets for all pollutants for the similar units using the above-mentioned resources and they are attached in Appendix D.

GA EPD requested that the facility provide additional information that discusses whether a hot selective catalytic reduction (SCR) system like the one recently permitted for control of large frame simple-cycle turbine NOx emissions in California at EI Colton, LLC is feasible for this project. A NOx emission limit of 3.5 ppmvd, corrected to 15 percent oxygen, for natural gas firing was recently determined as BACT. This limit is based on the use of a high temperature SCR system that also utilizes a tempering air system to control the gas temperature entering the catalyst. It should be noted, however, that the SCR catalyst typically requires time to warm up before it will effectively control NOx emissions. In the event that SCR is selected as BACT, alternative BACT limits may be necessary for periods of startup and shutdown.

Three other facilities using SCR for control of NOx, as listed in the BACT comparison spreadsheet attached in Appendix D, proposed the lowest NOx emissions limit between the range of 2.0 to 3.5 ppmvd, corrected to 15 percent oxygen. They are again listed in the table below.

Facility	RBLC ID	Model Type	NOx Emissions	Fuel
Bayport Energy	TX-0453	(2) 40 MW Combined Cycle	3.5 ppmvd @15% O_2 3-hr ave	Natural Gas/Fuel Oil
Competitive Power Ventures, Inc./CPV Maryland, LLC	MD-0040	(2) 176 MW Combined Cycle	2.0 ppmvd @15% O_2 3-hr rolling ave	Natural Gas
JEA Greenland	N/A	(2) 190 MW Combined Cycle	2.0 ppmvd @15% O_2 3-hr ave	Natural Gas/Ultra Low Sulfur Fuel Oil
EI Colton, LLC	CA-1095	(1) 48.7 MW Simple Cycle	3.5 ppmvd@ 15% O_2 3-hr ave (LAER limit)	Natural Gas

The facility has responded with and GA EPD has confirmed the following: "Large frame type simple cycle gas turbines operate with exhaust gas temperatures near or above 1,100 F. The EI Colton, LLC project has constructed a GE LM6000 simple cycle turbine. The exhaust temperature for this 49 MW aeroderivative gas turbine is only 825 F, significantly less than that of the proposed Dahlberg turbines, allowing for the use of hot SCR. The other three facilities, listed in the table above, are all combined cycle facilities that also have lower exhaust temperatures suitable for the use of SCR technology.

Furthermore, the limits applied to the EI Colton project are LAER limits (not BACT limits) and are not an appropriate source of comparison for the Dahlberg units. There have been no BACT determinations requiring SCR on a simple cycle F class turbine." GA EPD further adds that on review of the RBLC database, the EI Colton facility has tested the GE LM6000 simple cycle turbine and the results were below the permit limit for NOx and the facility is currently operating.

GA EPD requested the facility to recalculate the cost analyses, using a six-year catalyst life for the oxidation catalyst technology and a longer catalyst life for the Hot SCR technology. The facility responded that; "the cost analysis presented in the permit application for high temperature SCR showed

[11] http://www.epa.gov/ttn/atw/combust/turbine/testsv5.mdb

that this technology was not cost effective due to costs in the $10,000 to $20 000 per ton range. A revised cost effectiveness calculation based on a six-year catalyst life (as was used in the Greenland project), shows that the cost effectiveness is in the $13,000 to $26,000 per ton range."

GA EPD reviewed the cost effectiveness calculation for the 4000 hours natural gas-fired scenario and verified that at a catalyst life of 3 years, 6 years and 12 years (as submitted in the application), the cost effectiveness would exceed $20,000 per ton. In determining the cost effectiveness for Hot SCR technology, the facility referenced the FPL Martin Project (FL-0024) which had installed 4 similarly sized combined/simple cycle units, and it estimated equipment costs and auxiliaries at 3.5 million dollars.

On March 23, 2009, Pamela Murphy of Peerless was contacted by GA EPD to ascertain the estimate to install Hot SCR systems for large simple cycle turbines, and she responded with an estimate of 10 million dollars. Thus, the cost effectiveness to remove NOx is even higher than what the facility has estimated for installing Hot SCR technology on Large Frame Simple Cycle Turbines.

GA EPD contacted John Yee, Senior Engineer with the South Coast Air Quality Management District (AQMD), California to discuss the EI Colton, LLC project and similar projects with submitted applications. It was discussed that for large, frame type simple cycle gas turbines at exhaust temperatures of 1,100 ^{o}F, the use of a Hot SCR system requires a tempering system to bring the exhaust temperature in the range of 800 ^{o}F to allow a Hot SCR system to work. Also, the SCR technology is LAER for the EI Colton project since it is located in a non-attainment area. Therefore, after this discussion and further review of the RBLC and the EPA Combustion Turbine Simple Cycle Spreadsheet (Region IV), GA EPD agrees that dry-low NOx burners for natural gas-fired operation and water injection for fuel oil-fired operation, represent NOx BACT control for simple cycle combustion turbines.

Conclusion – NOx Control

GA EPD agrees with the proposed BACT control technology of the use of dry-low NOx burners for natural gas-fired operation and water injection for fuel oil-fired operation for NOx control in the combustion turbines. As summarized by the spreadsheet in Appendix D, GA EPD noted a NOx BACT limit in the range between 2.0 ppmvd @ 15% O_2 to 25.0 ppmvd @ 15% O_2 for natural gas, with 9.0 ppmvd @ 15% O_2 appearing at 9 facilities with comparatively sized engines that were subject to BACT. For fuel oil, the average limit is 42 ppmvd @ 15% O_2 at normal operating loads and as high as 96.0 ppmvd @ 15% O_2 at less than 75% load. GA EPD concurs with the proposed BACT limits (9 ppmvd @15% oxygen when firing natural gas and 42 ppmvd @15% oxygen when firing fuel oil) that are based on estimated performance data and emissions guarantees provided by the turbine supplier (Siemens) for the particular turbines to be used for this project.

To account for emissions due to startup, shutdown or malfunction, GA EPD has decided to include NOx emissions BACT limits of 15 ppmvd @15% oxygen (30 days rolling average) while firing natural gas and 297 tons of NOx emissions (12 consecutive month average) firing natural gas or fuel oil from each of the combustion turbines (Source Codes: CT11-CT14).

The BACT selection for the combustion turbines (Source Codes: CT11-CT14) is summarized below in Table 4-1.

Table 4-1: BACT Summary for the Combustion Turbines (Source Codes: CT11-CT14)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Dry Low NOx Burners (firing Natural Gas) Water Injection (firing Fuel Oil)	9 ppmvd @ 15% O_2 42 ppmvd @ 15% O_2	3 hours	NOx CEMS
NOx	Dry Low NOx Burners (firing Natural Gas)	15 ppmvd* @ 15% O_2	30 day rolling average	NOx CEMS
NOx	Dry Low NOx Burners (firing Natural Gas) Water Injection (firing Fuel Oil)	297 tons*	12 consecutive month average	NOx CEMS

*Limit includes emissions during startup and shutdown.

Combustion Turbines (Source Codes: CT11-CT14) – Particulate Matter Less than 10 Microns (PM_{10}) Emissions

Applicant's Proposal

Particulate matter emissions from combustion turbines are a combination of filterable (front-half) and condensable (back-half) particulate. Filterable particulate matter is formed from impurities contained in the fuels and incomplete combustion. Condensable particulate emissions are attributable primarily to the formation of secondary particulate from conversion of sulfates and nitrates in the exhaust stream after it has been vented from the stack into the atmosphere.

Step 1: Identify all control technologies

When the initial New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA recognized that "particulate emissions from stationary gas turbines are minimal," and noted that particulate control devices are not typically installed on gas turbines and that the cost of installing a particulate control device is prohibitive (EPA, September 1977). Performance standards for particulate control of stationary gas turbines were, therefore, not proposed or promulgated.

The most stringent particulate control method demonstrated for gas turbines is the use of low ash and low sulfur fuel. No add-on control technologies are listed in the RACT/BACT/LAER Clearinghouse listings for combustion turbines. Proper combustion control and the firing of fuels with negligible or zero ash content and a low sulfur content for the combustion turbines is the predominant control method listed.

The use of pipeline quality natural gas and ULSD fuel is considered to be technically feasible for application to this project.

Step 2: Elimination of Infeasible Controls

Add-on controls, such as Electrostatic Precipitators (ESPs) or baghouses, have never been applied to commercial gas fired turbines. The use of ESPs and baghouses is considered technically infeasible, and does not represent an available control technology.

Step 3: Ranking of Available Control Techniques

The only available technology for the control of PM_{10} emissions from large combustion turbines fired with both natural gas and oil is the use of fuels with low sulfur contents.

Step 4: Most Effective Control

For natural gas, there are no fuel choices available. Pipeline quality natural gas contains essentially minimal sulfur. For fuel oil combustion, the cleanest available fuel choice is "ultra low sulfur distillate" (ULSD) fuel. This fuel has a maximum sulfur content of 0.0015% by weight. Using this fuel in combination with a restriction on annual usage is the most stringent available control technology option for the project.

Step 5: Selection of BACT

The use of pipeline quality natural gas and ULSD fuel is concluded to represent BACT for PM_{10} control for the proposed simple-cycle turbines. The BACT emissions limits are as follows:

- Natural Gas: 9.1 lb/hr, when firing natural gas (average of 3 one hour tests); and
- Fuel Oil: 69 lb/hr, when firing oil (average of 3 one hour tests).

EPD Review - Conclusion – PM_{10} Control

The Division has prepared a PM_{10} BACT comparison spreadsheet for the similar units using the above-mentioned resources as discussed in the NOx BACT review and it is attached in Appendix D. Based on the research performed by the Division and review of the applicant's proposal, GA EPD agrees that pipeline quality natural gas and ULSD fuel represents BACT control technology for $PM_{10.}$ The permit restricts all fuel usage for natural gas and ultra low sulfur distillate (ULSD) to 3.536 x 10^7 Btu (approximately equivalent to 16,000 hours of operation) during any 12 consecutive months. Also ULSD is limited to 8.516 x 10^6 Btu (approximately equivalent to 4,000 hours of operation) during any twelve consecutive months. A permit obtained on January 1, 2007 by the Bridgeport Peaking Station, as listed in the spreadsheet, also retains ULSD and total fuel limits for two simple cycle combustion units with similar size and type of combustion turbines. The facility was limited to 2,500 annual operating hours for each of the combustion turbines and 400 hours per year ULSD oil firing for each combustion turbine.

GA EPD agrees with the PM_{10} BACT limits of 9.1 lb/hr, when firing natural gas, and 69 lb/hr, when firing fuel oil, based on performance guarantees for the combustion turbines (Source Codes: CT11-CT14), along with good combustion control and are summarized below in Table 4-2.

Table 4-2: BACT Summary for the Combustion Turbines (Source Codes: CT11-CT14)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM_{10}	Good Combustion Practices, Pipeline Quality Natural Gas	9.1 lb/hr	3 hours	Testing
	Good Combustion Practices, Ultra low Sulfur Distillate (USLD) Oil	69 lb/hr	3 hours	Testing
PM_{10}	Operating Limit	3.536 x 10^7 Btu while firing Natural Gas and USLD	12 consecutive month average	Recordkeeping
	Operating Limit	8.516 x 10^6 Btu while firing USLD	12 consecutive month average	Recordkeeping

Combustion Turbines (Source Codes: CT11-CT14) – Particulate Matter Less than 2.5 Microns ($PM_{2.5}$) Emissions

Applicant's Proposal

On May 8, 2008, EPA issued a rule that finalizes several NSR program requirements for sources that emit $PM_{2.5}$ and other pollutants that contribute to $PM_{2.5}$. The rule adopts a significant emission rate of 10 tons per year for direct $PM_{2.5}$ emissions as well as other levels for pollutants that contribute to $PM_{2.5}$ (including SO_2 , NOx, and VOC). However, the new rule contains a transition policy that suggests SIP-approved states should continue to use PM_{10} as a surrogate for $PM_{2.5}$ in attainment areas until the state revises its SIP. Therefore, since Plant Dahlberg is located in an attainment area for $PM_{2.5}$ (Jackson County), the new rule does not apply until Georgia revises its SIP.

$PM_{2.5}$ can be emitted directly from a source or formed secondarily in the atmosphere from emissions of other compounds referred to as precursors. The new rule will eventually address both filterable and condensable direct $PM_{2.5}$ emissions. However, due to uncertainties in existing data for condensable $PM_{2.5,}$ the new $PM_{2.5}$ rule contains a "transition period" during which NSR permits need not address direct condensable $PM_{2.5}$ emissions. The transition period extends until 2011 or until sufficient advances are made in the test methods for measuring $PM_{2.5}$ to enable accurate and reliable measurements. Directly emitted $PM_{2.5}$ is addressed below while other pollutants that may contribute to $PM_{2.5}$ are addressed in other respective sections of this BACT analysis.

Very limited information and data exist concerning the characterization of $PM_{2.5}$ emissions from combustion turbines. A review of EPA AP-42 Emission Factors indicates the following:

- Section 3.1 (Stationary Gas Turbines) contains PM emission factors but does not specify a particle size for these emissions.

- Section 1.4 (Natural Gas Combustion) contains PM emission factors and notes that it is assumed all PM is less than 1.0 micrometer in diameter.

SPC contacted its combustion turbine vendor regarding estimates of $PM_{2.5}$ emissions from the proposed CTGs. This vendor has indicated that specific data, measurements or estimates of $PM_{2.5}$ emissions are not currently available since there is not an approved test method for measuring $PM_{2.5}$. Accordingly, the vendor suggested that the facility assumes all PM_{10} in the manufacturer's estimate is also $PM_{2.5}$. This is not a guaranteed emission value but it is simply an estimate. Using this assumption as an upper bound, primary $PM_{2.5}$ emissions (filterable) would not exceed the level of primary (filterable) PM_{10} emissions.

Based on a review of the RBLC for $PM_{2.5,}$ only one large combustion turbine project is listed. The Cass County Power Plant (RBLC Listing No. NE-0021) in Nebraska lists a $PM_{2.5}$ limit of 0.1200 MMBtu/hr and 15.3 lbs per hour. However, after speaking with the permitting authority, it was confirmed that this listing is in error and is actually a limit for PM_{10} emissions rather than $PM_{2.5}$ emissions. Thus there are no RBLC entries for combustion turbines establishing a permit limit for $PM_{2.5}$ emissions.

Summary of Combustion Turbine ($PM_{2.5}$) BACT

Since there is limited vendor information for $PM_{2.5}$ emissions and since there are no valid listings in the RBLC for $PM_{2.5}$ emissions, the facility has not proposed a $PM_{2.5}$ BACT limit.

EPD Review - Conclusion – $PM_{2.5}$ Control

GA EPD agrees that a separate BACT limit of $PM_{2.5}$ aside from PM_{10} is not proposed at this time for the reasons stated. The facility will be using PM_{10} emissions as a surrogate to estimate $PM_{2.5}$ emissions.

Combustion Turbines (Source Codes: CT11-CT14) – CO Emissions

Applicant's Proposal

Step 1: Identify all control technologies

Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, CO will react with oxygen present in the exhaust stream, converting it to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst.

Oxidation catalysts have been employed successfully for two decades, for both natural gas and oil-fired combustion turbines. Similar to SCR systems, for oxidation catalysts to be successful in oil-fired combustion turbine applications, it is generally best when both the amount and the sulfur content of the oil fired are closely restricted, in this case to minimize the formation of SOx.

An oxidation catalyst is considered to be technically feasible for application to this project.

Good Combustion Controls

CO emissions are formed in combustion turbines as a result of incomplete combustion of carbonaceous fuels. Similar to generation of NOx emissions, the primary factors influencing the generation of CO emissions are temperature and residence time within the combustion zone. Variations in fuel carbon content have relatively little effect on overall CO emissions. Generally the effect of the combustion zone temperature and residence time on CO emissions generation is the exact opposite of their effect on NOx emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions, but higher NOx emissions. So, the key to the best design lies in the ability to use all the oxygen available with input air for combustion, while controlling the temperature such that NO_x formation can be minimized.

Please refer to the article, "Advanced SGT6-5000F Development presented at Power-Gen International 2008 - Orlando, Florida" available at http://www.powergeneration.siemens.com/news-events/technical-papers/gas-turbines-power-plants/#AdvancedSGT6-5000FDevelopment for available good combustion practices for the SGT6-5000F Combustion Turbine, which is the turbine type that Plant Dahlberg will construct/install with this project.

Good combustion controls are technically feasible for this project.

Step 2: Elimination of Infeasible Controls

Appendix C of the application contains the complete economic analysis which shows that the cost effectiveness of oxidation catalyst ranges from $15,000/ton of CO removed to over $20,000/ton, depending on the hours of distillate fuel burned. Therefore, the utilization of a high temperature oxidation catalyst would not be cost effective for the proposed simple cycle turbine due to the limited number of operating hours per year.

Based on the results of the economic analysis, the installation of an oxidation catalyst for additional control of CO emissions is not cost-effective and therefore is not considered BACT control. The use of an oxidation catalyst would also reduce the electricity generation potential from the turbines, increase energy consumption at the facility and result in collateral increases in emissions of PM_{10} and sulfuric acid mist emissions. Consequently, an oxidation catalyst system will not be installed on the proposed combustion turbines.

Step 3: Ranking of Available Control Techniques

The available control techniques, are Oxidation Catalyst Technology and Good Combustion Controls.

As with SCR catalyst technology for NOx control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to proceed. Rather, the oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust; and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10} and sulfuric acid mist emissions. When operating at 1100 ^{o}F, almost 100% of the SO_2 emissions will be oxidized to sulfuric acid mist. Any benefits associated with reduced CO emissions will be more than offset by increased PM_{10} and sulfuric acid mist emissions.

As with SCR, CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700 ^{o}F to 1,100 ^{o}F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1200 ^{o}F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, CO catalyst is strategically placed within the proper turbine exhaust lateral distribution (it is important to evenly distribute gas flow across the catalyst) and proper operating temperature at base load design conditions. Operation at part load, or during startup/shutdown will result in less than optimum temperatures and reduced control efficiency.

Typical pressure losses across an oxidation catalyst reactor (including pressure loss due to ammonium salt formation) are in the range of 0.7 to 1.0 inches of water. Pressure drops in this range correspond roughly to a 0.15 percent loss in power output and fuel efficiency or approximately 0.1 percent loss in power output for each 1.0 inch of water pressure loss.

Catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5 to 6 year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation. Since the proposed combustion turbines can fire either natural gas or fuel oil, catalyst replacement will likely be required every 3 years.

Oxidation catalyst systems are ranked as the highest option for minimizing CO emissions, followed by good combustion controls.

Step 4: Most Effective Control

An oxidation catalyst is a technically feasible control technology and most effective control technology for minimizing CO emissions from simple-cycle turbines firing natural gas or fuel oil. Oxidation catalysts are capable of reducing potential uncontrolled CO emissions by approximately 80% annually.

Step 5: Selection of BACT

Oxidation catalyst systems would not be cost effective for the proposed simple cycle combustion turbines. Therefore, the use of good combustion control is concluded to represent BACT for CO control for the proposed combustion turbines. The following BACT CO emission rates are proposed for the combustion turbines:

- 9 ppmvd @ 15% O_2, when firing natural gas (average of 3 one hour tests); and
- 30 ppmvd @ 15% O_2, when firing fuel oil (average of 3 one hour tests).

<u>EPD Review – CO Control</u>

The Division has prepared a CO BACT comparison spreadsheet for the similar units using the above-mentioned resources, as discussed in the NOx BACT review, and it is attached in Appendix D.

Fred Booth of Engelhard was contacted on March 6, 2009, to discuss the effectiveness of Catalyst Oxidation on simple cycle natural gas fired and fuel oil fired combustion turbines. Although the Siemens SGT6-5000F frame has not previously employed this technology, approximately 300 comparable though smaller frame installations on simple cycle turbines that operate as peaking units, have this technology installed.

The CO BACT limits proposed in the application (9 ppm when firing natural gas / 30 ppm when firing fuel oil) are based on the estimated performance data and emissions guarantees provided by the turbine supplier (Siemens) for the particular turbines to be used for this project. These values represent guarantees across the intended operating ranges for these turbines (60% to 100% load when firing natural gas and 70% - 100% load when firing fuel oil). Southern Power has not included any margin above these guarantees in the proposed BACT limits.

GA EPD initially proposed CO BACT limits such as the values proposed for the currently constructed JEA Greenland project by FDEP (4.1 ppm / 8.0 ppm) although these values have not been achieved in practice. The facility responded and GA EPD confirmed the following: "The JEA Greenland project intends to use turbines from an entirely different manufacturer (GE). FDEP, in its Revised Technical Evaluation and Preliminary Determination (JEA Determination) for the Greenland project (JEA Determination page 22) acknowledges that GE is offering guarantees of 5 ppm when firing natural gas under certain circumstances. FDEP also uses a limited amount of test data from several "new and clean" GE turbines to support its position that the turbines should be able to meet the proposed limits (JEA Determination page 21).

Regarding the Progress energy Bartow Unit 5 project, it should be noted that its permit limits have also not been achieved in practice. In setting its limits, FDEP also relied on limited amount of test data from several "new" and "clean" turbines to support its position that the turbines should be able to meet the proposed limits. In the Progress Technical Evaluation and Preliminary Determination (page 23); FDEP states "These limits should be readily met with the use of oxidation catalysts <u>*assuming fast startups and high load operation."*</u> The turbines to be installed at Dahlberg must be capable of extended operation at all loads between 60% and 100% on natural gas and 70% and 100% on fuel oil. The assumption of always operating at high loads, which seems to be part of the emission limit justification for Bartow Unit 5, is not applicable to the Dahlberg units. Both the JEA Greenland facility and the Progress Energy facility selected "good combustion practices" as CO BACT, which is in agreement with the applicant's CO BACT analysis."

GA EPD is in agreement that the limits set should be achievable over the entire range and entire operating time of the unit and should not be based solely on test data at high loads from "new and clean" units. Upon review of the project's cost-effectiveness calculations, which considered a catalyst life of 3 years, the oxidation catalyst technology is only slightly more cost effective when using a catalyst life of 6 years. Given this and the cost effectiveness ranging from $12,000 to $20,000 lbs/ton depending on the catalyst life of 3 to 6 years, good combustion technology and the proposed limits (9 ppm when firing natural gas / 30 ppm when firing fuel oil) will be BACT for the project.

EPD Review - Conclusion – CO Control

The Division has prepared a CO BACT comparison spreadsheet for the similar units using the above-mentioned resources, as discussed in the NOx BACT review, and it is attached in Appendix D. Based on the research performed by the Division and review of the applicant's proposal, GA EPD agrees with the proposed BACT control technology of the use of good combustion controls (such as startup/shutdown limits to 30 minutes per cycle as defined in Condition 3.3.19 of the permit amendment) in the combustion turbines. GA EPD also concurs with the proposed BACT limits of 9 ppm when firing natural gas and 30 ppm when firing fuel oil.

The BACT selection for the combustion turbines (Source Codes: CT11-CT14) is summarized below in Table 4-3.

Table 4-3: BACT Summary for the Combustion Turbines (Source Codes: CT11-CT14)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Practices Natural Gas Good Combustion Practices (ULSD) Oil	9 ppmvd @ 15% O_2 30 ppmvd @ 15% O_2	3 hours 3 hours	Testing Testing
CO	Startup/Shutdown limits	30 minutes per cycle		

Combustion Turbines (Source Codes: CT11-CT14) – VOC Emissions

Applicant's Proposal

Formation of VOC emissions in combustion turbines is attributable to the same factors as described for CO emissions in the section above. VOC emissions are a result of incomplete combustion of carbonaceous fuels, and this is influenced by the temperature and residence time within the combustion zone.

Step 1: Identify all control technologies

Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes VOC from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, VOC will react with oxygen present in the exhaust stream, converting it to carbon dioxide and water vapor. No supplementary reactant is used in conjunction with an oxidation catalyst.

Oxidation catalysts have been employed successfully for two decades, for both natural gas and oil-fired combustion turbines. Similar to SCR systems, for oxidation catalysts to be successful in oil-fired combustion turbine applications, it is generally best when both the amount and the sulfur content of the oil fired are closely restricted, in this case to minimize formation of SOx.

An oxidation catalyst is considered to be technically feasible for application to this project.

Good Combustion Controls

Please refer to the paragraph for Good Combustion Controls as described for CO emissions.

Step 2: Elimination of Infeasible Controls

An oxidation catalyst is a technically feasible control technology for minimizing VOC emissions from simple-cycle turbines firing natural gas or fuel oil. For VOC control, the cost effectiveness is more than $255,000/ton of VOC, as shown in Appendix C of the application. Therefore, the utilization of a high temperature oxidation catalyst would not be cost effective for the proposed simple cycle turbine due to the limited number of operating hours per year

Step 3: Ranking of Available Control Techniques

The available control techniques are Oxidation Catalyst Technology and Good Combustion Controls.

Step 4: Most Effective Control

An oxidation catalyst is a technically feasible control technology and most effective control technology for minimizing VOC emissions from simple-cycle turbines firing natural gas or fuel oil. Oxidation catalysts are capable of reducing potential uncontrolled VOC emissions by approximately 80% annually.

Step 5: Selection of BACT

The utilization of high temperature oxidation catalyst would not be cost effective for the proposed simple cycle turbine due to the limited number of operating hours per year. Consequently, good combustion practices are deemed to be BACT control technology for VOC emissions from the combustion turbines.

The following VOC emission rates are proposed for the combustion turbines:

- 5 ppmvd @ 15% O_2, when firing natural gas (average of 3 one hour tests); and
- 5 ppmvd @ 15% O_2, when firing fuel oil (average of 3 one hour tests).

EPD Review - Conclusion – VOC Control

The Division has prepared a VOC BACT comparison spreadsheet for the similar units using the above-mentioned resources, as discussed in the NOx BACT review, and it is attached in Appendix D. Based on the research performed by the Division and review of the applicant's proposal, GA EPD agrees that the utilization of high temperature oxidation catalyst would not be cost effective for the proposed simple cycle turbine and would be in excess of $200,000 per ton for VOCs in the case of a catalyst life of 3 years or 6 years. GA EPD agrees that the above emissions limits and good combustion controls (such as startup/shutdown limits to 30 minutes per cycle as defined in Condition 3.3.19 of the permit amendment) represents BACT for VOC emissions.

The BACT selection for the combustion turbines (Source Codes: CT11-CT14) is summarized below in Table 4-4:

Table 4-4: BACT Summary for the Combustion Turbines (Source Codes: CT11-CT14)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Good Combustion Practices Natural Gas	5 ppmvd @ 15% O_2	3 hours	Testing
	Good Combustion Practices (ULSD) Oil	5 ppmvd @ 15% O_2	3 hours	Testing
VOC	Startup/Shutdown limits	30 minutes per cycle		

5.0 TESTING AND MONITORING REQUIREMENTS

Requirements for NO_x

NSPS Subpart KKKK requires an initial NO_x performance test using Method 7E. Subpart KKKK requires one of two methods of determining continuous compliance. The first method involves either (a) annual performance tests in accordance with 40 CFR 60.4400, if not using water or steam injection to control NO_x emissions, or (b) the installation of a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine, if burning a fuel that requires water or steam injection for compliance. The second method of determining continuous compliance under Subpart KKKK involves the use of one of the several listed continuous monitoring systems, including a continuous emission monitoring system as described in 40 CFR 60.4335(b) and 60.4345.

Continuous compliance with the NO_x emission limitations of Subpart KKKK will be demonstrated with a NO_x CEMS in keeping with 40 CFR 60.4335(b)(1), 60.4340(b)(1), and 60.4345. Each NO_x CEMS must be installed and certified according to Performance Specification 2 of 40 CFR Part 60, Appendix B, except that the 7-day calibration drift is to be based on unit operating days, not calendar days.

Three-hour rolling NO_x emission measurements by the NO_x CEMS satisfy the periodic monitoring requirement for the non-NSPS NO_x emission limits. The three-hour rolling NO_x emission measurements will also satisfy the Subpart KKKK NO_x emission limits, even though those limits are based on a four-hour rolling average because, for the same numerical value, an emission limit based on a three-hour average is more stringent than one based on a four-hour average. Therefore, provided that the three-hour NO_x CEMS average concentrations are less than either 15 ppm (firing natural gas) or 42 ppm (firing fuel oil), the Division concludes that the NO_x CEMS can be used to demonstrate continuous compliance with the Subpart KKKK NO_x emission limits. An excess emissions for NSPS purposes, therefore, will consist of any unit operating period in which the 3-hour rolling average NO_x emission rate exceeds either 15 ppm (firing natural gas) or 42 ppm (firing fuel oil).

The Acid Rain regulations require that the NO_x mass emission rate from each combustion turbine is measured and recorded. The Permittee must ensure that the NO_x CEMS meets all applicable criteria of 40 CFR Part 75, including the general requirements of 40 CFR 75.10, the specific provisions of 40 CFR 75.12, the equipment, installation, and performance specifications in Appendix A, and the quality assurance and quality control procedures in Appendix B. The recently promulgated Clean Air Interstate Rule (CAIR) also requires the monitoring of NO_x mass emissions. Satisfaction of the 40 CFR Part 75 Acid Rain NO_x monitoring requirements mentioned above, including Part 75, Subpart H (NO_x Mass Emissions Provisions), will assure compliance with the CAIR monitoring requirements.

To reasonably assure compliance with the BACT NO_x emission limitations, the Permittee must install, calibrate, operate, and maintain a NO_x CEMS for periodic monitoring of NO_x emissions from each combustion turbine.

Requirements for CO

Compliance with the BACT CO emission limitations for each combustion turbine must be demonstrated by an initial performance test using Method 10, the method for compliance determination. For each of the simple-cycle systems (Combustion Turbines CT11, CT12, CT13, and CT14), separate tests must be conducted while burning natural gas and ultra low sulfur diesel fuel.

Requirements for SO_2

NSPS Subpart KKKK requires the total sulfur content of the fuel to be monitored. However, if a fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input, then the Permittee may elect not to monitor the sulfur content of that fuel. In keeping with the provisions of 40 CFR 60.4365, the Permittee will therefore demonstrate that neither the pipeline quality natural gas nor the ultra low sulfur diesel fuel contains potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu.

NSPS Subpart KKKK requires initial and subsequent performance tests for sulfur. Section 60.4415 (a)(1) allows the facility to provide fuel analyses of this section by the facility or a third party in lieu of performance testing. Therefore, initial and annual performance testing for SO_2 is not required.

The Acid Rain regulations require that SO_2 mass emissions from each combustion turbine be measured and recorded. One option for satisfying that requirement is to use applicable procedures specified in Appendix D to 40 CFR Part 75 for estimating hourly SO_2 mass emissions. SO_2 mass emissions from firing pipeline quality natural gas will be estimated using the regulatory default SO_2 emission rate of 0.0006 lb SO_2/MMBtu and the applicable quantity of natural gas burned in the combustion turbine. The heat content for the natural gas is 1020 Btu/scf. SO_2 mass emissions from Combustion Turbines CT11, CT12, CT13 and CT14 firing ultra low sulfur diesel fuel will be calculated based on the average sulfur content and heat content of that oil and the quantity of that oil which is burned. The sulfur content and heat content of that oil will be provided by appropriate certifications from the fuel suppliers. The Permittee will also have the flexibility to monitor the sulfur content and heat content of that oil using "as-received" samples instead of fuel-supplier certifications. The Division believes that this method of compliance is acceptable provided that the sulfur content of all oil delivered meets the applicable limit, which is 15 ppm.

The recently promulgated Clean Air Interstate Rule (CAIR) also requires the monitoring of SO_2 mass emissions. Satisfaction of the 40 CFR Part 75 Acid Rain SO_2 monitoring requirements will assure compliance with the CAIR monitoring requirements.

Requirements for VOC

Method 25A performance testing will be the compliance determination method for VOC. There is no reliable and readily available method for long-term, continuous monitoring of VOC emissions from the type of fuel-burning equipment proposed by the Permittee. The performance tests for carbon monoxide and volatile organic compounds shall be conducted concurrently.

With the use of good combustion practices, pipeline quality natural gas, and Ultra low Sulfur Distillate (USLD) fuel, the Division concurs, that no monitoring of VOC will be required except for the semi-annual submittal of the percent sulfur in the fuel via a fuel analysis.

Requirements for Particulate Matter and Opacity

Natural gas and USLD fuel are both low-ash fuels. Consequently, the Division believes each simple-cycle system will emit negligible amounts of particulate matter and visible emissions. Each system will be tested while its combustion turbine fires natural gas and also while it fires ultra low sulfur diesel. Compliance with the particulate matter and visible emissions limits will be determined using Method 5T and Method 9, respectively. Method 9 also will be the basis for periodic monitoring of visible emissions, when the Division deems necessary.

With the use of good combustion practices, pipeline quality natural gas, and USLD fuel, the Division concurs, that no monitoring of PM_{10} will be required except for the semi-annual submittal of the percent sulfur in the fuel via a fuel analysis.

CAM Applicability:

The Combustion Turbines (Source Codes: CT11-CT14) are subject to the requirements of compliance assurance monitoring (CAM) as specified in 40 CFR 64. CAM is only applicable to emission units that have potential emissions greater than the major source threshold, located at a major source, use a control device to control a pollutant emitted in an amount greater than the major source threshold for that pollutant, and have a specific emission standard for that pollutant. The Combustion Turbines (Source Codes: CT11-CT14) uses a water injection system to control NOx emissions while firing fuel oil. Refer to Section 3.0 “Review of Applicable Rules and Regulations” of this document for more detail on the CAM requirements for Combustion Turbines (Source Codes: CT11-CT14).

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 exist 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 Plant Dahlberg triggers PSD review for NO_2, PM_{10}, CO, and VOC. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD increment standards for NO_2, PM_{10}, and CO. 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 NO_2, PM_{10}, 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. VOC does not have an established PSD modeling significance level (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm). 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 Jackson County and the level of emissions increases that will result from the proposed project. The southeast is generally NO_2 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 NO_2, PM_{10}, CO and VOC emissions increases at Plant Dahlberg would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established modeling significant levels (MSLs). The MSLs for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the significant impact level (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 NO_2, PM_{10}, and CO.

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. $PM_{2.5}$ does not yet have established MSLs (3 options proposed on 9/12/07)

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (SIL) (μg/m^3)	PSD Monitoring Deminimis Concentration (μg/m^3)
SO_2	Annual	1	--
	24-Hour	5	13
	3-Hour	25	--
PM_{10}	Annual	1	--
	24-Hour	5	10
NOx	Annual	1	14
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 (μg/m^3)	Primary / Secondary (ppm)
PM_{10}	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
$PM_{2.5}$	Annual	15 / 15	--
	24-Hour	35 / 35	--
NOx	Annual	100 / 100	0.053 / 0.053
CO	8-Hour	10,000 / None	9 / None
	1-Hour	40,000 / None	35 / None
Pb	3-month	1.5/None	--

If the maximum pollutant impact calculated in the Significance Analysis exceeds the MSL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at Plant Dahlberg, 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 NOx, SO_2, and PM_{10}; no increments have been established for CO or $PM_{2.5}$ (however, $PM_{2.5}$ increments are expected to be added soon). The PSD Increments are further broken into Class I, II, and III Increments. Plant Dahlberg 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 (µg/m^3)	Class II (µg/m^3)
PM_{10}	Annual	4	17
	24-Hour	8	30
NOX	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 MSL 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 NOx 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 Sections 6 and 7 of the permit application and the EPD modeling memo dated May 7,2009 included in Appendix C.

Modeling Results

Table 6-4 show that the proposed project will not cause ambient impacts of NOx, CO and PM_{10} above the appropriate SIL. Because the emissions increases from the proposed project result in ambient impacts less than the SIL, no further PSD analyses were conducted for these pollutants.

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

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (µg/m^3)	SIL (µg/m^3)	Significant?
NO_2	Annual	1990	279.0	3768.9	0.210	1	No
PM_{10}	24-hour	1990	279.5	3768.8	2.54	5	No
	Annual	1992	279.0	3768.9	0.05	1	No
CO	1-hour	1990	278.1	3768.4	128.97	2000	No
	8-hour	1989	279.3	3768.7	31.95	500	No

Data for worst year provided only. Results are the maximum of Four (4) Load Groups; 100EVAP, 100LD, 80LD and 60LD and Dual-fuel Operations.

During start-up of simple cycle combustion turbines, emissions of CO may be elevated for a period long enough to affect short-term average concentrations. A worst-case start-up scenario was assessed for comparison to the short-term SILs for CO (1-hour and 8-hour average) Table 6-5 summarizes the startup/shutdown parameters that were modeled and Table 6-6 contains the results. Emissions calculations are presented in Appendix B of the application.

Table 6-5: Source Parameters and Emission Rates – Startup/Shutdown

Pollutant	Scenario	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (^oF)	Exit Velocity (fps)	Emissions (lbs/hr)
1-Hour	Startup/Shutdown	60	26.13	927.5	59.70	720
	Normal Operation	60	26.13	1013	69.03	88
8-Hour	Startup/Shutdown	60	26.13	927.5	59.70	270
	Normal Operation	60	26.13	1013	69.03	106

Table 6-6: CO Startup SIL Modeling Results

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Year Modeled	SIL ($\mu g/m^3$)
CO	1-hour	128.97	1990	2000
CO	8-hour	31.95	1989	500

As indicated in the tables above, maximum modeled impacts were below the corresponding SIL for CO. Therefore, no further CO modeling of the start-up conditions is required.

Ambient Monitoring Requirements

Table 6-7: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
NO_2	Annual	1990	279.0	3768.9	14	0.0282	No
PM_{10}	24-hour	1990	279.5	3768.8	10	2.545	No
SO_2	24-hour	N/A	NS	NS	13	NS	NS
CO	8-hour	1989	279.3	3768.7	575	31.95	No

Data for worst year provided only. NS = Emission rate less than significant emission rate.

For details on the de minimis concentrations, see the Modeling memo in Appendix C.

The impacts for NOx, CO, SO_2, and PM_{10} quantified in Table 6-7 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, CO, SO_2, and PM_{10}.

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 do not exceed 100 tpy. As ozone precursors, an ambient ozone impacts analysis must be conducted if VOC or NOx project net emissions increases exceed 100 tpy. Proposed NOx emissions of the project are 1190 tpy. However, the proposed NOx emissions must be offset by 110%. Therefore, the net project emissions of NOx and VOC will be less than 0 tpy and 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 300 kilometers has been used for all facilities.

The four Class I areas within approximately 200 kilometers of Plant Dahlberg are the Cohutta Wilderness, Joyce-Kilmer Wilderness, Shining Rock Wilderness and Great Smoky Mountains National Park located approximately 142, 154, 153 and 160 kilometers respectively with the first two areas, North West and the second two areas, North East and North of the facility. The U.S. Forest Service (USFS) is the designated Federal Land Manager (FLM) responsible for oversight of the Wilderness areas and the National Park Service for the National Park.

As shown in table 1-3, the proposed project will result in emission increases of criteria pollutants, above the Prevention of Significant Deterioration (PSD) threshold limits. Therefore, PSD review was required for the criteria pollutants and thus a subsequent Class I modeling analysis was required for NO_x and PM_{10} only. CO was not modeled because there are no Class I SIL established for CO. In addition nitrogen deposition as well as regional haze was assessed. CO was not included in the visibility analysis because it is not considered as a visibility affecting pollutant.

Since the Class I areas are located more than 50 km from the proposed facility, the CALPUFF model, Version 5.8 (level 070623), along with CALMET, the meteorological pre-processor, was applied in a refined mode (Scire et al., 2000a,b). The Class I areas were assessed on the 100% load operation of the proposed new simple cycle turbines. The 100% load case is the only case modeled due to the fact that it is the worst-case scenario for long range modeled impacts because it is associated with the highest emissions and greatest plume rise resulting in the greatest potential for distant plume transport.

For the assessment of the modeled PSD increment, the proposed project was modeled with the emissions and stack parameters presented in Tables 6-8 thru 6-10. No other ancillary equipment were modeled for the Class I area impact analysis because they are either emergency in nature, have very infrequent usage, or have very localized impacts within a few kilometers of the facility.

Table 6-8: Short Term and Annual Emissions Data and Stack Parameters for proposed SGT6-5000F Simple-Cycle Combustion Turbines – Natural Gas Operation

Fuel	Turbine Type	Turbine Load	Stack Velocity (ft/s)	Exhaust Temp (^oF)	NOx (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)
Short-Term Emission Rates								
Natural Gas	Simple Cycle	100%	76.18 (1)	1047.0(1)	75.00	9.1	(3)	(3)
Annual Emission Rates								
Natural Gas	Simple Cycle	100%	76.18 (1)	1047.0(1)	34.25(2)	4.16(2)	(3)	(3)

(1) Stack parameters represent the worst-case fuel stack parameters.
(2) Annual emission rates based on 4,000 hours of Natural Gas operation.
(3) Emission estimates indicate that SO_2 and H_2SO_4 were not subject to PSD review. Therefore modeling for SO_2 analysis was not performed.

Table 6-9: Short Term Emissions Data and Stack Parameters for proposed SGT6-5000F Simple-Cycle Combustion Turbines – Fuel Oil Operation

Fuel	Turbine Type	Turbine Load	Stack Velocity (ft/s)	Exhaust Temp (°F)	NOx (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)
Short-Term Emission Rates								
Natural Gas	Simple Cycle	100%	74.63 (1)	1013.0(1)	360.00	69.00	(2)	(2)

(1) Stack parameters represent the worst-case fuel stack parameters.
(2) Emission estimates indicate that SO_2 and H_2SO_4 were not subject to PSD review. Therefore modeling for SO_2 analysis was not performed.

Table 6-10: Annual Emissions Data and Stack Parameters for proposed SGT6-5000F Simple-Cycle Combustion Turbines – Dual Fuel Oil Operation

Fuel	Turbine Type	Turbine Load	Stack Velocity (ft/s)	Exhaust Temp (°F)	NOx (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)
Annual Emission Rates								
Natural Gas	Simple Cycle	100%	74.63 (1)	1013.0(1)	66.78(2)	10.99(2)	(3)	(3)

(1) Stack parameters represent the worst-case fuel stack parameters.
(2) Annual emission rates based on 4,000 hours of operation; 3,000 hour on natural gas and 1,000 hours on fuel oil.
(3) Emission estimates indicate that SO_2 and H_2SO_4 were not subject to PSD review. Therefore modeling for SO_2 analysis was not performed.

PSD Increment Analysis

The following Tables 6-11 thru 6-14 compares the project impacts versus the significance levels in these Class I areas

Table 6-11: Class I Significance Analysis Results – Comparison to MSLs – Cohutta Wilderness

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (µg/m³)	MSL (µg/m³)	Significant?
NO_2	Annual	2002	279.0	3858.4	0.0039	0.1	No
PM_{10}	24-hour	2003	279.5	3861.0	0.1599	0.3	No
	Annual	2002	279.0	3858.4	0.0011	0.2	No
SO_2	Annual	N/A	NS			0.1	NS
	24-hour	N/A				0.2	
	3-hour	N/A				1.0	

Data for worst year provided only. Results are the maximum of Four (4) Load Groups; 100EVAP, 100LD, 80LD and 60LD and Dual-fuel Operations. NS = Emission rate less than significant emission rate

Table 6-12: Class I Significance Analysis Results – Comparison to MSLs – Joyce-Kilmer-Slickrock Wilderness

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (µg/m³)	MSL (µg/m³)	Significant?
NO_2	Annual	2002	230.8	3916.2	0.0017	0.1	No
PM_{10}	24-hour	2002	230.8	3916.2	0.0702	0.3	No
	Annual	2002	230.8	3916.2	0.0006	0.2	No
SO_2	Annual	N/A	NS			0.1	NS
	24-hour	N/A				0.2	
	3-hour	N/A				1.0	

Data for worst year provided only. Results are the maximum of Four (4) Load Groups; 100EVAP, 100LD, 80LD and 60LD and Dual-fuel Operations. NS = Emission rate less than significant emission rate

Table 6-13: Class I Significance Analysis Results – Comparison to MSLs – Shining Rock Wilderness Area

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (µg/m^3)	MSL (µg/m^3)	Significant?
NO_2	Annual	2003	331.5	3911.8	0.0018	0.1	No
PM_{10}	24-hour	2003	334.5	3911.8	0.1079	0.3	No
	Annual	2003	327.2	3912.8	0.0007	0.2	No
SO_2	Annual	N/A	NS			0.1	NS
	24-hour	N/A				0.2	
	3-hour	N/A				1.0	

Data for worst year provided only. Results are the maximum of Four (4) Load Groups; 100EVAP, 100LD, 80LD and 60LD and Dual-fuel Operations. NS = Emission rate less than significant emission rate

Table 6-14: Class I Significance Analysis Results – Comparison to MSLs – Great Smoky Mountains National Park

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (µg/m^3)	MSL (µg/m^3)	Significant?
NO_2	Annual	2003	279.0	3928.8	0.0018	0.1	No
PM_{10}	24-hour	2002	279.5	3926.8	0.0824	0.3	No
	Annual	2003	279.0	3928.8	0.0005	0.2	No
SO_2	Annual	N/A	NS			0.1	NS
	24-hour	N/A				0.2	
	3-hour	N/A				1.0	

Data for worst year provided only. Results are the maximum of Four (4) Load Groups; 100EVAP, 100LD, 80LD and 60LD and Dual-fuel Operations. NS = Emission rate less than significant emission rate

The modeling results indicate that the proposed project at Plant Dahlberg will have an insignificant impact on NOx and PM_{10} increments at all PSD Class I areas assessed as a part of this analysis. Therefore, no further PSD increment analysis is required. It has also been demonstrated that the proposed project should not have an adverse impact on visibility or deposition. Refer to Section 8 of the application and the EPD modeling memo in Appendix C, for detailed Class I modeling information.

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 project lies in an area of primarily agricultural use with surrounding swamplands. An analysis of the project's potential impact on soils and vegetation in the vicinity of the facility was performed in accordance with the procedures recommended in EPA's "A Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils and Animals" (EPA-450/2-81-078). This referenced document establishes criteria for sensitive vegetation and crops exposed to the effects of the gaseous pollutants through direct exposure. Adverse impacts on soil systems result more readily from the secondary effects of these pollutants' impacts on the stability of the soil system. These impacts could include increased soil temperature and moisture stress and/or increased runoff and erosion resulting from damage to vegetative cover. The highest predicted pollutant impacts from the facility used in the NAAQS compliance analysis were compared to the screening concentrations listed in the above referenced document and as shown in Table 7.1 below to demonstrate compliance.

Table 7-1: Comparison to EPA Criteria for Gaseous Pollutant Impacts on Natural Vegetation and Crops

Pollutant	Averaging Period	Minimum Impact Level for Effects on Sensitive Plants (μg/m3)	Maximum Impact of Proposed Facility (μg/m3)
NOx	4-hour	3,760	41.63
	8-hour	3,760	29.93
	1-month	564	3.37
	Annual	94	0.3
CO	1-week	1,800,000	4.05*
*24-hour average used to conservatively represent 1-week average impact.			

As can be seen from Table 7.1, the results clearly indicate that no adverse impacts will occur to sensitive vegetation, crops or soils systems as a result of operation of the proposed project.

Growth

A qualitative assessment was made as to the project's potential to cause general commercial, residential, industrial or other secondary growth in the area. During operation, the modification is not expected to employ additional people. There should be no substantial increase in community growth, or need for additional infrastructure. Therefore, it is not anticipated that the proposed action will result in secondary growth associated with non-project related activities.

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.

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 any exhaust plume visibility analysis, a Level-1 visibility analysis can be 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. GA EPD recommended in a letter dated June 5, 2008, that VISCREEN not be conducted as there are no sensitive receptors located in the maximum significant impact area.

However, a regional haze analysis was performed using CALPUFF and CALPOST processing to compute the maximum 24-hour average light extinction due to NOx and PM10 emissions from the proposed combustion turbine stacks at Cohutta Wilderness, Joyce-Kilmer Wilderness, Shining Rock Wilderness and Great Smokey Mountains National Park. Further details of the regional haze analysis can be found in Section 8 of the application. The proposed facility will not have an adverse impact on air quality related values or visibility at any of the four Class I areas.

Acidic Deposition

CALPUFF, POSTUTIL amd CALPOST were applied to obtain upper limit estimates of annual wet and dry deposition of nitrogen compounds (kg/ha/yr) associated with emissions from the proposed simple cycle turbine stacks at Cohutta Wilderness, Joyce-Kilmer Wilderness, Shining Rock Wilderness and Great Smokey Mountains National Park. Specifically CALPUFF was used to model both wet and dry deposition of nitrogen (N) at the mentioned Class I areas. Further details of the acid deposition analysis can be found in Section 8 of the application. The result of the analysis is that no adverse impact from nitrogen deposition is expected.

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)*."

Acceptable Ambient Concentrations (AACs) were calculated for each contaminant and applicable time-averaging period according to the Georgia Air Toxics Guideline, as shown on Table 8-21 (as modified), attached to the model request forms. Maximum ground-level concentrations (MGLCs) of each evaluated contaminant emitted from each source on the Plant Dahlberg site were assessed without downwash using maximum capacity emission rates and source characteristics. All air toxic concentrations assessed were found to be less than their respective AAC concentrations.

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 emissions 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 ultra low sulfur distillate fuel 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.

Section 8.4 of Application 18326 contains discussion of how toxic emissions were determined. 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. Plant Dahlberg 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.

All air toxics evaluated by the applicant meet the applicable Georgia Air Toxics Guideline Acceptable Ambient Concentrations (AACs). The ISCST3 model was conservatively used in review of the air toxics.

Modeling Results

Please refer to the EPD modeling memorandum dated May 7, 2009. This memorandum has been included in Appendix C.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-157-0034-V-04-1.

Section 1.0: Facility Description

The construction and operation of four additional simple cycle combustion turbines which can produce nominally 760 MW of electricity and are capable of firing natural gas or ultra low sulfur fuel oil. New auxiliary support equipment will include one fuel oil storage tank.

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

Table 3.1.1 is updated to include the four additional simple cycle combustion turbines (Source Codes: CT11-CT14).

New Condition 3.3.17 limits the sulfur content of the fuel fired in the combustion turbines (Source Codes: CT11-CT14) to 0.0015 percent, by weight.

New Condition 3.3.18 defines the BACT controls for NOx when the combustions turbines (Source Codes: CT11-CT14) are firing natural gas and fuel oil.

New Condition 3.3.19 applies the current permit startup and shutdown definitions to the new combustion turbines (Source Codes: CT11-CT14).

New Condition 3.3.20 states that the new combustion turbines are subject to NSPS 40 CFR 60 Subpart A –“General Provisions” and Subpart KKKK – “Standards of Performance for Stationary Combustion Turbines”.

New Condition 3.3.21 defines heat input limit for the new combustion turbines (Source Codes: CT11-CT14).

New Condition 3.3.22 defines the total consumption limit of fuel oil fired in the combustion turbines (Source Codes: CT11-CT14).

New Condition 3.3.23 defines the BACT limit for NOx when the combustions turbines (Source Codes: CT11-CT14) are firing natural gas.

New Condition 3.3.24 defines BACT limits for CO, particulate matter and VOCs when the combustion turbines (Source Codes: CT11-CT14) are firing natural gas.

New Condition 3.3.25 states the nitrogen oxides limit defined by Subpart KKKK.

New Condition 3.3.26 states the sulfur limit defined by Subpart KKKK.

New Condition 3.2.27 defines the BACT limit for NOx when the combustion turbines (Source Codes: CT11-CT14) are firing fuel oil.

New Condition 3.2.28 defines the BACT limits for CO, particulate matter and VOCs when the combustion turbines (Source Codes: CT11-CT14) are firing fuel oil.

New Condition 3.3.29 defines the Ultra Low Sulfur limit to 0.0015 percent sulfur by weight (15 ppm) for fuel oil fired in the combustion turbines (Source Codes: CT11-CT14).

New Condition 3.3.30 requires the Permittee to commence construction of the combustion turbines (Source Codes: CT11-CT14) within 18 months of permit issuance.

New Condition 3.3.31 requires the Permittee to provide documentation to the Division that external emission reduction credits for nitrogen oxide (1309 tpy) emissions have been obtained at least 30 days prior to operating the combustion turbines (Source Codes: CT11-CT14) per Georgia State Rule 391-3-1-03(8)(c)12 and 391-3-1-.03(8)(c)15

New Condition 3.3.32 defines the 30-day rolling average limit for NOx as 15 ppmvd @15% oxygen. This limit includes emissions during startup and shutdown while firing natural gas.

New Condition 3.3.33 defines the annual twelve consecutive month limit for NOx as 297.5 tons for each combustion turbine (Source Codes: CT11-CT14). This limit includes emissions during startup and shutdown while firing either natural gas or fuel oil.

New Condition 3.4.2 states the Georgia State Rule 391-3-1-.02(2)(b)1 requirements not to exceed 40% opacity at the exhausts for the simple cycle combustion turbines (Source Codes: CT11-CT14).

New Condition 3.4.3 states the Georgia State Rule 391-3-1-.02(2)(g)2 requirements not to exceed 3% sulfur by weight in any fuel fired in the simple cycle combustion turbines (Source Codes: CT11-CT14).

Section 4.0: Requirements for Testing

Condition 4.1.3 was updated to state the general testing requirements for the four additional simple cycle combustion turbines (Source Codes: CT11-CT14).

New Condition 4.2.1 requires the facility to conduct NOx testing in accordance with 40 CFR 60 Subpart KKKK.

New Condition 4.2.2 was added to state the specific testing requirements for PM, VOC and CO for the four (4) additional simple cycle combustion turbines (Source Codes: CT11-CT14).

Section 5.0: Requirements for Monitoring

New Condition 5.2.8 was added to provide the specific monitoring requirements (NOx CEMS) for the four new simple cycle combustion turbines (Source Codes: CT11-CT14).

New Conditions 5.2.9 and 5.2.10 were added to state that the four new simple cycle combustion turbines (Source Codes: CT11-CT14) are subject to Compliance Assurance Monitoring (CAM) Rule in 40 CFR 64 and the CAM Plan requirements.

New Condition 5.2.11 was added to include the one-hour average nitrogen oxides emissions calculations for the four simple cycle combustion turbines (Source Codes: CT11-CT14).

New Conditions 5.2.12 and 5.2.13 were added to provide the specific monitoring requirements for the four new simple cycle combustion turbines (Source Codes: CT11-CT14).

New Condition 5.2.14 defines the monitoring requirements for the NOx 30-day rolling average.

Section 6.0: Other Recordkeeping and Reporting Requirements

Condition 6.1.7 was updated to provide general reporting requirements for the four new simple cycle combustion turbines (Source Codes: CT11-CT14).

New Conditions 6.2.11, 6.2.12, 6.2.13, 6.2.14, 6.2.15, 6.2.16, 6.2.17, 6.2.18. 6.2.19, 6.2.20 and 6.2.21 were added to provide specific recordkeeping and reporting requirements for the four new simple cycle combustion turbines (Source Codes: CT11-CT14).

Section 7.0: Other Specific Requirements

New Condition 7.14.1 was added to void the permit amendment if commencement of construction for the new combustion turbines has not occurred within eighteen months of the permit amendment issuance. This is a PSD requirement.

APPENDIX A

Draft Revised Title V Operating Permit Amendment
Dahlberg Combustion Turbine Electric Generating Facility (Plant Dahlberg)
Nicholson, (Jackson County), Georgia

APPENDIX B

Dahlberg Combustion Turbine Electric Generating Facility (Plant Dahlberg)
PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 18326, dated July 08, 2008
2. Additional Information Package Dated November 12, 2008
3. Additional Information Letter Dated March 3, 2009
4. Additional Information Letter Dated July 29, 2009

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review

APPENDIX D

EPD'S BACT Analysis Spreadsheets