

**Prevention of Significant Air Quality Deterioration Review
of a Major Modification and a Part 70 Significant Modification Review
at the Georgia Power Company
Wansley Steam-Electric Generating Plant
located in Roopville, Heard County, Georgia**

**PRELIMINARY DETERMINATION
SIP Permit Application No. 11857
Phase II Acid Rain Permit Application No. 11828
Part 70 Permit Application No. TV-12224**

**State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch**

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May 2000**

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the Georgia Power Company's application to construct and operate four combustion turbine combined-cycle blocks at the Wansley Steam-Electric Generating Plant (Plant Wansley), in Roopville, Heard County, Georgia, resulting in approximately 2,280 MW of power. Each combined-cycle block will include two combustion turbines each with a supplementally fired (duct burner) heat recovery steam generator (CT/HRSG) and associated support facilities. Each block will have one steam turbine. This arrangement of equipment is referred to as a two-on-one configuration, and each block will have a rated output capacity of 570 MW. Each combustion turbine (General Electric 7FA) will generate approximately 170 MW of electric power and will fire only pipeline quality natural gas. Each duct burner, manufactured by Coen, will also fire only natural gas. The manufacturer of the HRSGs will be Vogt-NEM. The GE steam turbine will generate approximately 230 MW of electric power.

The combustion turbines and duct burners will be equipped with dry low NO_x combustors/burners for control of NO_x emissions. NO_x emissions from the combined turbine/duct burner stack will be controlled by selective catalytic reduction post air pollution combustion control. The combined-cycle block facility will be permitted as a base load facility with the capability of operating in power augmentation mode. The estimated potential emissions of regulated pollutants from the facility are as follows: Particulate Matter with an aerodynamic diameter less than 10 microns (PM₁₀) = 700.8 tons per year; Particulate Matter (PM) = 700.8 tons per year; Nitrogen Oxides (NO_x) = 1040.7 tons per year; Carbon Monoxide (CO) = 4860.1 tons per year; Sulfur Dioxide (SO₂) = 52.6 tons per year; Volatile Organic Compounds (VOC) = 322.37 tons per year; Lead (Pb) = approximately zero tons per year; Sulfuric Acid Mist (H₂SO₄) = approximately zero tons per year.

The location of the combustion facility in Heard County is classified as "attainment" for PM₁₀, NO_x, CO, SO₂ and Ozone in accordance with Section 107 of the Clean Air Act, as amended August 1977; however, Heard County, Georgia is classified as an area which contributes to the ambient air levels of ozone in the metropolitan Atlanta ozone nonattainment area.

The EPD review of the data submitted by Georgia Power for the construction and operation of the combustion turbine facility indicates that compliance with all applicable State and Federal air quality regulations will be achieved.

It is the Preliminary Determination of EPD that the proposal provides for the application of best available control technology (BACT) for the control of NO_x, CO, SO₂, PM, PM₁₀, and VOC as required by Federal PSD regulation 40 CFR 52.21(j) and Georgia Rule 391-3-1-.03(8)(c)15. Georgia Power will be required to obtain emission offsets of NO_x at a ratio of at least 1.1 to 1.0 to satisfy the offset requirements of Georgia Rule 391-3-1-.03(8)(c)15.

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. 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.

The Preliminary Determination indicates that an Air Quality Permit should be issued to Georgia Power for the construction and operation of the combined-cycle blocks. Various conditions will be made a part of the permit to construct and operate in order to insure and confirm compliance with all applicable regulations. A copy of the draft permit is provided in Appendix A.

1.0 INTRODUCTION

The Georgia Environmental Protection Division (EPD) has finalized Georgia Rule 391-3-1-.03(8)(c) and (e), as part of the new State Implementation Plan (SIP) for the Atlanta ozone nonattainment area requiring the application of BACT-Offset requirements for any area determined and designated by EPD to contribute to the ambient air levels of ozone in the Atlanta thirteen county nonattainment area. Georgia Rule 391-3-1-.03(8)(e) specifies that no permit to construct a new or modified major stationary source in Heard County, Georgia shall be issued unless such proposed source meets all the requirements of Georgia Rule 391-3-1-.03(8)(c). Georgia Rule 391-3-1-.03(8)(c)15. specifies additional provisions for electrical generating units located in Heard County, Georgia and is referred to as the BACT-Offset Rule.

The additional requirements of Georgia Rule 391-3-1-.03(8)(c) are (1) obtain NO_x offsets at a 1.1 to 1 ratio by the time the source is to commence operation; (2) Application of best available control technology (BACT) for each regulated pollutant that would be emitted in significant amounts; (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) a site selection analysis.

The regulations for Prevention of Significant Air Quality Deterioration (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 for 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 all other sources having potential emissions of 250 tons per year or more of any regulated pollutant; or modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements: (1) Application of best available control technology (BACT) for each regulated pollutant that would be emitted in significant amounts; (2) Analysis of the ambient air impact; (3) Analysis of the impact on soils, vegetation, and visibility; (4) Analysis of the impact on Class I areas; and (5) Public notification of the proposed plant in a newspaper of general circulation.

On November 30, 1999, Georgia Power submitted an application for an air quality permit to construct and operate four combustion turbine combined-cycle blocks at the Wansley Steam-Electric Generating Plant (Plant Wansley), in Roopville, Heard County, Georgia. Each combined-cycle block will include two combustion turbines each with a supplementally fired (duct burner) heat recovery steam generator (CT/HRSG) and associated support facilities. Each block will have one steam turbine. This arrangement of equipment is referred to as a two-on-one configuration, and each block will have a rated output capacity of 570 MW. Each 570 MW block will consist of two General Electric (GE) 7FA combustion turbines. Each combustion turbine will generate approximately 170 MW of electric power and will fire only pipeline quality natural gas. Each duct burner, manufactured by Coen, will also fire only natural gas. The manufacturer of the HRSGs is Vogt-NEM. The GE steam turbine will generate approximately 230 MW of electric power.

Georgia Power anticipates operating the combustion turbines and duct burners in power augmentation mode for approximately 1,000 hours and at base load without power augmentation for the remaining 7,760 hours per year. The Wansley combined-cycle facility is designed to be operated as a baseload facility. However, the actual annual load factor will depend on a number of factors including electricity demand and market price signals. The plant is designed such that the number of starts could range from as few as 20 to as many as 230 starts per year over the

life of the units. Due to the relatively high cost for each startup and maintenance issues relative to multiple starts, the goal is to keep the number of starts to significantly less than 100 per year, with 65 to 70 per year being in the “normal” range.

Each combustion turbine and duct burner will be equipped with dry low NOx burners to control emissions of NOx, and selective catalytic reduction post air pollution control equipment will be used to control emissions from the combined turbine and duct burner stack. The combustion turbines and duct burners will only use natural gas as the fuel. Emissions of SO₂ will be minimized by restricting fuel use to only natural gas. Emissions of CO and VOC will be controlled by efficient combustion of the fuel. The use of clean, low-ash fuels and efficient combustion will limit the emissions of PM, PM10, and lead.

Georgia Power’s application and supporting data are included in Appendix B.

The potential to emit of regulated air pollutants under this proposal are illustrated in Table 1.

Table 1. Emissions Summary of Proposed Modification at Plant Wansley

Pollutant	PTE (TPY)	Significant Emissions Level (TPY)	BACT Required?	Pollutant	PTE (TPY)	Significant Emissions (TPY)	BACT Required?
CO(1)	4,860.1	100	YES	Fluorides (as HF) (3)	~0	3	NO
NOx (1)	1,040.7	40	YES	Benzene (4)	0.103	NA	NA
SO ₂ (2)	52.6	40	YES	Arsenic (4)	0.0038	NA	NA
PM (1)	700.8	25	YES	Formaldehyde (4)	0.54	NA	NA
PM ₁₀ (1)	700.8	15	YES	Acetaldehyde	0.88	NA	NA

Pollutant	PTE (TPY)	Significant Emissions Level (TPY)	BACT Required?	Pollutant	PTE (TPY)	Significant Emissions (TPY)	BACT Required?
				(4)			
VOC (1)	595.68	40	YES	Acrolein (4)	0.49	NA	NA
Lead (3)	~0	0.60	NO	Ethyl benzene (4)	1.84	NA	NA
Beryllium	~0	NA	NA	Naphthalene (4)	0.044	NA	NA
Mercury (4)	0.034	NA	NA	PAH (4)	0.064	NA	NA
Vinyl Chloride	~0	NA	NA	Toluene (4)	1.68	NA	NA
Sulfuric Acid Mist (3)	~0	7	NO	Xylene (4)	2.12	NA	NA

(1) Taken from page 1-7 of Application No. 11857; (2) Taken from page 3-5 of Application No. 11857

(3) Taken from page 3-7 of Application No. 11857; (4) Calculations can be found in Appendix B of this Preliminary Determination

Potential emissions, for the most part, are based on the highest hourly emission rate for the turbine and duct burner even if that combination is not realistic. The exception to this manner of computing emissions is for NOx where Georgia Power wanted to be more realistic in what is to be expected since they must obtain emission offsets.

Based on the information in Table 1, Georgia Power's proposed modification to Plant Wansley is classified as a major modification to a major source under the BACT-Offset rule, Georgia Rule 391-3-1-.03(8)(c)15.(ii), because potential emissions of NOx exceed 40 tons per year.

Georgia Power has demonstrated to EPD that all of their owned and operated major stationary sources in Georgia are in compliance with all applicable emission limitations and standards based on recent EPD inspections.

Georgia Power submitted a site selection analysis as required by Georgia Rule 391-3-1-.03(8)(c)(4). There are several factors that make the existing Plant Wansley site preferable to other alternative facility locations. These include the (1) demand for power and load growth in the area, (2) access to existing transmission facilities, and (3) proximity to the gas pipeline. In addition, the Plant Wansley site is an existing site that was originally designed for four coal-fired units (only two were constructed), and thus, it has adequate real property to accommodate the proposed combined-cycle operations.

Moreover, the Plant Wansley site is a remote, large site with adequate water and infrastructure to support the combined-cycle units without impacting the surrounding communities. Other potential alternative sites would require developing a green-field site. At a minimum, this would require building additional transmission facilities and the need for additional water withdrawal facilities. The Plant Wansley site is not only more economical, but it will have minimal impacts on the environment and the surrounding community.

Through its new source review procedure, EPD has evaluated the Georgia Power proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 EMISSION CONTROL STRATEGY

2.1 Process Description

A basic combustion turbine (CT) combined-cycle (CC) system consists of a simple cycle CT, a heat recovery steam generator (HRSG), and a steam turbine. A simple cycle CT consists of a compressor, combustion chambers, and a power turbine. In a simple cycle CT, ambient air is drawn through an inlet manifold into a compressor. The air is compressed (pressurized) and fed into a combustor where it is mixed with fuel and ignited, raising the temperature of the mixture of air and combustion products. The compressed and heated gas mixture then flows through the turbine where the kinetic energy of the gas is utilized in shaft rotation (i.e., mechanical work).

Substantial energy remains in the exhaust gas which can be recovered, in this case, for expansion through a steam turbine to make additional electric power (combined-cycle). After expanding through the turbine, the exhaust gases from the simple cycle CT flow through a HRSG which, in this case, is supplementally fired by a duct burner. The duct burners increase the temperature of the turbine exhaust stream and this heat energy is transferred to water in the heat exchanger section of the HRSG. The water is converted from a liquid to superheated steam. The superheated steam is supplied to a steam generator, condensed to a liquid state, recovered, and pumped along with make-up water through the HRSG again. The turbine exhaust gases pass through the HRSG and are directed to a stack.

The power augmentation (PA) mode will be utilized on the Wansley combined-cycle units. Power augmentation is achieved by firing the duct burner at its highest design heat input and producing more steam from the HRSG than can be utilized in the steam turbine. This additional steam is routed to the combustion turbine where it is injected directly into the combustion chamber resulting in an increased mass flow through the machine. This increased mass flow produces about a 10% increase in output (MWs) from the combustion turbine. The PA mode of operation is primarily a peaking capability.

The Wansley combined-cycle facility is designed to be operated as a baseload facility. However, the actual annual load factor will depend on a number of factors including electricity demand and market price signals. The plant is designed such that the number of starts could range from as few as 20 to as many as 230 starts per year over the life of the units. Due to the relatively high cost for each startup and maintenance issues relative to multiple starts, the goal is to keep the number of starts to significantly less than 100 per year, with 65 to 70 per year being in the “normal” range.

2.2 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 (NSPSs). 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.

The BACT determination should, at a minimum, meet two core requirements.¹ The first core requirement is that the determination follow a "top-down" approach. The second core requirement is that the selection of a particular control system as BACT must be justified in terms of the statutory criteria and supported by the record, and must explain the basis for the rejection of other more stringent candidate control systems.

¹ The discussion of the core requirements is taken from the Preamble to the Proposed NSR Reform, 61 FR38272.

EPD's procedures for performing top down BACT analysis are set forth in EPA's Draft New Source Review Workshop Manual (Manual), dated October 1990. One critical step in the BACT analysis is to determine if a control option is technically feasible.² If a control is determined to be infeasible, it is eliminated from further consideration. The Manual applies several criteria for determining technical feasibility. The first is straightforward. If the control has been installed and operated by the type of source under review, it is demonstrated and technically feasible.

For controls not demonstrated using this straightforward approach, the Manual applies a more complex approach that involves two concepts for determining technical feasibility: availability and applicability. A technology is considered available if it can be obtained through commercial channels. An available control is applicable if it can be reasonably installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

The Manual provides some guidance for determining availability. For example, a control is generally considered available if it has reached the licensing and permitting stages of development. However, the Manual further provides that a source would not be required to experience extended time delays or resource penalties to allow research to be conducted on new technologies. In addition, the applicant is not expected to experience extended trials learning how to apply a technology on a dissimilar source type. Consequently, technologies in the pilot scale testing stages of development are not considered available for BACT.

In addition, as mentioned before, the Manual also requires available technologies to be applicable to the source type under consideration before a control is considered technically feasible. For example, deployment of the control technology on the existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility. However, even in this instance, the Manual would allow an applicant to make a demonstration to the contrary. For example, the applicant could show that unresolved technical difficulties with applying a control to the source under consideration (e.g., size of the unit, location of the proposed site and operating problems related to the specific circumstances of the source) make a control technical infeasible.

The following paragraphs of this section address each air pollutant emitted by the proposed project in amounts greater than the PSD significance thresholds, and the proposed method of its control to establish the limitations which represent BACT.

2.3 Oxides of Nitrogen

NO_x emissions are evaluated from the CT and the duct burner in the HRSG. NO_x is formed three different ways in CTs. The principal mechanism of NO_x formation from CTs firing gas is thermal NO_x. Thermal NO_x arises from the thermal dissociation and subsequent reaction of nitrogen (N₂) and oxygen (O₂) molecules in the combustion air. Most thermal NO_x is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce a peak temperature. A second mechanism which produces NO_x is termed prompt NO_x. Prompt NO_x forms within the combustion flame and is usually negligible when compared to the amount of thermal NO_x formed. The third NO_x formation mechanism is termed fuel NO_x, and fuel NO_x stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen.

² Discussion on technical feasibility is taken from the PSD Final Determination for AES Londonderry, L.L. C., Rockingham County, New Hampshire. The PSD Final Determination was written by the U.S. EPA Region I, Air Permits Program.

Suppressing thermal NOx formation in CTs has been commercially demonstrated several ways through adjustments to the air-fuel ratio, combustion air temperature, and combustion zone cooling. Adjustments of these parameters can be accomplished through water injection or dry control technology. In some cases combustor design does not adequately lower NOx emissions and post-combustion control must be considered.

In reviewing the BACT alternatives to control emissions of NOx from the CT/HRSG system, Georgia Power considered post-combustion control technology (selective catalytic reduction and catalytic absorption), dry and wet control technology, and catalytic combustion for NOx suppression.

The least stringent level evaluated for the CT and HRSG are specified by New Source Performance Standards (NSPSs) as illustrated in the following table:

Unit	NOx Emission Rate	Source of Emission Rate
Simple Cycle CT	108 ppmvd, 15% oxygen	40 CFR 60, Subpart GG [40 CFR 60.332(a)1.]
Duct Burner	1.6 lb/MWh, gross energy output on a 30-day rolling average for NOx	40 CFR 60, Subpart Da [40 CFR 60.44a(a)1.]

NSPS GG is an applicable requirement because the proposed turbines are constructed after October 3, 1977 and have a heat input equal to or greater than 10 MMBtu/hr. The duct burners are subject to NSPS Da because they each meet the definition of “electric utility steam generating unit;” are capable of combusting more than 250 MMBtu/hr heat input of fossil fuel; and they are constructed after September 18, 1978.

Georgia Power considered combustion modification with post combustion control as the basis for BACT. The requirement for PA operation was factored into all of the emission rates presented. For the economic analyses, weighted average emission rates were used based on operation for 1000 hours per year in the worst case emission rate mode (i.e., PA) and operation for the remaining 7,760 hours per year in the highest emission rate mode without PA.

The individual NOx BACT combinations considered are noted below:

- Base Case: DLN Technology
- Option 1: DLN + Wet Control Technology
- Option 2: DLN + Selective Catalytic Reduction (SCR)
- Option 3: DLN + Catalytic Absorption
- Option 4: DLN + Catalytic Combustion

Base Option - DLN Technology

Gas turbine combustors were originally designed to operate with a near stoichiometric mix of fuel and air in the primary combustion zone.³ In a conventional combustor, the fuel and air are introduced directly into the

³Discussion about dry and wet control technologies is taken from the Gas Research Institute Web page Entitled “Combustion Turbine Design, Operation , and Control.”

combustion zone and fuel-air mixing and combustion take place simultaneously. Dry Low NO_x (DLN) technologies are based upon reducing the flame turbulence and intensity, enhancing the fuel/air mixing, and establishing fuel-lean zones within the combustor. Current DLN technologies do exist for CTs and for duct burners, and in a lean premixed combustor design, the air and fuel are premixed at very lean air-to-fuel ratios prior to introduction in the combustion zone. The premixing minimizes local fuel-rich zones. In addition, the excess air in the lean mixture acts as a heat sink and lowers combustion temperatures, which can effectively reduce the formation of thermal NO_x. As NO_x emissions from DLN technology in CTs go as low as 9 ppmvd, at 15% oxygen, some manufacturers have experienced problems with combustion vibration (dynamic pressure oscillations) and premature combustor deterioration. With these facts in mind, the use of DLN technology in the proposed CT/HRSG system is technically feasible and is achievable in practice.

In order to evaluate BACT for this base option, EPD reviewed data gathered by EPA and the Texas Natural Resource Conservation Commission (TNRCC). The TNRCC issued a draft BACT review for natural gas fired turbines in late 1999, based on a nation wide survey, and their findings can be found at http://www.tnrcc.state.tx.us/air/nsr_permits/guidedoc.htm. Based on EPD's review, NO_x BACT levels for DLN Technology only ranged from 9 to 15 ppmvd, at 15% oxygen. Georgia Power has proposed a BACT level for their base option at 11.2 ppmvd, at 15% oxygen which is well below the NSPS limit of 75 ppmvd @ 15% oxygen.

EPD agrees with this NO_x emissions level being used as the base case option. No economic or environmental analyses are performed since this is the base case option.

Option 1 - DLN and Wet Control Technology

As noted earlier, the use of DLN technology is technically feasible and is achievable in practice. The principal requirements in using wet injection for NO_x reduction are to inject sufficient water or steam at the proper location in the flame envelope within the combustor, and with appropriate dispersion, to reduce the peak flame temperature without degrading the combustion efficiency. Energy extracted from combustion to vaporize the water causes additional temperature reduction. The major factor affecting NO_x reduction is the water-to-fuel ratio. The NO_x reduction achievable for a particular unit is directly related to the amount of water which can be injected before serious impacts on combustor performance occur. The impacts include flame outs, reduced thermal efficiency, large increases in CO and hydrocarbon emissions, and pressure pulsations which result in significantly reduced combustor reliability. In addition, fuel consumption can increase as well as the maintenance costs. The highest water to fuel ratio sustainable will vary depending on the tradeoff between NO_x emissions and CO and hydrocarbon emissions, and combustor design characteristics. Wet injection is applicable to gas or liquid fuels and is technically feasible for the proposed CTs.

Requirements for wet injection include a large water supply, on the order of the fuel rate, and water purification (to boiler feedwater quality) to prevent corrosion. The added water increases the mass flow through the turbine, increasing electrical output. The fuel to electrical-energy conversion efficiency may decrease if water is used instead of steam. Water quality must be maintained consistently through the use of demineralized water in order to assure turbine durability.

The particular DLN combustor that is proposed for this project can accept wet injection (steam) only during episodes of power augmentation. The turbine vendor anticipates a NO_x emission rate from wet injection to be higher than with only DLN technology. With this in mind, option 1 is not considered technically feasible/achieved in practice and will not be considered any further in the NO_x BACT evaluation.

Option 2 - DLN Technology with SCR Post Combustion Control

As noted in option 1, the use of DLN technology in the CT/HRSG with supplemental duct burner firing is technically feasible and is achievable in practice. SCR reduces NO_x emissions by injecting ammonia (NH₃) into the CT exhaust gas stream upstream of a catalyst. NO_x, NH₃, and O₂ react on the surface of the catalyst to form N₂ and H₂O. In order for the SCR system to operate properly, the CT exhaust gas stream must contain a minimum amount of O₂ and be within a particular temperature range (600-800°F). The appropriate temperature range is dictated by the type of catalyst, and if the exhaust temperature exceeds the recommended catalyst temperature, NO_x and unreacted NH₃ pass through the catalyst. The proposed CT/HRSG systems will operate with an exhaust gas temperature of approximately (600-750°F). SCR control technology is most commonly used in CTs that operate in cogeneration or combined cycle where the catalyst is installed within the HRSG, where the heat recovery process reduces exhaust gas temperatures to the proper operating range for the catalyst.

The use of SCR on the proposed CT/HRSG systems is technically feasible and achievable in practice.

Georgia Power proposed a NO_x BACT limit for this option to be 3.5 ppmvd @ 15% oxygen at the combined stack from the CT and duct burner in the HRSG. This proposed NO_x BACT limit is much more stringent than the NSPS limits noted earlier in this discussion.

The environmental analysis for this option focused mainly on the fact that anhydrous ammonia would be used as a reagent in the SCR process and the collateral concerns that would be conceived. Collateral environmental concerns evaluated were the presence of ammonia emissions; the formation of fine particulates; and the safety hazards associated with the transport, handling and storage of ammonia.

During the review of this option, the issue of NH₃ slip from the SCR, was among the difficult to address. The NH₃ emissions are recognized as an environmental disadvantage, even though their presence allows additional control of NO_x. The amount of NH₃ slip at any facility will theoretically begin at near zero and increase over the life of the catalyst while NO_x emissions control remains constant. At times, emissions of ammonia will be offset at a 1-to-1 ratio with NO_x reductions. The contractual ammonia slip guarantee is 10 ppmvd @ 15% oxygen. This is what the slip would be at the end of the five-year catalyst guarantee. An ammonia slip of 10 ppmv at 15% oxygen is approximately 23.71 lb/hr. (Note: This value is derived in Appendix C.) Eight CT/DB's would result in approximately 226.48 lb/hr of ammonia emissions, at the maximum expected ammonia slip after five years. This expected worst-case ammonia emissions rate is well within the emission rates allowed by the Georgia Air Toxics Guideline, namely 6,843 lb/hr (annual average) and 9,954 lb/hr (15-min average). Refer to Appendix C for more information on this analysis.

The presence of unreacted ammonia in the turbine exhaust could possibly react with NO_x, sulfate or oxygen species to form fine particles of ammonium nitrate and/or ammonium sulfate which would primarily exist as fine particulate emissions (PM_{2.5}). PSD regulations do not provide a mechanism to analyze the impact of PM_{2.5} at this time.

Option 2 requires that the proposed plant configuration include ammonia storage and handling capabilities. This project would be subject to risk management plans under Section 112(r) of the 1990 Clean Air Act Amendments (40 CFR 68) if they store more than 10,000 pounds of anhydrous ammonia in one tank at any one time at the facility. The amount of ammonia that will be used by the project will depend on the load factor of the unit and how much PA takes place. Since both of these factors are based on future economic conditions, it is difficult to predict exactly how much ammonia will be used. Georgia Power estimated that during PA mode the maximum ammonia consumption would be 62 lb/hr and during the non-PA mode the maximum ammonia consumption

would be 50 lb/hr. These values are for each SCR system. This equates to approximately 1,800 tons (over 600 million gallons) of ammonia used per year for the eight proposed CT/HRSG trains. This PSD preliminary determination asserts that Georgia Power would achieve compliance with the Part 68 standard if this option was implemented as BACT.

The use of SCR also requires that the disposal of the catalyst may be a hazardous waste issue. The life of the original catalyst has been guaranteed for five years with the first replacement and disposal provided as part of the HRSG contract. It is anticipated that part of any contract for supplying new catalyst will have the catalyst supplier take responsibility for disposal of the old catalyst.

These environmental concerns must be weighed with the fact that this plant is located in a county whose air quality is considered to contribute to the metro Atlanta's ozone nonattainment status.

Georgia Power estimated a BACT cost effectiveness per CT/HRSG train to be approximately \$4,500 per ton of NO_x removed. EPD agrees with Georgia Power that this option is technically feasible, achievable in practice, cost effective, and should be considered as a NO_x BACT option even in light of the environmental concerns.

Option 3 - DLN Technology with Catalytic Absorption Post Combustion Control

As noted in options 1 and 2, the use of DLN technology in CT/HRSG with supplemental duct burner firing is technically feasible and achievable in practice. Catalytic absorption is a type of post-combustion control whereby the flue gas is exhausted over a catalyst system with an absorber coating to oxidize CO to CO₂ and NO to NO₂. The SCONOx™ system, developed by Goal Line Environmental Technologies, is a proprietary precious metal oxidation catalyst system with an absorber coating. In the SCONOx™ system, the NO₂ is removed from the catalyst by passing a dilute hydrogen reducing gas across its surface. This releases the NO₂ from the surface as N₂ and H₂O. The catalyst must be continuously regenerated.

ABB Environmental Systems (ABBES) is the world wide exclusive licensee for the application of SCONOx™ to combined-cycle gas turbines engines greater than 100 MW in generation. ABBES noted in a press release dated December 1, 1999, that ABBES has completed a scale up commercialization of the SCONOx™ system and is now offering the technology with performance guarantees to all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size or OEM. EPD submitted a letter to ABBES on February 16, 2000 requesting their input on the technical feasibility and cost effectiveness of SCONOx™ on the proposed modification. ABBES has not responded to this inquiry as of the date of this Preliminary Determination.

SCONOx™ technology has been applied in only two retrofit situations as reported by Georgia Power. Both installations are at 30 MW combined-cycle power plants (i.e., 30 MW GE LM2500 gas CT) , and these installations currently utilize a scrubber to remove trace sulfur compounds from the natural gas before it is combusted in the CT in order to minimize sulfur blinding. With these issues in mind, Georgia Power estimated that the cost of implementing catalytic absorption to control NO_x emissions to result in a cost effectiveness of approximately \$26,307 per ton of NO_x removed.

After review of information from the TNRCC, and EPA, EPD is unable to support setting BACT based on this emerging technology. Although the EPD recognizes this technology as extremely promising, it is our position that SCONOx™ has not been sufficiently demonstrated over the broad range of combined-cycle natural gas fired turbines to be considered a proven technology for the purpose of establishing its use as BACT in this case. However, the EPD will continue to monitor the application of SCONOx™ and its impact on future natural gas fired turbine BACT.

Based on these findings, option 3 is not considered any further in this NOx BACT evaluation.

Option 4 - DLN Technology and Catalytic Combustion

As noted in options 1,2, and 3 the use of DLN technology in the CT/HRSG with supplemental duct burner firing is technically feasible and is achievable in practice. Catalytic combustion is a form of flameless combustion, as the fuel and air react on a catalytic surface. XONON™ is a catalytic combustion system, developed by Catalytica Combustion Systems, Inc. (CCSI), that is purported to achieve 2.5 ppm NOx with emissions of both CO and VOC less than 6 ppm. The XONON™ combustion system replaces the conventional combustor and, according to Catalytica Combustion Systems, Inc., has no impact on the gas turbine performance.

A commercial-ready™ combustion system is installed on a 1.5 MW Kawasaki natural gas fired combustion turbine at Silicon Valley Power in Santa Clara, California. This turbine has been in continuous operation since July 1999 and has resulted in an average NOx emission rate at full load to less than 2 ppmvd, corrected to 15% oxygen. In a press release dated December 15, 1999, the XONON™ combustion system has been specified as the preferred emissions control system with the GE 7FA turbines that have been ordered for the proposed Pastoria Energy Facility, a project proposed by affiliates of ENRON North American. (Note: ENRON acquired a 15% interest in Catalytica Combustion Systems in December 1997). No decisions have been made as to the make, model, and turbine sizes. As of this review, GE is not yet offering the XONON™ system as an option on its E-class (nominally 80 MW) and F-class (170 MW) machines.

After review of information from Catalytica, TNRCC, and EPA, EPD is unable to support setting BACT based on this emerging technology because it is not yet commercially available. However, the EPD will continue to monitor the availability and application of XONON and its impact on future natural gas fired turbine BACT.

Based on these findings, option 4 is not considered any further in this NOx BACT evaluation.

Conclusion

EPD has determined that the proposal to use a DLN combustor in the turbine and a DLN burner in the duct burner with SCR as post-combustion control for the turbine and duct burner while burning natural gas to meet the requirements of BACT. The GE DLN combustor used will be a two-stage lean premixed combustor design for use with natural gas. The NOx BACT emission limits are set at 3.5 ppmvd (corrected to 15% oxygen) at the stack exit for each CT/HRSG system. The averaging period is on a rolling 30-days.

Catalytic absorption was not determined to be achievable in practice because it has not been sufficiently demonstrated over the broad range of combined-cycle natural gas fired turbines to be considered a proven technology for the purpose of establishing its use as a BACT in this case. Also, in EPD's opinion, catalytic absorption is not yet a BACT cost effective choice. Catalytic combustion was not determined to be achievable in practice because it is not yet commercially available.

NOx emissions from each combined-cycle block will be capped to not equal or exceed 260 tons (i.e., 1,040.7 tons of NOx from the four blocks combined divided by four). No limit is required on heat input since the BACT analysis was at 8,760 hours per year.

2.4 Sulfur Dioxide

Sulfur dioxide (SO₂) is emitted as a result of the oxidation of the sulfur in the fuel. The proposed CT/HRSG systems will be fueled with natural gas only. Natural gas does contain a small amount of sulfur, including sulfides and sulfur-containing mercaptan, which is added to natural gas to permit leak detection. Therefore, a small amount of SO₂ is produced in the combustion of natural gas.

The least stringent levels evaluated for the CT/HRSG system are specified by New Source Performance Standards (NSPSs) as illustrated in the following table:

Unit	SO ₂ Emission Rate	Source of Emission Rate
Simple Cycle CT	150 ppm or a maximum fuel content of 0.8 weight percent	40 CFR 60, Subpart GG [40 CFR 60.333]
Duct Burner	0.80 lb/MMBtu plus 90% reduction OR 0.20 lb/MMBtu with no reduction	40 CFR 60, Subpart Da [40 CFR 60.43a(b)]

The BACT alternative that Georgia Power considered was the exclusive use of natural gas in the CT/HRSG systems. They are assuming that the natural gas to be used will have very low sulfur content (i.e., ~0.00068 weight percent). The typical weight percent sulfur content of very low sulfur distillate fuel oil is less than 0.05. The use of natural gas in the CT/HRSG system is technically feasible.

The use of low and very-low sulfur fuels have established records of compliance when used in combustion equipment such as CTs and burners. Therefore, the very low SO₂ emission rate that results from the use of natural gas represents the top level of SO₂ emissions control for a CT. The expected SO₂ emission rate, without controls, from the duct burner are 0.0006 lb/MMBtu, which is well below the least stringent BACT emission rate of 0.20 lb/MMBtu (i.e., NSPS Da).

Given this extremely low emission rate it is proposed that the use of natural gas continue to be considered as the SO₂ BACT when firing natural gas. There are no fuels available with a lower sulfur content and given the large exhaust gas volume from the combustion turbines and extremely low SO₂ concentrations, any attempt to further reduce SO₂ emissions would be practically impossible. The use of natural gas over other types of fuels is considered cost-effective and no cost analysis was performed for this BACT option.

The Division has determined that Georgia Power's proposal to only fire natural gas in the CT/HRSG systems meets the requirements of BACT for SO₂.

2.5 Carbon Monoxide and Volatile Organic Compounds

As noted earlier, gas turbine combustors were originally designed to operate with a near stoichiometric mix of fuel and air in the primary combustion zone. Reduction in NO_x emissions, through combustion modification, included reduced combustor residence time and lean pre-mix conditions. Shortening the residence time of the combustion products at high temperatures may result in increased carbon monoxide (CO) and hydrocarbons (HC) emissions if no other changes are made in the combustor. In order to minimize increases in CO and HC emissions,

combustors with reduced residence time also incorporate design changes in the air distribution ports to promote turbulence, which improves air/fuel mixing and reduces the time required for the combustion process to be completed. According to the Gas Research Institute, the differences between reduced residence time combustors and standard combustors are the placement of the air ports, the design of the circulation flow patterns in the combustor, and a shorter combustor length.

Care must be taken when incorporating design changes to reduce both NO_x and CO emissions. CO emission combustion modifications can possibly increase NO_x emissions and vice versa. A balance between these air pollutants must be achieved in order for combustion modification to be useful.

CO and VOC BACT Evaluation

NSPS Subpart Da and GG do not specify CO or VOC emission limits, and no other applicable federal requirements exist that provide the least stringent level for CO and VOC emissions.

Georgia Power reviewed two BACT alternatives; namely catalytic oxidation post combustion control, and efficient combustion which is a direct result of the design and operation of the turbine.

Georgia Power considered combustion modification with post combustion control as the basis for BACT. The individual BACT combinations are noted below:

Base Case: Proper Combustion Design/Operation or Good Combustion Practice (GCP) Option 1: GCP + Catalytic Absorption Option 2: GCP + Selective Catalytic Reduction (SCR) Option 3: GCP + Catalytic Oxidation

Base Option - Good Combustion Practice (GCP)

EPD considers GCP as technically feasible and achievable in practice for the turbine and duct burners in question. In order to evaluate BACT for this base option, EPD reviewed data gathered by EPA and the Texas Natural Resource Conversation Commission (TNRCC). Based on EPD's review, CO BACT levels for combustor modifications for turbines at combined-cycle natural gas fired systems rated at 100 MW or greater ranged from 9 to 25 ppm. Georgia Power proposed a baseline CO BACT at the stack exhaust of approximately 29.5 ppm and a VOC BACT at the stack exhaust of approximately 6.2 ppmvd (as methane).

No economic or environmental analyses are performed since this is the base case option.

Option 1 - GCP with Catalytic Absorption Post Combustion Control

Catalytic absorption for CO and VOC reduction works in much the same way that it does for NO_x reduction. The flue gas is exhausted over a catalyst system with an absorber coating to oxidize CO to CO₂ and NO to NO₂. EPD considers catalytic absorption as technically feasible; however, not yet achieved in practice.

EPD submitted a letter to ABBES on February 16, 2000 requesting their input on the technical feasibility and cost effectiveness of SCONOX™ for control of CO and hydrocarbon emissions on the proposed modification. ABBES has not responded to this inquiry as of the date of this Preliminary Determination. After review of information from the TNRCC, and EPA, EPD is unable to support setting BACT based on this emerging technology. Although the EPD recognizes this technology as extremely promising, it is our position that SCONOX™ has not

been sufficiently demonstrated over the broad range of combined-cycle natural gas fired turbines to be considered a proven technology for the purpose of establishing its use as BACT in this case. However, the EPD will continue to monitor the application of SCONOX™ and its impact on future natural gas fired turbine BACT.

Based on these findings, option 1 is not considered any further in this CO BACT evaluation.

Option 2 - GCP and SCR Post Combustion Control

Georgia Power determined that SCR post combustion control does not lower CO or VOC emissions. In fact, the turbine operator must take care to not let NOx emissions get so low that the CO emissions increase. Option 2 is not considered any further in this CO BACT evaluation.

Option 3 - GCP and Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of CO and hydrocarbons. A catalytic oxidation system is a passive reactor which consists of a honeycomb grid of metal panels, typically coated with a platinum or rhodium. The catalyst grid is placed in the engine exhaust where the optimum reaction temperature can be maintained (450⁰F - 1200⁰F). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to lower the activation energy necessary for complete oxidation of these incomplete combustion byproducts to carbon dioxide. The active component of most catalytic oxidation systems is platinum metal, which has been applied over a metal or ceramic substrate. As with SCR, minimization of pressure drop is a major design criteria; therefore, honeycomb catalyst designs are common.⁴ The primary limitation that may preclude the use of catalytic oxidation is frequent, wide load variations, which will reduce catalyst efficiency and may cause thermal shock degradation of the catalyst. EPD believes that catalytic oxidation is technically feasible and achievable in practice for the proposed modification.

Catalytic oxidation has gained acceptance in natural gas-fired combustion turbine applications, primarily combined-cycle systems, in CO nonattainment areas of the country (i.e., LAER situations). In order to evaluate BACT for this base option, EPD reviewed data gathered by EPA and the TNRCC. Based on EPD's review, CO BACT levels for catalytic oxidation on combined-cycle systems rated at 100 MW or greater and firing natural gas range from negligible to 10 ppm. There is the possibility that CO emissions can be reduced to approximately 3 ppm from turbines rated at greater than 100 MW with catalytic oxidation.

Georgia Power estimated that the presence of a CO catalyst would decrease the CO and VOC mass emission rate by approximately 50% and 25%, respectively.

There has been much discussion about catalytic oxidation technology. The Alabama Department of Environmental Management (ADEM) recently issued a PSD Preliminary Determination for an identical Georgia Power site near Smiths, Alabama. The plant is referred to as Goat Rock Combined Cycle Plant. ADEM did not propose the use of catalytic oxidation as BACT; however, no reason was provided other than GCP has routinely been defined as CO BACT.

Based on discussions with utility permit writers in the Northeast, EPD has found that cost effectiveness values of \$2,000/ton and higher of CO removed have been deemed "not cost effective." Georgia Power estimated a cost effectiveness of \$3,249/ton of CO removed resulting in a CO BACT of 10 ppm. EPD does not agree with this

⁴ Discussion about catalytic oxidation is taken from the Gas Research Institute Web page Entitled "Combustion Turbine Design, Operation, and Control."

cost effectiveness because they assumed an uncontrolled CO emission rate of 94 lb/hr, instead of 138 lb/hr as shown in their CO BACT emission limit request. With this revision, EPD estimated a CO BACT cost effectiveness of \$1,634 per ton of CO removed.

Georgia Power did not consider any VOC reduction capability from catalytic oxidation. Hence, they did not propose a VOC BACT cost effectiveness; nor did they propose a combined CO/VOC BACT cost effectiveness.

EPD is not inclined to establish catalytic oxidation as BACT in this case because no CT/HRSG train recently permitted in EPA Region IV has been required to include catalytic oxidation as BACT.

Conclusions

The Division has determined that Georgia Power's proposal to use proper combustion design meets the requirements of BACT. Neither 40 CFR 60, Subpart GG or State air quality rules includes specific standards for CO or VOC from CTs. CO and VOC emissions have to be balanced against NOx emissions. At the proposed BACT emissions levels for NOx, the CO and VOC emissions will be limited to the following at the combined or stack exit:

CO = 0.061 lb/MMBtu, 29.5 ppm@15% oxygen, 138.7 lb/hr
 VOC = 0.008 lb/MMBtu, 6.2 ppmvd (as methane) @ 15% oxygen, 17.0 lb/hr

Stack testing of the turbines will be required to determine compliance with the CO emission limits.

2.6 Particulate Matter

Emissions of particulate matter (PM) and particulate matter less than 10 microns in diameter (PM₁₀) from a CT results from inert solids contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles, and mineral matter in the water injected into the turbine for NOx control. All of the particulate matter emitted from the proposed CT is believed to be less than 10 micrometers in diameter. In addition, the proposed modification will not use water injection for NOx control.

Existing PM/PM10 control technologies such as cyclones, wet scrubbers, electrostatic precipitators, and fabric filters were considered by Georgia Power. In addition, they considered proper combustor design and the use of low ash fuels. Minimizing PM and PM10 emissions from the CT/HRSG system typically occur through maintaining high combustion efficiencies and by burning low ash fuels.

The least stringent level evaluated for the CT/HRSG system are illustrated in the following table:

Unit	PM Emission Rate	Source of Emission Rate
Simple Cycle CT	9 lb/hr, 0.0056 lb/MMBtu at 65 ⁰ F and at base load	No NSPS applicable. Data from General Electric
Duct Burner	0.013 lb/MMBtu Opacity limited to 20%	40 CFR 60, Subpart Da [40 CFR 60.42a(a) and (b)]

PM/PM10 BACT Evaluation

Georgia Power considered combustion design, the use of low ash fuels, and post combustion control as the basis for the BACT evaluation. Please note that PM post combustion control devices such as settling chambers, fabric filters, electrostatic precipitation, cyclones, and wet scrubbers were not considered technically feasible. As such they were not included in the BACT evaluation.

The individual PM/PM10 BACT combinations considered are noted below:

- Combustion design/natural gas
- Combustion design/natural gas plus SCR

Natural gas is considered to be a clean burning fuel, and Georgia Power has proposed to fire the CT/HRSG system with only natural gas. EPD agrees with Georgia Power’s findings that the installation of a PM control device on a turbine firing clean fuels is considered to be impractical, in part because CT’s generate an exhaust stream with a low concentration (i.e., <0.1 gr/acf) and small particle diameters. With these facts in mind, it is almost impossible for a vendor to guarantee a concentration lower than the proposed baseline BACT.

Natural gas contains essentially no inert solids (ash). A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on gas- -fired CTs to control PM and PM₁₀ emissions as shown in Georgia Power’s control technology review.

Given the high combustion efficiency of the turbines and the firing of clean fuels, the PM and PM₁₀ emissions should be very low. Georgia Power proposed a PM BACT emission limit of 0.010 lb/MMBtu when firing natural gas. In addition, they propose the use of clean fuel (natural gas) as BACT for PM and PM₁₀. Note: In this case PM emissions are equivalent to PM₁₀ emissions.

The use of clean burning fuels, such as natural gas, was determined to meet the requirements of BACT by the EPD for Georgia Power Jackson County Combustion Turbine Project and the Heard County Power Project (Dynergy). With all of this in mind, the Division has determined that the burning of clean fuels in the CTs meets the requirements of BACT. PM emissions, and thus PM₁₀ emissions, will be limited to the BACT PM limits proposed by the company.

2.7 Summary

Emission Standards: Part 2 of this Preliminary Determination has illustrated the analysis performed to assess the appropriate BACT for the proposed CT/HRSG systems. The results are summarized in the following table:

Pollutant	BACT - CT Exit	BACT - DB Exit	Combined or Stack Exit (Permit Limit)	Averaging Period
NOx	DLN Combustor	Low-NOx Burner	Controlled by SCR 3.5 ppmvd @ 15% O ₂	30-day rolling average
CO	Efficient Combustion	Efficient Combustion 0.216 lb/MMBtu	0.066 lb/MMBtu	Based on applicable test method.

Pollutant	BACT - CT Exit	BACT - DB Exit	Combined or Stack Exit (Permit Limit)	Averaging Period
	0.034 lb/MMBtu 66.2 lb/hr	72.5 lb/hr		
VOC	Efficient Combustion 0.002 lb/MMBtu 3.9 lb/hr	Efficient Combustion 0.039 lb/MMBtu 13.1 lb/hr	0.008 lb/MMBtu as methane	Based on applicable test method.
SO ₂	Fire natural gas only	Fire natural gas only 0.0006 lb/MMBtu	Fire natural gas only	N/A
PM/PM ₁₀	Fire natural gas only Efficient Combustion 0.009 lb/MMBtu 17.6 lb/hr 10% opacity	Fire natural gas only Efficient Combustion 0.007 lb/MMBtu 2.4 lb/hr 10% opacity	0.010 lb/MMBtu 10% opacity	Based on applicable test method. 6-minute average

3.0 APPLICABLE RULES AND REGULATIONS

Now that the PSD BACT standards have been defined, the next step is to review the remaining applicable requirements. This step will aid in citing the appropriate legal authority for each requirement in the Title V permit. This analysis will show that the PSD BACT standards represent the most stringent limit.

3.1 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

Applicability: NSPS GG is an applicable requirement for each CT because each CT has a nameplate capacity greater than 10 MMBtu/hr, and they are constructed after October 3, 1977.

Emission Standard: The allowable NO_x emission rate is specified by the following formula [40 CFR 60.332(a)(1)] because each CT has a heat input rating greater than 100 MMBtu/hr:

$$STD = 0.0075 (14.4/Y) + F$$

where: STD = allowable NO_x emissions (% volume @ 15% O₂, dry)
 Y = heat rate in kilojoules per watt hour
 F = fuel bound nitrogen allowance

Note: The application reported a value of 10.00 kJ/W-hr for “Y” and 0 for “F” yielding an allowable NO_x emission rate of 108 ppmvd corrected to 15% oxygen, dry basis. However, actual values of Y and F may vary depending on both the fuel and the actual operation of the turbine.

The allowable fuel sulfur content is 0.8 percent by weight in accordance with 40 CFR 60.333(b).

Compliance Demonstration: Compliance is demonstrated with an initial performance test using Method 20 and thereafter by monitoring the water-to-fuel injection ratio and reporting excess emissions based on that ratio. Where units do not employ water injection, EPA has asked that sources propose an alternative method and, where requested, has approved use of NO_x CEMS to identify and report excess emissions.⁵

3.2 40 CFR 60, Subpart Da - Standard of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Applicability: NSPS Da is an applicable requirement for each duct burner because they each have a heat input rating greater than 250 MMBtu/hr and they are constructed after September 18, 1978.

Emission Standard: This NSPS specifies an emission standard for PM, SO₂, and NO_x from each duct burner as noted in the following table:

Pollutant	Standard	Legal Authority

⁵ Taken from page 3 of letter to Susan Jenkins (EPD) from Charles Huling (Georgia Power) dated April 25, 2000, found in Appendix B.

Pollutant	Standard	Legal Authority
PM	0.03 lb/MMBtu	40 CFR 60.42a(a)(1)
Opacity	20% except for one six-minute period per hour of not more than 27 percent.	40 CFR 60.42a(b)
SO ₂	0.20 lb/MMBtu on a 30-day rolling average	40 CFR 60.43a(b)(2)
NO _x	1.6 lb/MW-hr, gross energy output, based on a 30-day rolling average	40 CFR 60.44a(d)(1)

Compliance Demonstration: Note that the emissions from the CT that are exhausted into the HRSG are not subject to NSPS Da. NSPS Da requires the installation of a NO_x CEM and a volumetric flow monitor in the stack, and to use those data to calculate pounds of NO_x. According to the regulation, that value is then divided by the “average hourly gross heat rate” measured by a wattmeter to determine pounds per MW-hour.⁶ In order to determine NO_x emissions from the duct burners in the HRSG, the regulation calls for subtraction of the CT’s NO_x emissions, as determined when the CT is performance tested under Subpart GG, from the total NO_x emissions measured in the stack using the equations in Method 19.

3.3 Acid Rain Program

Applicability: The Acid Rain Regulations apply to the proposed CT/HRSG units because they each have a nameplate capacity greater than 25MW_e and they are to supply electricity for sale, whether wholesale or retail.

According to 40 CFR 72, the modification will be designated as a Phase II Acid Rain "New Affected Unit" on January 1, 2000 or 90 days after commencement of commercial activities, whichever comes later, but not after the date the modification declares itself commercial. Georgia Power submitted their Phase II Permit Application on November 17, 1999.

Emission Standard: No SO₂ allowances are allocated up front to this modification by the Acid Rain Regulations. As such, Georgia Power will need to acquire SO₂ allowances in amount equal to their annual SO₂ tonnage by January 30 to cover its emissions for the previous year. Annual SO₂ emissions could be as high as 52.6 tpy.

NO_x emissions are not limited by the Acid Rain Regulation since the units are not classified as coal-fired utility boilers.

3.4 40 CFR 63 Subpart B - Case-by Case MACT

40 CFR 63 Subpart B is referred to as “Case-by-Case MACT,” or in this narrative, as a 112(g) determination. Section 112 of the Clean Air Act as amended in 1990 requires that EPA issue emission standards for all major sources of 188 listed HAPs. Section 112(g) is intended to ensure that HAP emissions do not increase excessively if a facility is constructed or reconstructed before EPA issues a MACT standard for that particular category of sources or facilities. When 112(g) is triggered by a construction or modification project, EPA is required to make case-by-case MACT determinations, which ultimately be superseded by EPA when a final MACT standard is promulgated by EPA. Therefore, 112(g) is a transitional measure. Section 112(g) became effective in Georgia on June 30, 1998.

⁶ Taken from page 4 of the same reference in footnote 5.

EPD considered whether the exclusion offered to “electric utility steam generating units” applies in this case. Based on EPA’s Interpretative Rule published in the Federal Register on April 21, 2000 [65 FR 21363], the simple cycle turbine in a combined-cycle system is subject to 112(g) provided it also meets the definition of a major source under Part 63.⁷ The exclusion only applies to the emissions from the HRSGs and the steam generators.

HAPs are primarily the result of incomplete combustion . Low CO is an indication of very good combustion and therefore HAP emissions should also be low. According to EPA⁸, the following HAPs have been measured above the emission test method detection limits from gas-fired combustion turbines: acetaldehyde, acrolein, benzene, ethyl benzene, formaldehyde, naphthalene, PAH, toluene, and xylene. The concentrations of these HAPs are low with many concentrations being very close to the emission test methods detection limits. EPA has developed and is maintaining the Stationary Combustion Turbines Emissions Database. Georgia Power based individual HAP emissions on the highest emission factor available for purposes of verifying compliance with the Georgia Air Toxics Guideline. If these same emission factors are used to make a 112(g) applicability determination, the CT/HRSG trains would be a major source under Part 63. Thus, Georgia Power would have to comply with 40 CFR 63 Subpart B.

After review of information from EPA, EPD does not believe that each of the proposed combined-cycle blocks are a major source under Part 63. (Note: EPD believes that each combined-cycle block constitutes a new process or production unit under 112(g) and not all new combined-cycle blocks combined.) EPD recognizes that EPA’s development of their CT database, and the work of numerous other turbine and utility organizations, is extremely promising in generating credible HAP emissions data from gas-fired turbines. However, it is our position that the data does not indicate that the proposed facility would emit individual HAP emissions on the order of 10 tpy or higher or would emit total HAPs greater than 25 tpy. EPD will impose testing requirements on Georgia Power to determine the emissions of those HAPs whose potential emissions, using the highest available emissions factor, exceeds 10 tpy from the proposed turbines to make a 112(g) applicability determination. Those HAPs for which performance testing will be required are as follows: Benzene, Formaldehyde, Acetaldehyde, Naphthalene, polyaromatic hydrocarbons (PAHs), Toluene, and Xylene.

3.5 State Rules

Georgia Rule 391-3-1-.02(2)(b), (d), and (g) limits visible emissions, PM emissions (only from the duct burners), and fuel sulfur content. Georgia Rule (b) limits visible emissions to not equal or exceed forty (40) percent from the combined CT/HRSG stack. PSD BACT limits visible emissions to not equal or exceed ten (10) percent.

There is no applicable state regulation which limits PM emissions from the combustion turbine portion of the CT/HRSG system. Georgia Rule (d) limits PM emissions from the duct burner since it supplies indirect heat to the water in the HRSG heat exchanger. This superheated stream (turbine exhaust and duct burner heat energy) is blown over a heat exchanger which raise the temperature of water to superheated steam for use in the steam generator. The duct burner has a maximum heat input of 335 MMBtu/hr which equates to a Georgia Rule (d) allowable PM emission rate of 0.086 lb/MMBtu. The PSD BACT PM limit for the combined CT/HRSG stack is 0.01 lb/MMBtu.

⁷ A major source under Part 63 is one with potential individual and/or total hazardous air pollutants (HAPS) that equal or exceed 10 tpy and 25 tpy, respectively.

⁸ Summary Sheet entitled “Combustion Turbines MACT Standards Development” from the EPA TTN [UATW web page](#).

Georgia Rule (g) limits the fuel sulfur content of the natural gas consumed in the turbines and duct burners to not equal or exceed 3.0 weight percent. The SO₂ emission limit presented in Table 1 assumes a sulfur content of 0.001 weight percent sulfur.

With these facts in mind, the PSD BACT limits subsume the applicable state emission limits.

4.0 TESTING AND MONITORING REQUIREMENTS

Each CT/HRSG train is subject to BACT requirements for NO_x, CO, VOC, SO₂, PM/PM10 emissions and for visible emissions (opacity); and the Acid Rain Regulations for SO₂ emissions. The PSD BACT requirements subsume the requirements for PM emissions specified in Georgia Rule 391-3-1-.02(2)(e); the opacity requirement specified in Georgia Rule 391-3-1-.02(2)(b); the NO_x, SO₂, PM, and opacity requirements specified in NSPS Da; and the NO_x emissions and fuel sulfur content requirements in NSPS GG. These regulations present a number of pragmatic testing and monitoring issues for the proposed project. Appendix B of the Preliminary Determination includes documents from Georgia Power and the Southern Company which describes these issues in detail.

The proposed CT/HRSG systems are subject to several parallel sets of requirements. In this case results in testing and monitoring requirements are redundant and unnecessary as a practical matter, even though the requirements still legally apply to the source. In EPA’s Part 70 White Paper #2⁹,

“In cases where compliance with a single set of requirements effectively assures compliance with all requirements, compliance with all elements of each of the overlapping requirements may be unnecessary and could needlessly consume resources. . . .The streamlined monitoring, recordkeeping, and reporting requirements would generally be those associated with the most stringent emissions limit, providing they would assure compliance to the same extent as any subsumed monitoring. Thus, monitoring, recordkeeping, or reporting to determine compliance with subsumed limits would not be required where the source implements the streamlined approach.”

In addition, the general provisions of NSPS provides avenues to obtain permission to use alternative testing and monitoring protocols, and in some cases, to waive testing requirements, when justified.

○ Testing Requirements

The table below illustrates the individual applicable testing requirements for the proposed project:

Pollutant	Turbine NSPS GG	Duct Burner NSPS Da	Stack Acid Rain
NO _x	Method 20 is performed at four different load points.	Method 19 is performed only for the duct burner.	No testing required
SO ₂	Method 20 is performed at four different load points OR	Method 19 (Note: In this case there is no applicable NSPS Da emission limit since natural gas will be used exclusively.)	No testing required.

⁹White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program, EPA, Office of Air Quality Planning and Standards, March 5, 1996.

Pollutant	Turbine NSPS GG	Duct Burner NSPS Da	Stack Acid Rain
	Choose between several ASTM standards.		
Opacity	No testing required.	Method 9 (Note: In this case there is no applicable NSPS Da opacity limit since natural gas will be used exclusively.)	No testing required.
CO	No testing required.	No testing required.	No testing required.
VOC	No testing required.	No testing required.	No testing required.
PM/PM10	No testing required.	No testing required.	No testing required.
HAPs	No testing required.	No testing required.	No testing required.

EPD proposes the following performance testing requirements based on EPD’s assessment of the overlapping testing requirements and Georgia Power’s request for Part 70 streamlining:

1. Georgia Power has requested that the testing requirements for NSPS GG be waived since the BACT limit for NO_x is much more stringent than under NSPS GG (Refer to Item 13 Appendix B). The permit reflects the EPD’s agreement with the request upon concurrence by the U.S. EPA. EPD proposes an identical testing protocol to that done by Georgia Power at Plant Robins, namely to conduct a NO_x emissions performance test on one combined CT/HRSG stack at four load points, as defined in 40 CFR 60.335.
2. The permit includes a performance test (initial 30 day period) on each combined CT/HRSG stack for NO_x emissions while burning natural gas, at base load, to verify compliance with the NO_x BACT emission standard.
3. SO₂ emissions will not be verified through performance testing since the BACT for SO₂ is the use of natural gas only.
4. CO emissions will be verified through conducting performance tests on two stacks at base load and at 75 percent load.
5. Performance tests will be required on two stacks for VOC and PM at base load. Performance tests on two stacks for visible emissions will also be required. The performance tests for CO, PM, and visible emissions shall be conducted concurrently.
6. A review of the EPA natural-gas fired combustion turbine HAP emission source test results reveals that emissions for each individual HAP can vary on a mass per heat input basis (i.e., lb/MMBtu) by several orders of magnitude. Due to the variability in the range of lb/MMBtu HAP emission factors for NG fired CTs, a range of emission factors and potential HAP emission rates were presented, by Georgia Power, for this project. As noted earlier, the low end point was used to establish the expected potential HAP emission rate. The high end point was used in the Georgia Air Toxic Guideline Assessment. If the high end point is used to project HAP emissions, potential emissions of benzene, acetaldehyde, formaldehyde, naphthalene, PAHs, toluene, and xylene would each equal or exceed 10 tpy. This leads to uncertainty about 112(g) applicability. In order to check the

initial assumption that the proposed modification is not a major source of HAPs, Georgia Power will be required to conduct performance tests to determine the emissions of benzene, acetaldehyde, formaldehyde, naphthalene, PAHs, toluene and xylene.

○ Monitoring Requirements

The table below summarizes the individual monitoring requirements of the applicable regulations.

Pollutant	Turbine NSPS GG	Duct Burner NSPS Da	Stack Acid Rain
NOx	Track NOx emissions based on the correlation between NOx emission rate and water-to-fuel ratio. Continuously track fuel consumption. Daily monitoring of the nitrogen content of the natural gas.	NOx CEMS that meets Part 75 requirements. Install and operate a volumetric flow monitor in the stack. Install and operate a continuous monitoring system for measuring the oxygen or CO ₂ (diluent) content of the flue gas at the location the NOx emissions are monitored. Install and operate a wattmeter to measure electrical generation.	NOx CEMS Volumetric flow CO ₂ (diluent) content of the flue gas. Heat input measurement requirement.
SO ₂	Daily monitoring of the sulfur content of the natural gas.	No monitoring required since the duct burners will be fired exclusively with natural gas.	Assume SO ₂ emission rate of 0.0006 lb/MMBtu for pipeline natural gas.
Opacity	No monitoring required.	No monitoring required since the duct burners will be fired exclusively with natural gas.	No monitoring required since the system will be fired exclusively with natural gas.
CO	No monitoring required.	No monitoring required.	No monitoring required.
VOC	No monitoring required.	No monitoring required.	No monitoring required.
PM/PM10	No monitoring required.	No monitoring required.	No monitoring required.
HAPs	No monitoring required.	No monitoring required.	No monitoring required.

EPD proposes the following monitoring requirements based on EPD's assessment of the overlapping monitoring requirements and Georgia Power's request for Part 70 streamlining:

1. The Acid Rain Regulations and NSPS Da requires continuous monitoring and recording of NO_x emissions, and NSPS Da notes that the continuous emissions monitoring (CEM) requirements of Part 75 (Acid Rain Regulations) suffice for the requirements of NSPS Da. Emissions of NO_x shall be continuously monitored and recorded, in the combined stack of the CT/HRSG system, in accordance with Part 75, which will provide a reasonable assurance of compliance with the NO_x BACT emission standard.

Conclusion:

- Install and operate a NO_x CEM in the stack of each CT/HRSG that meets the requirements of Part 75.
 - Install and operate a diluent monitor in the stack to allow calculation of total NO_x emissions from the CT/HRSG stack in lb/MMBtu.
 - Monitor the gross MW output of the CT and the steam turbine served by the HRSG as required by the Acid Rain regulations. Do not use a wattmeter as required by NSPS Da.
 - Utilize the instrumentation and information already required in Part 75 to measure the heating value and volume of fuel combusted in each CT and the duct burner and calculate total heat input to each CT/HRSG system. Do not install and operate a volumetric flow monitor as defined in NSPS Da.
 - Do not require the installation and operation of devices to continuously monitor and record the consumption of the water to fuel ratio since the turbines are not equipped with water injection.
 - Do not require daily monitoring of the nitrogen content of the natural gas based on an August 14, 1987 EPA memorandum entitled, "Authority for Approval of Custom Fuel Monitoring Schedules under NSPS Subpart GG," which states that nitrogen monitoring can be waived for pipeline quality natural gas.
 - Do not require daily monitoring of the sulfur content of the natural gas. Instead, require a semi-annual analysis of the sulfur content of the natural gas based on EPD's approval of a semi-annual schedule for the natural gas supplier (formerly known as Southern Natural Gas).
2. Each CT/HRSG train will only fire natural gas as BACT for SO₂. The sulfur content of pipeline quality natural gas is very low and the likelihood of exceeding the NSPS Da SO₂ emissions limits for the duct burner and the NSPS GG fuel sulfur content is minimal. The alternative custom fuel sulfur monitoring schedule for NSPS GG is semiannual, and NSPS Da prescribes no monitoring requirements for the duct burner since it is to be only fired with natural gas. Title V periodic monitoring shall consist of a semiannual analysis of the pipeline natural gas to verify the assumption that the sulfur content is low (i.e., <0.8 weight percent). In addition, the Acid Rain Regulations specify monitoring requirements for SO₂ emissions.
 3. Performance tests are to be conducted on two stacks (i.e., combined stacks for turbine and HRSG) at base load while burning natural gas for PM and visible emissions. Natural gas is a clean burning fuel and there is a reasonable assurance that the tests will indicate PM emissions and visible emissions are well below the allowable limits. Hence, no periodic monitoring for PM and opacity is prescribed.
 4. Emissions of CO and total organic compounds are dependant upon temperature in the turbine combustion chamber and typically increase as the temperature decreases. Additionally, the combustion temperature for

a given turbine load is also very consistent and only decreases with a decrease in turbine load. Seventy-five (75) percent load is the minimum permitted operating level, and Georgia Power is required to conduct a CO emissions performance test at base load and 75 percent load to verify compliance with the allowable CO BACT limit. Monitoring turbine load is sufficient for assuring compliance with the CO BACT limit. Since the minimum permitted operating level is 75 percent load and since emissions of total organic carbon follow the same trends as does CO, monitoring turbine load is sufficient for assuring compliance with the VOC BACT limit. Note that 75 percent of base load is approximately 170 MW (each CT)*0.75 equals 127.5 MW.

5.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required of the ambient impacts associated with the construction and operation of the proposed modification. The main purpose of the air quality analysis is to demonstrate that new emissions emitted from the proposed major modification, 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. NAAQS exist for NO₂, CO, PM₁₀, SO₂, Ozone (O₃), and lead (P_b). PSD increments exist for SO₂, NO₂, and PM₁₀.

A separate air quality analysis is required for each of these pollutants to be emitted in a significant amount over the PSD significant threshold. As shown in Table 1, CO, NO_x, SO₂, PM/PM₁₀, and VOC are to be emitted in amounts over their respective PSD significant thresholds. Thus an air quality analysis must be performed for these air pollutants.

Compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources of air pollution (modeled source impacts plus measured background concentrations) and the modeled ambient impact caused by the applicant's proposed emission increase and associated growth. It is important to note that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

The first step in this air quality analysis is to estimate the ambient concentrations that will result from the proposed modification. Dispersion models are the primary tools used to estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The estimated total concentrations must demonstrate compliance with the applicable NAAQS or PSD increments.

In analyzing the air quality impact from the CT/HRSFG facility, two levels of modeling were conducted: screening modeling, using an array of hypothetical hourly meteorological conditions with winds blowing in the direction of the highest terrain elevations; and refined modeling, with 5 years of meteorological data and refined terrain elevations. Screening modeling identifies worst case concentrations from the source by assuming winds directed at the highest terrain for any direction at a given distance from the stack. Refined modeling provides a more realistic evaluation of concentrations from the source by examining terrain elevations in all directions and actual recorded hourly meteorology over a 5-year period.

The dispersion models are based upon the assumption that the dispersion of pollutants is primarily a function of: wind speed and direction; atmospheric stability conditions; and the effective point of discharge of the exhaust plume. To predict ambient air concentrations, the models simulate the plume exhausting from the stack, rising a certain distance in the atmosphere, leveling off, and continuing downwind over relatively flat terrain. The concentrations of pollutants are assumed to have a Gaussian distribution about the longitudinal centerline of the plume.

Both simple terrain screening and refined modeling were conducted using the U.S. EPA's Industrial Source Complex Short Term (ISCST3) model. The ISCST3 model combines the evaluated concentrations for a range of possible meteorological conditions for both simple terrain (below stack top) and complex terrain (above stack top).

ISCST3 is a Gaussian plume dispersion model which estimates hour-by-hour ground level concentrations of emissions from an elevated source. The model provides maximum 1-hour, 3-hour, 24-hour, and annual average concentrations for receptors located on a radial grid spaced at ten degree intervals around the source for various downwind distances, and also takes into account the effect of downwash caused by nearby buildings and structures.

In this case both on-site and off-site meteorological (met) data were used in the review. EPD used surface data from Columbus, Georgia and upper air data from Centreville, Alabama for the 5-year period from 1985-1989 and one-year on-site data collected at Plant Yates (1986-1987) in this evaluation.

The modeling of the CTs was performed using actual stack heights since the proposed stack heights do not exceed “good engineering practice” (GEP) requirements. Since, the proposed stack height is less than the calculated GEP height; building downwash needs to be considered for the air quality analysis. The U.S. EPA's Building Profile Input Program (BPIP) was used to determine the building heights and widths that can cause downwash of the plume on a direction specific basis. Variable stack parameter data and maximum emission rates are presented in Table 1 of the Air Quality Modeling Chapter in Georgia Power’s permit application.

The radius of influence for the modeling study was 25,000 meters in each major compass direction from the facility, with receptors located every 100 meters out to 4,000 meters, and every 500 m out to 25,000 meters. The proposed stack height for the combustion turbines is 131 feet, and the plant base elevation is approximately 755 feet.

The first analysis is to run the dispersion model only using the proposed emission rates from the modification at Plant Wansley, and the results of this analysis are compared to the PSD significant impact levels (SILs) and the de minimis concentrations for preconstruction monitoring. The following table illustrates the results of the first modeling analysis.

Pollutant	Averaging Period	Preconstruction Monitoring Evaluation (ug/m ³)	PSD Significant Impact Level (ug/m ³)	Projected Concentration (ug/m ³)
CO	8 hour 1 hour	575 No 1 hour	500 2,000	184 411
NO ₂	Annual	14	1	1.55
PM ₁₀	Annual 24 hour	No annual 10	1 5	1.05 13.1
SO ₂	Annual 24 hour 3 hour	No annual 13 No 3 hour	1 5 25	0.08 1.0 3.1

VOC	No significant air quality concentration for ozone monitoring has been established. Instead, applicants with a net emissions increase of 100 tons per year or more of VOCs subject to PSD would be required to perform an ambient impact analysis, including pre-application monitoring data	
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Predicted concentrations from the modeling study were above the de minimis preconstruction monitoring concentrations for PM₁₀ and the site will result in a net VOC emissions increase of greater than 100 tpy. Exemption from preconstruction monitoring requirements for PM₁₀ and ozone (VOC) are justified on the basis of the extensive existing monitoring network in Georgia for these air pollutants. Predicted concentrations from the modeling study were above the SILs for PM₁₀ and NO_x. Thus, PSD increment and NAAQS modeling are required for PM₁₀ and NO_x. The NAAQS and PSD increment modeling analysis was performed using emissions from the proposed modification at Plant Wansley along with other PSD facilities within the significant impact area (SIA). EPD determined the approximate size of the SIA for PM₁₀ and NO_x to be approximately 29 and 13 kilometers, respectively.

EPD performed an emissions inventory of the facilities which emit PSD significant amounts of emissions of NO_x and PM₁₀, that fall within the SIA, and that fall within 50 km of the SIA for these pollutants that were determined to be significant based on the “20D” rule. A facility is included by the “20D” rule if its annual emissions in tons per year are greater than 20 times the distance from the proposed source. The other facilities contributing emissions to the modeling area are Tenaska Generating Facility, Georgia Power Plant McDonough/Atkinson, Georgia Power Plant Yates, Georgia Power Plant Wansley, Heard County Power, LLC (Dynergy), West Georgia Generating Company, Blue Circle Cement, and Medusa Cement Company.

The dispersion model was run to estimate the total impact to be compared to the applicable NAAQS and the results are illustrated in the following table:

Pollutant	Averaging Period	NAAQS (ug/m ³)	Projected Concentration (ug/m ³)
NO ₂	Annual	100	15.1
PM ₁₀	Annual	50	26.6
	24 hour	150	118.2

The dispersion modeling results show that the total impact is below the NAAQs. The results are also summarized in Appendix C, Table II-8 which also shows there is little contribution from the proposed source.

For purposes of PSD increment consumption, Heard County is classified as a Class II area. The allowable increases in pollutant concentrations (increments) for a Class II area are given in Table II-1 in Appendix C.

The PSD minor source baseline data for PM₁₀ and NO₂ in Heard County is April 30, 1998. Other PSD increment consuming sources included in the PSD increment analysis were Tenaska Generating Facility, an existing combustion turbine at Plant Wansley, Heard County Power, LLC (Dynergy), and West Georgia Generating Company. The resulting PSD Class II increment consumption are summarized in Appendix C, Table II-1 for the proposed project, and in Table II-2 for all increment consuming sources. The largest predicted consumption of

any Class II increment was 39 percent of the PM₁₀ 24-hour increment. Hence, the total impact does not consume all of the available PSD increments.

PSD review requires that sources located within 100 kilometers of a Class I area be evaluated for possible impact on that area. Since the proposed project is located approximately 150 km from the nearest Class I Area (Cohutta NWA), PSD Class I Ambient Air Quality modeling was not conducted.

There are no applicable NAAQS or specific Georgia ambient air standards for the non-criteria pollutants listed in Table 1. Impacts from each of the pollutants listed in this letter were analyzed using the EPD Guidance for Ambient Impact Assessment of Toxic Air Pollutant Emissions (referred to as the Georgia Air Toxics Guideline; Version June 21, 1998). The Georgia Air Toxics Guideline is a guide for estimating the environmental impact of sources of toxic air pollutants. A toxic air pollutant is defined as any substance which may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. The ISCST3 computer dispersion model was used to predict the maximum 24-hour average ground level concentration (referred to as MGLC) for each pollutant in question. Georgia Power and EPD used the high end point of the HAP emission factor range to perform the toxic guideline assessment. Each MGLC is compared to its respective acceptable ambient concentration (referred to as AAC). The basis for calculation of the AAC comes from the pollutant toxicity rating systems described in the Georgia Air Toxics Guideline. Based on EPD's analysis, the predicted MGLC's for each applicable pollutant is below the Georgia EPD AACs. A table of air toxic modeling results is provided in Appendix C of this preliminary determination.

The project also is subject to an additional impacts analysis that assesses the impacts of air pollution on soils and vegetation caused by emissions of regulated pollutants from the project, and from associated growth in the project vicinity.

6.0 ADDITIONAL IMPACT ANALYSES

6.1 General

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of the facility and an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the facility. Other impact analysis requirements may also be imposed on a permit applicant under local, State or Federal laws which are outside the PSD permitting process.

6.2 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 into 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.

For PSD sources, the principal visibility impacts of concern are impacts on the visibility conditions within the nearest PSD Class I area. The proposed facility is more than 100 km away from the nearest Class 1 area; however, Georgia Power performed plume visibility impact on the Cohutta Class I area. They performed this analysis using the plume visual impact screening model called VISCREEN.

Georgia Power performed a Level-1 screening analysis, and a Level-1 screening is designed to provide plume visual impacts that would be larger than those calculated with actual meteorological conditions. Visibility impact was analyzed by reviewing the change in brightness, hue, and saturation as the line of sight changed. Georgia Power predicted that the impacts, as the line of sight changes, are below the applicable thresholds set by EPA; thus indicating that visibility impairment, attributed solely to the proposed modification, could be ruled out. EPD concurs with these findings.

6.3 Soils and Vegetation

The maximum concentrations of criteria air pollutants predicted by modeling were compared to available standards that are known to protect local soil and vegetation.¹⁰ Georgia Power, and EPD, conclude that no sensitive soil types are known to exist in the vicinity of the project. The EPA Manual noted in the reference footnote indicates that vegetation is protected if air pollutant concentrations for NO_x, CO, and PM stay below specific thresholds for different plants. For the most sensitive plants discussed in the publication above, no effect occurs below the thresholds resulting from the modeling analysis. Note the maximum expected concentration is from all combined sources in the area.

Pollutant	Standard (ug/m ³)	Maximum Expected Concentration (ug/m ³)

¹⁰ *Diagnosing Vegetation Injury Caused by Air Pollution*, U.S. EPA - Office of Air Quality Planning and Standards, RTP, NC, 1976.

NOx	370 (500 hours continuous exposure)	1.55 ug/m ³ (Annual average)
CO	110,000 (600 hours continuous exposure)	411 (1 hour average)
PM	60 (24 hours [secondary NAAQS])	13.1 (24 hour average)

Based on these findings, there should not be any adverse effects on soils or vegetation, attributed solely to the proposed modification.

6.4 Growth

The proposed project is being constructed to meet current electric demands. Additional growth as a direct result of the additional electric power provided by the project is not expected. Access to the project site for all vehicular traffic will be from Georgia Highway 5. The proposed project will be operated remotely.

As a result of the small project size and minimal manpower requirements, it is expected that the construction and operational support and services required by the facility will, for the most part, be available from existing resources in the region. Therefore, it is anticipated that the facility will not result in any appreciable area wide industrial, commercial, or residential growth in order to support the project.

7.0 **OFFSET REQUIREMENTS**

The proposed expansion of Plant Wansley must comply with Georgia Rules 391-3-1-.03(8)(c)1-12. and (c)15 and Georgia Rule 391-3-1-.03(8)(e). As noted earlier, Georgia Rule 391-3-1-.03(8)(c)15 is referred to as the BACT-Offset Rule. Potential NOx emissions from the proposed expansion exceeds 40 tons per year which is the PSD significance threshold for this pollutant. In this case, the BACT-Offset rule requires the employment of BACT and the offset of NOx emissions at a 1.1 to 1.0 ratio.

The offsetting emissions must be real, permanent, quantifiable, enforceable, surplus, and have occurred after December 31, 1996 and by the date that each phase commences commercial operation. The terms “real,” “permanent,” “quantifiable,” “enforceable,” and “surplus” are defined in Georgia Rule 391-3-1-.03(13)(i) as follows:

Real: Means a reduction in actual emission emitted into the air.

Permanent: Means assured for the life of the corresponding Emission Reduction Credit through an enforceable mechanism such as a permit condition or revocation.

Quantifiable: Means that the amount, rate, and characteristic of the Emission Reduction Credit can be estimated through a reliable method and are approved by the Division.

Enforceable: Means enforceable by the Division. Methods for ensuring that Emission Reduction Credits are enforceable shall include, but not be limited to, conditions in air quality construction or operating permits issued by the Division.

Surplus: Means not required by any local, state, or federal law, regulation, order or requirement and in excess of reductions used by the Division in issuing any other permit or to demonstrate attainment of federal ambient air quality standards or reasonable further progress towards achieving attainment of federal ambient air quality standards. For the purpose of determining the amount of surplus emission reductions, any seasonal emission limitation or standard shall be assumed to apply throughout the year. Emission reductions which have previously been used to avoid New Source Review through a netting demonstration are not considered surplus.

NOx emission reductions may be created by any of the following methods to be eligible for consideration as Emission Reduction Credits in accordance with Georgia Rule 391-3-1-.03(13)(b):

- a. Installation of control equipment;
- b. A change in process inputs, formulations, products or product mix, or raw materials;
- c. A reduction in actual emission rate;
- d. A reduction in operating hours;
- e. Production curtailment;
- f. Shutdown of emitting sources or facilities; or
- g. Any other enforceable method as determined by the Division.

In accordance with Georgia Rule 391-3-1-.03(13)(a), NOx emission reductions can be obtained from any stationary source as follows:

- a. Any stationary source located within the counties of Cherokee, Clayton, Cobb, Coweta, DeKalb, Douglas, Fayette, Forsyth, Fulton, Gwinnett, Henry, Paulding, and Rockdale which has the potential to emit NOx or VOC in amounts greater than 25 tons per year.
- b. Any stationary source located within the counties of Bartow, Carroll, Hall, Newton, Spalding, and Walton and which has the potential to emit NOx or VOC in amounts greater than 100 tons per year.
- c. Any electrical generating unit located at any stationary source within the counties of Banks, Barrow, Butts, Chattooga, Clarke, Dawson, Floyd, Gordon, Haralson, Heard, Jackson, Jasper, Jones, Lamar, Lumpkin, Madison, Meriwether, Monroe, Morgan, Oconee, Pickens, Pike, Polk, Putnam, Troup, and Upson which has the potential to emit NOx or VOC in amounts greater than 100 tons per year.

NOx and VOC inter-pollutant emission offset trading is not allowed.

Part 2 of this Preliminary Determination specifies that the potential to emit of NOx emissions from the proposed expansion at Plant Wansley are 1040.7 tons during any twelve consecutive months. The required NOx offsets are computed as follows:

$$\text{NOx} = 1040.7 \times 1.1 = 1,144.77 \text{ tpy}$$

The required NOx offsets per CT/HRSG train are computed as follows:

$$\text{NOx} = 1,144.77 \text{ tpy} \div 8 \text{ CT/HRSG trains} = 143.1 \text{ tpy}$$

Georgia Power proposed commercial operation for the first two blocks (four CT/HRSG trains), Phase I, on June 1, 2002. The commercial operation for the third block (two CT/HRSG trains), Phase II, on June 1, 2004. The commercial operation for the fourth block (two CT/HRSG trains), Phase III, on June 1, 2005. The allowable NOx limit for the eight CT/HRSG trains combined is 1,040 tons during any twelve consecutive months.

The required NOx offsets for Phase I are computed as follows:

$$\text{NOx} = 143.1 \text{ tpy per CT/HRSG train} \times 4 \text{ CT/HRSG trains} = 572.4 \text{ tpy}$$

The required NOx offsets for Phase II and Phase III are computed as follows:

$$\text{NOx} = 143.1 \text{ tpy per CT/HRSG train} \times 2 \text{ CT/HRSG trains} = 286.2 \text{ tpy}$$

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed modification are included as Permit Number 4911-149-0001-V-01-2, an amendment to the Title V Permit for the Wansley Steam-Electric Generating Plant. A spreadsheet has been developed, and is included in Appendix A, which specifies the overlapping applicable requirements and how they were included in the Permit amendment.

PART 1.0 FACILITY DESCRIPTION

Condition 1.3 (Overall Facility Process Description) is revised to include the proposed modification.

PART 3.0 REQUIREMENTS FOR EMISSION UNITS

Condition 3.1 (Emission Units) is revised to included the new equipment from the proposed modification.

Condition Nos. 3.3.4 through 3.3.9 have been included to specify the dates by which construction on each phase must commence as well as when a new BACT study is required.

Condition 3.3.10 defines the common stacks in the proposed modification.

Condition Nos. 3.3.11 through 3.3.12 define BACT for SO₂ emissions.

Condition 3.3.13 defines the NOx BACT emission limit per combined cycle block. Block one includes CT6A/DB6A and CT6B/DB6B, Block two includes CT7A/DB7A and CT7B/DB7B, Block three includes CT8A/DB8A and CT8B/DB8B, and Block four includes CT9A/DB9A and CT9B/DB9B. The NOx emission limit per block is 1,040.7 divided by four blocks equals 260.175 tons per year.

Condition 3.3.14 specifies a combustion turbine operational limitation for purposes of reasonably assuring compliance with the CO BACT emission limit.

Condition 3.3.15 defines the NOx BACT emission limit.

Condition 3.3.16 defines the CO BACT emission limit.

Condition 3.3.17 defines BACT for PM/PM₁₀ emissions.

Condition 3.3.18 defines BACT for VOC emissions.

Condition 3.3.19 defines BACT for visible emissions (opacity).

Condition Nos. 3.3.20 through 3.3.22 defines BACT to be employed on the proposed modification.

Condition Nos. 3.4.7 through 3.4.9 defines the NOx offsetting requirements of the BACT-Offset Rule.

PART 4.0 REQUIREMENTS FOR TESTING

Condition 4.1.3 - This condition has been revised as follows:

- a) Original Condition 4.1.3(h) has been removed as it referenced Method 7 or 7E. This is not an applicable reference test method for the existing equipment.
- b) Original Condition 4.1.3(g) has been modified to include the proposed turbines.
- c) Method 25A is added as the VOC reference test method.
- d) Method 18 and SW-846 Method 0011 are added as reference test methods for specific HAPs.

Condition 4.2.2 - This condition specifies the PSD/Title V performance testing requirements.

Condition 4.2.3 - After the initial performance test for the duct burners, Subpart Da requires that compliance be based on a 30-day rolling average (which happens to be the averaging time for the PSD NOx BACT limit).

PART 5.0 REQUIREMENTS FOR MONITORING (Relative to Data Collection)

Condition 5.2.1 has been revised to include condition nos c and d.

Condition 5.2.7 - This condition is added for establishing the minimum data requirement, data reduction, and 40 CFR 60 Appendix F applicability as they related to the Continuous Monitoring System required by Condition 5.2.1d.

Condition 5.2.8 - Defines the methods and procedures to supplement the Continuous Monitoring System data.

Condition 5.2.9 - This condition is added to define the procedures used to show compliance with the tons per year limit. This condition requires the use of Part 75 monitoring procedures to calculate mass emission rates.

Condition Nos. 5.2.10 - 5.2.12 - These conditions are added to define the PSD requirements for implementing Subpart GG for the turbines and 40 CFR 70.6(a)(3)(i) for the duct burners.

Condition 5.2.13 - This condition is added to require the determination and recording of the electrical output (in MWs) for each combined combustion turbine and heat recovery steam generator for each hour of operation. The MWs are compared to the MWs at 75% load in order to reasonably assure compliance with the CO BACT emission limit.

Condition 5.2.14 - This condition defines deviations and/or excess emissions, and this condition has been expanded to include conditions f-h for the proposed modification.

Condition 5.3.7 - This condition was added for PSD purposes as a way to implement 40 CFR 60.47a(c) and 60.49a(b) for the duct burners. Several changes have been made to Subpart Da which are as follows: (1) 60.49a(b) is only implemented for NO_x; (2) In (b) “(lb/MMBtu)” was changed to “(ppm, corrected to 15% oxygen)”, the units of the most stringent limit; (3) In (d) “(NO_x only)” was deleted since this condition only applies to NO_x; (4) Paragraph (f) was deleted since an F factor is not needed when calculating emissions in units of ppm, corrected to 15% oxygen; (5) Paragraph (k) was deleted since Subpart Da specifically says data for Da compliance should not use the data substitution or bias corrections from Part 75.

Condition 5.3.8 - Defines reporting requirements for 12-month total NO_x limit and this condition is used in conjunction with Condition 5.2.9.

PART 6.0 OTHER RECORD KEEPING AND REPORTING REQUIREMENTS

Condition 6.2.4 - This condition implements the PSD record keeping requirements for natural gas consumption by each turbine and duct burner.

Condition 6.2.5 - This condition implements the requirements of 40 CFR 60.49a(b) as it relates to SO₂ emissions and opacity.

Condition 6.2.6 - This condition implements the requirements of 40 CFR 60.49a(f) and applies them to the combined turbine and duct burner stack.

Condition 6.2.7 - This condition implements certain portions of the reporting requirements of 40 CFR 60.49a(g) which relate to 40 CFR 60.47a. 40 CFR 60.47a(e), (f), (g), (h), (k), and (l) are not applicable to systems calibration, span and drift checks, etc.

Condition 6.2.8 - This condition implements the reporting requirements of 40 CFR 60.49a(c) for the combined turbine and duct burner system.

Condition 6.2.9 - This condition implements the applicable paragraphs of 40 CFR 60.7.

Condition 6.2.10 - This condition requires the submittal of various items as they relate to the NO_x offsetting emission reductions.

PART 7.0 OTHER SPECIFIC REQUIREMENTS

Condition 7.9.9 specifies the SO₂ allowance allocations and NO_x requirements for the new CT/HRSG trains.

Condition 7.14.1 allows the Division to reopen the Permit if the 112(g) applicability determination is different than that proposed in this Preliminary Determination.

Appendix A

Draft PSD and Title V Permit Amendment for Modification at Plant Wansley (Includes spreadsheet outlining various overlapping requirements)

Appendix B

Georgia Power PSD Permit Application and Supporting Data

Contents include:

1. PSD permit application no. 11857 dated November 29, 1999.
2. Derivation of Potential HAP emissions.
3. Derivation of Ammonia Emission Rate vs. Compliance with Georgia Air Toxics Guideline.
4. Electronic mail from Fred Ellis (Southern Company Generation) to Susan Jenkins (EPD) dated January 28, 2000.
5. Electronic mail from Susan Jenkins (EPD) to Charles Solt (Catalytica) dated February 2, 2000.
6. Electronic mail from Charles Solt (EPD) to Susan Jenkins (EPD) dated February 7, 2000.
7. Letter from Doug Neeley (EPA Region IV) to Chris Hobson (Georgia Power) dated February 11, 2000.
8. Letter from Susan Jenkins (EPD) to Rick Oegema (ABB ALSTOM Power) dated February 16, 2000.
9. Letter from Susan Jenkins (EPD) to Fred Ellis (Southern Company Generation) dated February 16, 2000.
10. Letter from Fred Ellis (Southern Company Generation) to Susan Jenkins (EPD) dated March 21, 2000.
11. Facsimile from Susan Jenkins (EPD) to Charles Hayes (Georgia Power) dated April 4, 2000.
12. Letter from Charles Goodman (Southern Company Generation) to John Seitz and David Mobley (EPA) dated April 13, 2000.
13. Letter from Charles Hayes (Georgia Power) to Susan Jenkins (EPD) dated April 25, 2000.
14. Letter from Charles Hayes (Georgia Power) to Susan Jenkins (EPD) dated May 3, 2000.
15. Letter from Graham Holden to James Capp (EPD) dated May 10, 2000.

DERIVATION OF POTENTIAL HAP EMISSIONS

Assumptions:

- Maximum heat input of combined CT/HRSG system = 2281.5 MMBtu/hr (taken from page 3-8 in Application No. 11857).
- potential HAP emission = (EF in lb/MMBtu)*(2281.5 MMBtu/hr)*(8760 hrs/yr)*(1 ton/2000 lb)*8 systems

Pollutant	Low End	High End
Acetaldehyde	1.1 x 10 ⁻⁵ lb/MMBtu PTE = 0.88 tpy	3.5 x 10 ⁻⁴ lb/MMBtu PTE = 28 tpy
Acrolein	6.08 x 10 ⁻⁶ lb/MMBtu PTE = 0.49 tpy	7.75 x 10 ⁻⁶ lb/MMBtu PTE = 0.62 tpy
Arsenic Compounds	4.80 x 10 ⁻⁸ lb/MMBtu PTE = 0.0038 tpy	Same as low end.
Benzene	1.30 x 10 ⁻⁶ lb/MMBtu PTE = 0.103 tpy	1.37 x 10 ⁻⁴ lb/MMBtu PTE = 10.95 tpy
Ethylbenzene	2.3 x 10 ⁻⁵ lb/MMBtu PTE = 1.84 tpy	4.10 x 10 ⁻⁵ lb/MMBtu PTE = 3.28 tpy
Formaldehyde	6.70 x 10 ⁻⁶ lb/MMBtu PTE = 0.54 tpy	3.33 x 10 ⁻³ lb/MMBtu PTE = 266.2 tpy
Mercury	4.31 x 10 ⁻⁷ lb/MMBtu PTE = 0.034 tpy	Same as low end.
Naphthalene	5.54 x 10 ⁻⁷ lb/MMBtu PTE = 0.044 tpy	1.37 x 10 ⁻⁴ lb/MMBtu PTE = 10.95 tpy
Polyaromatic Hydrocarbons (PAHs)	7.97 x 10 ⁻⁷ lb/MMBtu PTE = 0.064 tpy	1.76 x 10 ⁻⁴ lb/MMBtu PTE = 14.07 tpy
Toluene	2.10 x 10 ⁻⁵ lb/MMBtu PTE = 1.68 tpy	1.42 x 10 ⁻⁴ lb/MMBtu PTE = 11.21 tpy
Xylene	2.65 x 10 ⁻⁵ lb/MMBtu PTE = 2.12 tpy	1.20 x 10 ⁻⁴ lb/MMBtu PTE = 9.60 tpy

AMMONIA EMISSIONS VS. GEORGIA AIR TOXICS GUIDELINE

Assumptions:

1. Formaldehyde emission factor = 3.3×10^{-3} lb/MMBtu, Maximum ammonia slip = 10 ppmv
2. Maximum heat input from the combined CT/HRSG system = 2281.5 MMBtu/hr
3. Volume flow rate from stack = 913,122 acfm (taken from Application No. 11857). Assume valid at the specified heat input in assumption no. 2.
4. Exhaust characteristics:
E = 1 g/s
Stack height = 132 feet
Exit velocity = 69.1 fps
Exhaust temperature = 182⁰F
5. Ammonia has an annual AAC = 100 ug/m³
6. Ammonia has a 15-min STEL AAC = 2400 ug/m³

Step 1: What is the maximum ammonia emission rate?

- a. The high end point in the EPA emissions database for formaldehyde:

$$\text{Formaldehyde emissions} = (3.3 \times 10^{-3} \text{ lb/MMBtu}) * (2281.5 \text{ MMBtu/hr}) = 7.5 \text{ lb/hr (total all 8 turbines)}$$

- b. Assume a maximum ammonia slip of 10 ppmv per turbine/HRSG unit:

$$(10 \text{ ppmv}) * (17) / 24.5 = 6.93 \text{ mg/m}^3$$

$$\text{Emissions} = (6.93 \text{ mg/m}^3) * (1 \text{ gram}/1000 \text{ mg}) * (2.205 \text{ lb}/1000 \text{ grams}) * (1 \text{ m}^3/35.31 \text{ cft}) * (913,122 \text{ cft/min}) * (60 \text{ min/hr}) = 23.71 \text{ lb/hr-turbine}$$

Step 2: Run SCREEN Model

At 1 g/s, yields a one-hour maximum ground level concentration (MGLC) = 1.45 ug/m³

Step 3: Convert SCREEN mg/c to the AAC and STEL averaging times:

$$\text{Cannual} = 1.45 \text{ ug/m}^3 * 0.08 = 0.116 \text{ ug/m}^3$$

$$\text{C 15 min} = 1.45 \text{ ug/m}^3 * 1.32 = 1.914 \text{ ug/m}^3$$

Step 4: Determine mass emission rate necessary to exceed Ammonia AAC and STEL:

$$\text{Annual, lb/hr} = (100 \text{ ug/m}^3) * (1 \text{ g/s}) / 0.116 \text{ ug/m}^3 * (3600 \text{ sec/hr}) * (2.205 \text{ lb}/1000 \text{ g}) = 6,843 \text{ lb/hr}$$

$$\text{15-min lb/hr} = (2400 \text{ ug/m}^3) * (1 \text{ g/s}) / (1.914 \text{ ug/m}^3) * (3600 \text{ sec/hr}) * (2.205 \text{ lb}/1000 \text{ g}) = 9,954 \text{ lb/hr}$$

Appendix C

EPD's PSD Dispersion Modeling and Air Toxics Assessment Review