Prevention of Significant Air Quality Deterioration Review

Final Determination

April 2010

Facility Name: Vogtle Electric Generating Plant
City: Waynesboro
County: Burke
AIRS Number: 04-13-033-00030
Application Number: 18986
Date Application Received: May 27, 2009

State of Georgia
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BACKGROUND

On May 27, 2009, Vogtle Electric Generating Plant (hereafter Plant Vogtle) submitted an application for an air quality permit to construct and operate equipment to support new nuclear Units 3 and 4. The facility is located at 7821 River Road in Waynesboro, Burke County. The project will install 4 cooling towers and 13 diesel engines with diesel fuel storage tanks. The new emission units are supplemental equipment used in the operational and safety systems of the nuclear units. The electricity provided to the grid is exclusively provided by the nuclear power generating units. The existing emission units are not being modified. The nuclear units are subject to review and licensing by the U.S. Nuclear Regulatory Commission (NRC) and not by the Georgia Environmental Protection Division; therefore, the nuclear units are not discussed in detail in this Final Determination.

On March 4, 2010, the Division issued a Preliminary Determination stating that the modifications described in Application No. 18986 should be approved. The Preliminary Determination contained a draft Air Quality Permit for the construction and operation of the modified equipment.

The Division requested that Plant Vogtle place a public notice in a newspaper of general circulation in the area of the existing facility notifying the public of the proposed construction and providing the opportunity for written public comment. Such public notice was placed in *The Augusta Chronicle* on March 7, 2010. The public comment period expired on April 6, 2010.

During the comment period, comments were received from U.S. EPA Region IV, the facility, and the general public.

A copy of the final permit is included in Appendix A. A copy of written comments received during the public comment period is provided in Appendix B.

U.S. EPA REGION 4 COMMENTS

Comments were received from Gregg M. Worley, Chief, Air Permits Section, U.S. EPA Region 4, by letter on April 5, 2010. The comments are typed, verbatim, below and were the result of review by Lori Shepherd of U.S. EPA Region 4. The introductory paragraph of the letter states, "Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), and volatile organic compounds (VOC)." The Permittee is limited by permit condition to a diesel fuel sulfur limit of 15 parts per million by weight (ppmw). The 15 ppmw fuel sulfur limit results in a SO_2 potential to emit of 1.5 tons per year, which is far below the PSD significant emission rate of 40 tons per year.

Comment 1

Upon review of the permit application as well as Southern Company's response to comments from EPD dated September 11, 2009 and the preliminary determination, EPA Region 4 considers the Best Available Control Technology (BACT) analyses for NO_x, CO, $PM/PM_{10}/PM_{2.5}$, SO_2, and VOC to be incomplete. Although various options are identified in each analysis, the applicant states that without specific engine data a complete analysis of each technically feasible technology is not possible. The application and subsequent communication from the applicant proposes emissions limits similar to those established for recently permitted facilities as identified in the RBLC database. Although EPA agrees that the end result may be comparable, this method does not adequately document a complete BACT analysis as required for the Vogtle Electric Generating Plant facility. Data from engines currently in use for generating plant Units 1 and 2 or from engines being considered for use in the newly constructed units may be used to formulate reasonable BACT limits and complete the "top down" method as detailed in the 1990 draft U.S. E.P.A. *New Source Review Workshop Manual*. *NOTE- This comment was also submitted by one organization in the general public on the permit application; that organization did not comment on the draft permit.*

EPD Response:

The Division agrees with Region 4 that the BACT analysis for the engines, which was submitted by Southern Company, as part of the PSD application, is "incomplete" for carbon monoxide (CO), nitrogen oxides (NOx), volatile organic compounds (VOC), and particulate matter ($PM/PM_{10}/PM_{2.5}$). [Note that, for this application, the proposed increase in emissions of sulfur dioxide was not significant and therefore no BACT analysis was necessary. Also, EPD has come to an agreement with Southern Nuclear to limit the emissions of PM2.5 from the project to less than 10 tons per year. Thus the project is PSD minor for PM2.5 and No PM2.5 BACT determination is required and no PM2.5 modeling is required.] In particular, EPD agrees that the initial determination contained no cost analysis to justify their conclusion that add-on control equipment was not cost effective for the engines powering generators and fire pumps. Therefore, EPD requested that Southern Company submit such a cost analysis. EPD also consulted with a representative of Miratech, which is a respected supplier of NOx control equipment. In EPD's response to EPA's comment, the pollutants of CO, NOx, VOC, and $PM/PM_{10}/PM_{2.5}$ are reviewed.

Before proceeding with the review, EPD narrowed down the equipment for which add-on controls are possible. According to the representative from Miratech, Underwriters Laboratories, the organization that certifies the safety of fire pumps that are manufactured, will withdraw their certification if add-on control devices are installed. While this agency does theoretically allow for the installation of a control device, if required by a permitting agency, this is only allowed if the control device would be automatically bypassed in an emergency, in case the control device was affecting the performance of the fire pump. Miratech believes that such a device is infeasible and there have been no uses of this provision. Therefore, EPD has determined that a top down BACT analysis for fire pumps, with a cost

analysis, would be fruitless and so did not request that. However, EPD requested that a cost analysis for add-on controls for all other engines be provided.

In their cost analysis, Southern Nuclear analyzed add-on controls, making the following assumptions:

1. The engines were assumed to be those available in the year 2014, which is the year they plan to purchase them. The New Source Performance Standards (NSPS – 40 CFR 60 Subpart IIII) for engines provides emission limits, so the uncontrolled emission rates of pollutants was assumed to be the NSPS emission limits or lower, if the BACT determined showed that was possible.

2. Annual usage of each engine of 500 hours. Though this value far exceeds the run time of any current engine on site, this is based on the conservative value specified in Georgia's Potential to Emit (PTE) Guidelines.

3. Annualized costs include capital recovery (10 year equipment life and 7% interest), maintenance, and operation.

NOx

Because of the importance of NOx emissions in the generation of ozone in the Southeast, the cost analysis for NOx emissions is reviewed first in this response. For the BACT review, Southern Nuclear included the following possible control technologies:

- Combustion Process Design
- Non-Selective Catalytic Reduction (aka 3-way catalyst)
- Exhaust Gas Recirculation (with NSCR)
- Selective Catalytic Reduction
- EMx™ (SCONOx™)

Elimination of technologically infeasible controls.

EMx™ SCONOX was deemed technologically infeasible because "There have been no installations of this technology on reciprocating engines." Southern Nuclear concluded that: "…the use of good combustion process design plus SCR offers the highest level of control for the proposed engines." Therefore, costs were determined for this control equipment (traditional SCR with urea injection), assuming a control efficiency of 90%.

Non-Selective Catalytic Reduction (3-Way Catalysts) were determined by Southern Nuclear and Miratech as technologically infeasible for diesel engines. 3-Way catalyst can only be used on engine exhaust that contains <0.5 % Oxygen (less than 1/2 percent). By nature of the combustion this can only be accomplished on some natural gas and most gasoline engines. When diesel fuel combusts there will always be 6-10% Oxygen present so it would not be a candidate for a 3-way (NSCR) and will always need SCR for NOx reduction. Natural Gas engines that are "Lean Burn" from the factory also contain about the same percentage oxygen, so that is why you will sometimes an SCR on a Lean Burn gas engine.

Cost Analysis for Technologically Feasible Controls

For the 5,560 kW systems, with an estimated total capital investment of $756,160, the annualized cost was estimated to be $173,629 per engine. Given an annual uncontrolled emission rate of 4.9 tons per

year (tpy), the removal of NOx was determined to be 4.4 tpy. The cost effectiveness would therefore be $39,372 per ton.

For the 1500 kW systems, with an estimated total capital investment of $360,000, the annualized cost was estimated to be $79,330 per engine. Given an annual uncontrolled emission rate of 1.33 tpy, the removal of NOx was determined to be 1.2 tpy. The cost effectiveness would therefore be $39,372 per ton.

For the 168 kW systems, with an estimated total capital investment of $54,430, the annualized cost was estimated to be $12,165 per engine. Given an annual uncontrolled emission rate of 0.3 tpy, the removal of NOx was determined to be 0.27 tpy. The cost effectiveness would therefore be $45,056 per ton.

For the 75 kW systems, with an estimated total capital investment of $24,300, the annualized cost was estimated to be $5,431 per engine. Given an annual uncontrolled emission rate of 0.3 tpy, the removal of NOx was determined to be 0.27 tpy. The cost effectiveness would therefore be $20,114 per ton.

Based on these cost estimates, Southern Nuclear determined that add-on control technology was not cost-effective for any of the engines. However, EPD is aware that EPA Region 4 suggested that the cost effectiveness could be based on engines if purchased today. EPD would like to address that suggestion, so requested that Miratech carry out a cost analysis based on add-on controls for the largest engines purchased today. Based on Miratech's analysis, EPD developed the following cost estimate for the 5560 kW systems:

TYPICAL UNCONTROLLED NOx: 8.84 grams per kwhr
TYPICAL CONTROLLED NOx: 0.884 grams per kwhr (@90% removal)
Total NOx removed per engine: 97 pounds per hour.

Purchased equipment cost: $410,000
Direct installation cost: $180,000
Total capital investment: $590,000

Total annual operating expenses: $21,436
Capital Recovery on Total Capital Investment: $87,782/yr (10 yr; 8.5%)

Total Annualized Cost, $109,218/yr
Total NOx removed: 24 tpy (@500 hours per year)
Cost Effectiveness: $4,484/ton removed

As EPA is aware, such a cost per ton is within the range GAEPD has considered cost effective. However, GAEPD does not believe the evaluation should end there, since the actual operating hours of each engine are much less than 500 hours per year. In the last 10 years, no emergency generator at Plant Vogtle (Unit 1 and Unit 2) has been operated during an emergency. Since Plant Vogtle has not operated any generator for more than 50 hours per year, EPD conducted a cost analysis on the realistic assumption that operation only occurs for 50 hours per year. This is justified since the facility will be limiting the operation of the generators by limiting the emissions of PM2.5 from all the new generators to less than 9.48 tons per year.

Total NOx Removed: 2.4 tons/yr
Cost Effectiveness: $44,837/ton NOx Removed

As EPA is aware, this would not be considered cost effective. EPD has also looked at the cost effectiveness of controlling the other engines and determined that the cost per ton, if operating only 50 hours per year, would be in excess of $20,000 per ton, which is also not considered cost effective.

EPD also notes that SCR control equipment must be bypassed for some time (~10 minutes) during start-up, during which time NOx control is nil. Assuming that each engine operated only an hour during each occasion for testing and maintenance, it is therefore quite possible that the overall control efficiency would be lowered to approximately 5/6 of the expected control. Therefore, for engines only operated for testing and maintenance, the overall control would be lower and the cost per ton removed would be higher.

PM/PM10

For the PM BACT review, Southern Nuclear included the following possible control techniques:

- Particulate Filters
- Combustion Process Design
- Ultra Low Sulfur Fuel
- Proper Maintenance

All of these technologies were determined to be available and technically feasible. Southern Nuclear determined that the best control would result if all four control techniques were used. This was assumed to yield 90% control.

For the 5,560 kW systems, with an estimated total capital investment of $83,400, the annualized cost was estimated to be $18,435 per engine. Given an annual uncontrolled emission rate of 0.45 tpy, the removal of PM was determined to be 0.41 tpy. The cost effectiveness would therefore be $45,520 per ton.

For the 1500 kW systems, with an estimated total capital investment of $22,500, the annualized cost was estimated to be $4,974 per engine. Given an annual uncontrolled emission rate of 0.13 tpy, the removal of PM was determined to be 0.113 tpy. The cost effectiveness would therefore be $44,210 per ton.

For the 168 kW systems, with an estimated total capital investment of $4,000, the annualized cost was estimated to be $848 per engine. Given an annual uncontrolled emission rate of 0.013 tpy, the removal of PM was determined to be 0.0113 tpy. The cost effectiveness would therefore be $75,394 per ton.

For the 75 kW systems, with an estimated total capital investment of $4,000, the annualized cost was estimated to be $814 per engine. Given an annual uncontrolled emission rate of 0.018 tpy, the removal of PM was determined to be 0.016 tpy. The cost effectiveness would therefore be $51,697 per ton.

Based on these cost estimates, Southern Nuclear determined that add-on control technology was not cost-effective for any of the engines and that use of the three other control techniques, which it had already proposed, is BACT. Because actual non-emergency operation of the engines is no more than 50 hours per year (1/10 of the 500 hours per year for which the cost analysis was done), EPD is convinced that the control of PM removal using add-on control technologies is not cost effective and that use of the three other control techniques is BACT.

CO and VOC

Southern Nuclear combined the CO and VOC BACT review, since the only add-on control available is effective in controlling both. They included the following possible control techniques for both CO and VOC:

- Combustion Process Design
- Catalytic Oxidation

Non-Selective Catalytic Reduction (3-Way Catalyst) was determined by Southern Nuclear and Miratech to be technologically infeasible for diesel engines. 3-Way catalyst can only be used on engine exhaust that contains <0.5 % Oxygen (less than 1/2 percent). By the nature of engine combustion, this can only be accommodated on some natural gas and most gasoline engines. When diesel fuel combusts, there must always be 6-10% Oxygen present so it would not be a candidate for a 3-way catalyst (NSCR), so only SCR can be used for NOx reduction. Natural Gas engines that are "Lean Burn", as produced from the factory, also contains about the same percentage oxygen, so that is why there will sometimes be SCR on a Lean Burn gas engine.

Both technologies were determined to be available and technically feasible, although Southern Nuclear noted that, “Based on a review of the RBLC database, no diesel engines were identified as using oxidation catalysts for the control of VOC.” However, Southern Nuclear determined that, if an oxidation catalyst were available, the best control would result if both control techniques were used. This was assumed to yield 90% control for CO and 50% control for VOC.

For the 5,560 kW systems, with an estimated total capital investment of $188,484, the annualized cost was estimated to be $39,120 per engine. Given an annual uncontrolled emission rate of 9.5 tpy CO and 0.93 tpy VOC, the removal was determined to be 90 tpy. The cost effectiveness would therefore be $4,330 per ton.

For the 1500 kW systems, with an estimated total capital investment of $50,850, the annualized cost was estimated to be $10,554 per engine. Given an annual uncontrolled emission rate 2.9 tpy CO and 0.28 tpy VOC, the removal was determined to be 2.7 tpy. The cost effectiveness would therefore be $3,905 per ton.

For the 168 kW systems, with an estimated total capital investment of $5,695, the annualized cost was estimated to be $1,182 per engine. Given an annual uncontrolled emission rate of 0.13 tpy CO 0.03 and tpy VOC. the removal was determined to be 0.13 tpy. The cost effectiveness would therefore be $8,805 per ton.

For the 75 kW systems, with an estimated total capital investment of $4,000, the annualized cost was estimated to be $814 per engine. Given an annual uncontrolled emission rate of 0.21 tpy CO 0.03 tpy VOC, the removal was determined to be 0.20 tpy. The cost effectiveness would therefore be $4,037 per ton.

Based on these cost estimates, Southern Nuclear determined that add-on control technology was not cost-effective for any of the engines and that use of the other control technique, which it had already proposed, is BACT. As with the other pollutants, because actual non-emergency operation of the engines occurs for no more than 50 hours per year (1/10 of the 500 hours per year for which the cost analysis was done), EPD is convinced that the control of CO or VOC using add-on controls is not cost effective and that use of the other control techniques is BACT.

Comment 2

On January 22, 2010, EPA signed into law a new National Ambient Air Quality Standard (NAAQS) for nitrogen dioxide (NO_2). The new standard is a 1-hour standard set at the level of 100 parts per billion (ppb). The effective date of the new NAAQS will be April 12, 2010. If the final PSD permit for the Vogtle Electric Generating Plant has not been issued by the time the new NAAQS is effective, the Division will need to include the appropriate air quality analysis before a final PSD permit is issued.

EPD Response:

The Division understands that if the permit is not issued before April 12, 2010, the 1-hour NO2 NAAQS must be addressed in the Final Determination.

Comment 3

In reviewing the draft permit and preliminary determination, Region 4 finds that the permitting authority has not provided an adequate rationale to support the use of the PM10 surrogate approach for this project. The preliminary determination should contain an analysis as to whether or not PM10 is a reasonable surrogate for PM2.5 under the facts and circumstances of the specific project at issue and not proceed with the general presumption that PM10 is always a reasonable surrogate for PM2.5. At this time the best example we have for completing a PM2.5 analysis is the one done for Louisville Gas and Electric in Kentucky. I have attached it for your reference. In addition, please find attached the Memorandum from Steve Page issued on March 23, 2010 *Modeling Procedures for Demonstrating Compliance with PM2.5 NAAQS. NOTE- No public comments regarding PM2.5 surrogacy were received from the general public.*

EPD Response:

Southern Nuclear – Plant Vogtle has now accepted permit conditions limiting PM2.5 emissions from this project to less than the PSD significance threshold of 10 tons per year. Thus, no review of PM2.5 BACT or ambient air impact is required. As such, there is no longer a need to demonstrate the reasonableness of using the PM10 Surrogate Policy.

There are two types of sources of stack emissions of PM2.5 in this project. These are cooling towers and engines.

The cooling towers will be assumed to operate at all times. The drift loss rate of the large cooling towers is limited to 0.0005% or less by the permit. The drift loss rate of the small cooling towers is limited to 0.005% or less by the permit. The Division has calculated PM2.5 emissions from the cooling towers, based on these drift losses, using the method described in the document authored by Joe Reisman and Gordon Frisbie entitled "Calculating Realistic PM10 Emissions from Cooling Towers". Using this method, the Division has determined that PM2.5 emissions from the larger cooling towers are about 0.3 percent of PM10 emissions and 0.6 percent of PM10 emissions from the smaller cooling towers. In order to assure that the permit limits are conservative, a safety factor of an order of magnitude has been added to each, so PM2.5 emissions are assumed to be 3 percent of PM10 from the large cooling towers and 6 percent of PM10 from the smaller cooling towers. This results in an annual emission rate of 0.52 tons per year from the cooling towers.

As already indicated, the engines will operate, on average, much less than year-round. Unlike the cooling towers, the emissions of PM2.5 are assumed to be 100 percent of the PM and PM10. Each of these engines is subject to a BACT PM limit that is in the permit. Per the explanation above, the emissions of PM2.5 is assumed to be emitted at the allowable PM rate in the permit. As agreed to by Southern

Nuclear, the Division is setting an allowable rate of PM emissions from the engines which is less than 10.0 tons per year, less the emission rate of PM2.5 from the cooling towers, which is 0.52 tons per year (7.9 tpy x 2 towers x 3% + 0.35 tpy x 2 towers x 6%). The engines are therefore limited to a total of 9.48 tons PM per year. Conditions have therefore been added to the permit to assure that. These require that the facility determine the hours of operation of each engine, multiply it by the applicable BACT PM emission limit (in g/kw-hr), and by the rated capacity (in kw) to determine PM emissions on a monthly basis. The totals for each 12 consecutive month period are then added together. Each 12-month total must be less than 9.48 tons PM. These conditions are shown below:

3.3.16 The Permittee shall ensure emissions of PM2.5 from the Standby Generators (Source Codes: VD05 through VD08), the RWS Standby Generator (Source Code: ODG1), the TSC Standby Generator (Source Code: ODG2), the Ancillary Generators (Source Codes: AUX1 through AUX4), and the Emergency Fire Pumps (Source Codes: FPD3 through FPD5), combined are less than 9.48 tons per 12-consecutive months.

5.2.5 The Permittee shall install a non-resettable hour meter on the Standby Generators (Source Codes: VD05 through VD08), the RWS Standby Generator (Source Code: ODG1), the TSC Standby Generator (Source Code: ODG2), the Ancillary Generators (Source Codes: AUX1 through AUX4), and the Emergency Fire Pumps (Source Codes: FPD3 through FPD5 and record the number of hours of operation for each diesel-fired engine each calendar month.

6.1.9 For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition 6.1.4, the following excess emissions, exceedances, and excursions shall be reported:

b. Exceedances: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) do not meet the applicable emission limitation or standard consistent with the averaging period specified for averaging the results of the monitoring)

iii. Any 12-consecutive month PM2.5 emissions determined in accordance with Condition 6.2.9 that equals or exceeds 9.48 tons.

6.2.8 The Permittee shall use the operating time for the Standby Generators (Source Codes: VD05 through VD08), the RWS Standby Generator (Source Code: ODG1), the TSC Standby Generator (Source Code: ODG2), the Ancillary Generators (Source Codes: AUX1 through AUX4), and the Emergency Fire Pumps (Source Codes: FPD3 through FPD5 recorded in accordance with Condition 5.2.5, the rated capacity for each engine (in kW), and the emission limits for particulate matter in Conditions 3.3.7, 3.3.8, and 3.3.9 to calculate the PM2.5 emissions for each calendar month using the following equation:

$$Monthly\ PM_{2.5}\ Emissions = \frac{\sum_{i=1}^{13}(EL_i)(Hr_i)(RC_i)}{(453.6)(2000)}$$

Where:

EL_i = The PM limit from Condition 3.3.7, 3.3.8, or 3.3.9, as applicable, for the ith engine (g/kW-hr).
Hr_i = The total operating hours for the ith engine (hr).

RC_i = The Rated Capacity of the ith engine from engine manufacturer (kW).
i = Diesel-fired engine (13 total).
453.6 = Conversion factor for grams to pounds.
2000 = Conversion factor for pounds to tons.

6.2.9 The Permittee shall use the monthly PM2.5 emissions determined in Condition 6.2.8 to calculate the 12-consecutive month total PM2.5 emissions for each calendar month. All the calculations shall be kept as part of the records required in Condition 6.2.8. The Permittee shall notify the Division in writing within 15 days if any 12-consecutive month total PM2.5 emissions equals or exceeds 9.48 tons. This notification shall include an explanation of how the Permittee intends to attain future compliance with Condition 3.3.16. A 12-consecutive month total shall be defined as the sum of a calendar month's total plus the totals for the previous eleven (11) consecutive months.

PLANT VOGTLE COMMENTS

Comments were received from T. C. Moorer, Manager – Environmental Affairs, Chemistry, and Radiological Services, by letter on April 6, 2010.

Comment 1

Southern Nuclear Operating Company (SNC) requests that the testing and monitoring requirements for the ancillary generators and fire pump engines be consistent with 40 C.F.R. 60 Subpart IIII.

Permit Condition 4.2.2 requires SNC to conduct an initial compliance test for the ancillary generators and fire pump engines. Additionally, Permit Conditions 4.2.6 and 5.2.3 require SNC to develop and implement a monitoring plan for those engines. However, NSPS Subpart IIII only imposes such requirements on engines with a displacement of greater than or equal to 30 liters per cylinder (see 40 C.F.R. 60.4204, and 60.4211). Since Subpart IIII also satisfies the requirements for 40 C.F.R. Part 63, Subpart ZZZZ for engines with a site rating of less than or equal to 500 brake horse power (see 40 C.F.R 63.6590), owners and operators of such engines with a displacement of less than 30 liters per cylinder need only ensure that the engines are certified to the relevant emissions standards by the manufacturer in order to comply with all applicable monitoring requirements. At this time, detailed information about this equipment is unknown and will not be available until final procurement decisions are made. SNC proposes the following mechanism to address this comment.

Although the ancillary generators and the fire pump engines should have a rating of less than or equal to 500 brake horse power, as noted in SNC's permit application, SNC has not yet determined whether the engines will have a displacement of greater than or equal to 30 liters per cylinder. If the engines have a displacement of less than 30 liters per cylinder, Subpart IIII would require the initial performance tests or monitoring plans imposed by Permit Conditions 4.2.2, 4.2.6, and 5.2.3. There is no reason to believe that the monitoring requirements of the NSPS would not be sufficient to demonstrate compliance with BACT limits in such event. Therefore, in recognition of the fact that those requirements may potentially not apply to either the ancillary generators or the fire pump engines, the following phrase should be added to the end of Permit Conditions 4.2.2, 4.2.6, and 5.2.3 to ensure consistency with Subpart IIII:

> "This Condition shall not apply to any unit with a displacement of less than 30 liters per cylinder."

EPD Response:

The Division believes that a demonstration of compliance with the permit limits is needed. This demonstration is most accurately achieved through an emissions test. Since these limits are included as BACT, the Division does not believe that a manufacturer certification is sufficient. Additionally, the Division does not believe that monitoring parameters that indicate compliance is overly burdensome since incorporation of the monitoring system can be considered when selecting the engines to use.

Comment 2

SNC requests that the following changes be made to Table 6-4, 6-5, 6-6, 6-7, 6-8, and 6-9 of the PSD Preliminary Determination.

Based on the results of the air quality analysis submitted with the application, SNC requests the following changes for accuracy:

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

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	SIL (ug/m^3)	Significant?
NO_2	Annual	2006	427.100	3666.500	3.83	1	**Yes**
PM_{10}	24-hour	2006	426.700	3666.700	7.10	5	**Yes**
	Annual	2006	427.079	3666.550	0.52	1	No
CO	1-hour	2006	430.529	3667.071	~~1636.39~~ 1636.10	2000	No
	8-hour	2006	~~430.700~~ 426.700	3666.700	~~400.46~~ 400.18	500	No

Table 6-5: NAAQS Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Background (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
NO_2	Annual	2006	429.723	3667.824	~~7.01~~ 6.98	14	~~21.01~~ 20.98	100	No
PM_{10}	24-hour	2006	~~428.655~~ 429.481	~~3665.280~~ 3668.162	~~25.03~~ 23.82	38	~~63.03~~ 61.82	150	No
	~~Annual~~	~~2006~~	~~429.659~~	~~3667.898~~	~~4.06~~	~~20~~	~~24.06~~	~~50~~	~~No~~

Table 6-6: Increment Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
NO_2	Annual	2006	~~429.723~~ 427.100	~~3667.824~~ 3666.500	~~4.50~~ 4.04	25	No
PM_{10}	24-hour	2006	~~429.481~~ 426.700	~~3668.162~~ 3666.700	~~23.92~~ 7.21	30	No
	~~Annual~~	~~2006~~	~~429.659~~	~~3667.898~~	~~3.30~~	~~17~~	~~No~~

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

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
NO_2	Annual	2006	427.100	3666.500	14	3.83	No
PM_{10}	24-hour	2006	426.700	3666.700	10	7.10	No
CO	8-hour	2006	426.700	3666.700	575	~~400.46~~ 400.18	No

Table 6-8: Class I Significance Analysis Results – Cape Romain Wilderness Area

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Projected Concentration (ug/m^3)	Significance Level (ug/m^3)	Significant?
NO_2	Annual	~~2006~~ 2002	~~478.096~~ 1609.918	~~3664.505~~ -633.619	~~0.033~~ 4.48E-04	0.1	No
PM_{10}	24-hour	~~2006~~ 2003	~~426.700~~ 1610.154	~~3663.459~~ -630.742	~~0.224~~ 1.12E-02	0.3	No
	Annual	~~2006~~ 2002	~~478.034~~ 1610.214	~~3663.459~~ -626.955	~~0.011~~ 4.44E-04	0.2	No

Table 6-9: Class I Significance Analysis Results – Wolf Island Wilderness Area

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Projected Concentration (ug/m^3)	Significance Level (ug/m^3)	Significant?
NO_2	Annual	~~2006~~ 2002	~~441.096~~ 1485.848	~~3618.651~~ -828.138	~~0.019~~ 2.23E-04	0.1	No
PM_{10}	24-hour	~~2006~~ 2003	~~438.038~~ 1489.135	~~3617.934~~ -828.508	~~0.085~~ 3.95E-03	0.3	No
	Annual	~~2006~~ 2002	~~437.010~~ 1485.848	~~3617.737~~ -828.138	~~0.006~~ 2.29E-04	0.2	No

EPD Response:

The Division reviewed the request corrections and found that most of the information presented in the Preliminary Determination matches the Division's modeling results. The Division did find some errors in the Preliminary Determination. In Table 6-4, the 8-hour CO UTM East should have been 426.700. In Tables 6-5 and 6-6, the Annual PM10 NAAQS Analysis Results and Increment Analysis Results should not have been included. The annual PM10 impact was less than the significant impact level, and the refined model should not have been conducted for this averaging time. In Table 6-8, the 24-hour PM UTM East should have been 478.034. Note that the Division is including this information in the Final Determination and not reissuing the Preliminary Determination to include corrections.

<u>Editorial Comments</u>

In addition to the official comments from SNC, the following informal "editorial" comments on the Preliminary Determination were received from Dale Fulton, Environmental Specialist – Environmental Affairs, by email April 5, 2010.

A. Page 10, "The PM limits proposed by Plant Vogtle and in this permit are consistent with the lowest emission limits for CO." "PM" should be CO.

B. Page 10, "The PM limits proposed by Plant Vogtle and in this permit are consistent with lowest emission limits for VOC." "PM" should be VOC.

C. Page 11, "The PM limits proposed by Plant Vogtle and in this permit are consistent with lowest emission limits for NOx." "PM" should be NOx.

D. Page 12, First paragraph, last sentence: Delete "drops".

E. Page 13, Third paragraph, first sentence: Delete "for"

F. Page 19, Second paragraph, last sentence: change "three" to two.

EPD Response:

Each of the editorial comments is correct. The Preliminary Determination should have read as suggested in this comment. As noted above, however, the Division is noting this in the Final Determination and is not reissuing the Preliminary Determination.

ALEX J. SAGADY & ASSOCIATES COMMENTS

Comments were received from Alex J. Sagady & Associates on behalf of the Augusta Building & Construction Trades Council by email on July 10, 2009. These comments were submitted in response to the Public Advisory issued for the week of June 8, 2009 (PA0609-2) and were considered in the draft permit. Only comments directly impacting the permit or the permitting process are included below. The complete comments are included in Appendix B of the Final Determination. Comment 1 only identified the commenter and is therefore needed no response.

Comment 2

Request to be Notified in Writing of the Future PSD Public Notice

EPD Response:

The Division notified Mr. Sagady by email on March 11, 2010, that the draft permit and other relevant documents (e.g., Preliminary Determination, Public Notice) were available on the Air Protection Branch website (www.georgiaair.org). Another email was sent on March 15, 2010, clarifying that a public notice also included a notice of a public hearing. Mr. Sagady responded to each email the same day.

Comment 3

Commentor's Request for a Public Hearing

By this letter, the Council requests a Georgia Air Protection Branch public hearing be held regarding this facility. The Council requests that a public hearing be held in association with a future public notice, draft permit and comment period announcement concerning this facility at a location near the proposed facility.

EPD Response:

The Division held a public hearing at 6:30 PM on April 6, 2010 at the Augusta Technical College, Waynesboro Campus Auditorium, 216 Highway 24 South, Waynesboro, Georgia 30830.

Comment 4.1

The Best Available Control Technology (BACT) Demonstration Submitted by the Applicant Fails to Conform to EPA's "Top Down" BACT Determination Process Notwithstanding Applicant's Claims that it Carried Out Such a Determination

EPD Response:

The Division agrees that the BACT analysis originally submitted by Plant Vogtle did not sufficiently document the "top down" process. The Division requested that Plant Vogtle document the "top down" process more fully. Plant Vogtle submitted a revised BACT analysis, which included a "top down" analysis, by letter dated September 11, 2009. This BACT analysis is reviewed in the section of this Final Determination devoted to responding to comments by EPA Region 4.

Comment 4.2

An Allowable Opacity of 40% is Not BACT for Visible Emissions from the Proposed Combustion Units

EPD Response:

The Division does not agree that a BACT limit for visible emissions is required. Visible emissions from stationary internal combustion engines are nearly zero. The 40% opacity permit limit for these sources is due to Georgia Rule 391-3-1-.02(2)(b), which is applicable when no other opacity limit exists. Since no other rules (including 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ) limit visible emissions from these engines, the opacity limit for the diesel-fired engines is 40%. In the early days of PSD, opacity may have served as a good indicator of compliance with the selected BACT standard, and may still be used as a BACT limit when particulate matter emissions are impractical (such as for fugitive dust sources).

Comment 4.3

Condensable Particle Emissions at the Proposed Facility are Not Automatically Deregulated Under EPA's Revisions to New Source Review Requirements

EPD Response:

The Division agrees that condensable PM should be regulated by this permit. Consequently, the compliance determination method for the PM limits from the diesel-fired engines is Georgia Method 5T (see Condition 4.1.3o). This method includes both "front-half" (filterable PM) and "back-half" (condensable PM) catches for determining PM concentrations.

Comment 4.4

Excluding Condensable PM Emissions from PM-10 related Air Quality Impact Analysis is an Improper Air Quality Modeling Practice

EPD Response:

The modeling for PM10 used the PM emission limits. Because these limits are for total PM emissions (see EPD Response to Comment 4.3), the modeling analysis does include condensable PM emissions.

Comment 4.5

The Applicant Should be Required to Perform PM2.5 Modeling

EPD Response:

As explained above, modeling for PM2.5 is not required since the permit will contain PM2.5 major source avoidance conditions.

Comment 4.6

Applicant's Submittal Contained No Rendition of Contemporaneous Increases and Decreases in the Overall Project Emissions Calculus and Air Quality Modeling Analysis

EPD Response:

The Division agrees that for air quality modeling, contemporaneous increases and decreases should be included. The Division was able to identify two projects at Plant Vogtle in the contemporaneous period; a temporary boiler permitted September 28, 2006, and a temporary boiler permitted March 21, 2007. Each of these temporary boilers has since been removed; therefore, the contemporaneous increases are paired with equally large contemporaneous decreases. Although the complete netting process is not documented in either the permit application or the Preliminary Determination, the net result is the same for modeling purposes. If, however, the commenter is referring to the Shaw Group, Inc. permit issued June 18, 2009 (and amended December 29, 2009), the Division has determined that this project is not at the same PSD site and should not be considered in a netting analysis. As with the temporary boilers, the Shaw Group and its emissions will be removed from the site prior to the startup of the equipment in this application. Furthermore, while Shaw will provide construction work, they will not support the operation of Vogtle.

Comment 4.7

Applicant Should Install Continuous Opacity Monitors

EPD Response:

The Division disagrees that Continuous Opacity Monitors are needed. The opacity limit from these engines is 40%, but the expected opacity level is nearly zero (see response to Comment 4.2). With this expected level of compliance, opacity monitoring is unnecessary. The permit does require continuous monitoring of parameters linked to the pollutants regulated in the permit. The Division believes that this approach will assure compliance with the emission limits better than monitoring opacity.

Comment 4.8

The Applicant has Failed to Include Site Roads and Ongoing Construction Activities as Site Emission Units

EPD Response:

The Division disagrees that road emissions need to be included. The road emissions will be minimal and, therefore, are not necessary to include as an emission unit. The nature of the operations at Plant Vogtle will entail infrequent shipments to and from the site. Additionally, all roads on the site will be paved, resulting in a very low emission rate.

The Division also disagrees that ongoing construction emissions should be included for the following three reasons: Construction emissions are not regulated by the federal PSD regulations (40 CFR 52.21). Georgia has a SIP-approved PSD program that has not incorporated construction emissions as a required emissions unit. And Georgia historically has not regulated emissions from ongoing construction activities.

Comment 4.9

Nuclear Plant Equipment that Emits Airborne Radionuclides Should Be Addressed in the Application as Emission Units

EPD Response:

As stated in the Preliminary Determination, the nuclear units are subject to review and licensing by the U.S. Nuclear Regulatory Commission (NRC) and not by the Georgia Environmental Protection Division in accordance with the federal and state Clean Air Acts. The Clean Air Act does not give the Division the legal authority to regulate the equipment at Plant Vogtle that could possibly emit radionuclides.

Comment 4.10.1

Applicant's BACT Analysis Failed to Properly Justify Reliance on a 0.005 % Drift Elimination Efficiency

EPD Response:

While the applicant's analysis was brief, the Division believes that the 0.005% drift loss rate represents BACT for the Service Water Cooling Towers (which are fairly insignificant in comparison to the much larger circulating water towers). In any case, since the potential to emit PM from each of these cooling towers is only 0.35 tons per year, any increase in the drift elimination efficiency would have a very small impact on potential emissions.

Comment 4.10.2

Water Input Characterization for Circulating Water Cooling Towers

The Application should have provided a copy of the study characterizing the total dissolved solids concentration of the river water used for the circulating water towers. The Application should be required to monitor this parameter.

It is technically feasible to reduce total dissolve solids concentrations in the river water withdrawn for use at the site. Such water pretreatment must be considered in any BACT review for circulating water cooling tower PM emissions characterization and emission limitation.

EPD Response:

Upon EPD's request, Plant Vogtle submitted a copy of the study "Savannah River at Risk" published by the Southeastern Natural Sciences Academy. This study is mentioned in the application as the source of total dissolved solids (TDS) concentration in Savannah River water. The study does not contain the data for each sample collected, but, instead, summarizes the results. Out of 22 total samples taken at River Mile 148 (approximately one mile downstream of Plant Vogtle), the highest reading was 150, the lowest reading was 39, the mean was 71.41, and the median was 67.5 (all measurements are in units of mg/L).

The Division checked entries in the RACT/BACT/LAER Clearinghouse (RBLC) that included a listing of a process description containing the phrase "cooling tower". There were 29 such entries since January 1, 2008. Only three entries contained limits on dissolved solids and these were all permits issued by the Clark County Department of Air Quality and Environmental Management. None of the 29 entries

mentioned water pretreatment to reduce TDS. Therefore, the Division does not agree that pretreatment is necessary.

The Division, however, has reconsidered requiring the monitoring of TDS in the Circulating Water Cooling Towers, in order to assure that the results of computer modeling of particulate matter remains valid. Based on the data supplied in the above mentioned study, the maximum TDS in river water is 150 mg/L. Plant Vogtle assumed that, given recycling of the water and their water replacement schedule, the amount of solids could not accumulate to more than 8 times the incoming concentration while in the cooling tower loop, for a total maximum concentration in the cooling water of 1,200 mg/lb. Based on this data, Plant Vogtle estimated that each cooling tower will have the potential to emit (PTE) PM of 1.8 lb/hr. Section 3.1.2.1 of the application states, "Normally, the cooling towers are operated at four cycles of concentration." Therefore, the Division believes that the actual emissions from these cooling towers will be no more that half of the PTE. The air quality modeling, however, was even more conservative. It used an erroneously high emission rate from these cooling towers of 7.2 lb/hr from each cooling tower (four times the actual PTE). EPD is very sure that the PM emissions actually emitted by the cooling towers could never exceed what was modeled. However, to assure that concentrations remains low, monitoring is being required. For the monitoring, the Division is using, as a reporting trigger, the level of TDS relied upon in the modeling to show compliance with the NAAQS. That level is 4,800 mg/L (1,200 x 4).

Conditions 5.2.4 and 6.1.9c.i. have been added as follows for monitoring TDS.

5.2.4 The Permittee shall determine and record the total dissolved solids (TDS) content of the cooling water in the Circulating Water Cooling Towers (Source Codes: CWT1 and CWT2) using the following schedule. The determination of TDS shall be made using Standard Methods SM2540C, a TDS or conductivity meter, or another method approved in advance by the Division.

a. Measurements shall be made once each calendar quarter until four consecutive quarterly measurements are each less than 3,600 mg/L.

b. After four consecutive quarterly measurements are each less than 3,600 mg/L, measurements shall be made once each semiannual period until two consecutive semiannual measurements are each less than 3,600 mg/L.

c. After two consecutive semiannual measurements are each less than 3,600 mg/L, measurements shall be made once every two years (approximately 24 months apart).

6.1.9 For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition 6.1.4, the following excess emissions, exceedances, and excursions shall be reported:

c. Excursions: (means for the purpose of this Condition and Condition 6.1.4, any departure from an indicator range or value established for monitoring consistent with any averaging period specified for averaging the results of the monitoring)

i. Any measurement of TDS required by Condition 5.2.4 that exceeds 4,800 mg/L.

<u>Comment 4.11</u>

HAP Source Size Status Should be Clarified

EPD Response:

The While the Division did note the conflicting information regarding HAP emissions at this facility, the most conservative approach was taken with regards to rule applicability, which assumes that the site is major for HAPs. The diesel-fired engines are, therefore, subject to 40 CFR 63 Subpart ZZZZ.

OTHER PUBLIC COMMENTS

No Public comments were received in writing, with the exception of the following, which were submitted at the April 6, 2010 Public Hearing.

Comment received from Lou Zeller of Blue Ridge Environmental Defense League (delivered in person at the hearing on April 6, 2010. (Comment summarized as follows – for the actual text, see the Appendix.)

General Comment
EPD should not approve the permit.

Comment 1 - Vogtle will not meet NESHAP.

During normal operations, Vogtle emits radioactive pollution into the air. (Table 1 ranging from 18 to 5870 microcuries per year for years 1987 to 1993). The emissions included in Table 1 are radioactive isotopes which persist in the environment.

Table 2 lists gaseous emissions of nuclear fission and activation products. (Table 2 ranging totaling 28.34 curies for 4 years 2001-2004 for unit 1, 4.73 curies for unit 2). The majority of emissions are clustered into relatively brief time periods.

As you know, radionuclides are listed HAP. Specifically, Vogtle will not meet Clean Air Act Standards because:

1) without MACT, routine emissions from the plant would be excessive especially considered in addition to the existing site-wide radioactive emission levels.
2) company does not properly account for higher levels of morbidity and mortality in females and infants caused by low levels of radiation.

Enforcement of the Clean Air Act regulations related to nuclear plants are delegated to the NRC. EPD develops standards for major emitters of HAPs, but No MACT has been issued for radionuclides. Further, although emission rates from the cooling towers and other sources are measured, the millirem standard for maximum dosage to the public is an ambient standard, not an emission limit. Without ambient measurements, EPD cannot assure that radionuclide emissions are below the standard. At present, EPD cannot assure that Vogtle will meet NESHAP radionuclide emission limits.

EPD Response:

The commenter is correct that NRC is delegated authority for the reactors, and EPD has authority for the cooling towers and diesel engines. The commenter is also correct that radionuclides are one of the 187 listed HAPs. Applying conversion rate of 9611 Ci per gram, calculated for tritium using the procedure found on the website http://www.hps.org/publicinformation/ate/q2548.html, the total amount of radionuclides (38.34 curies), is roughly 0.004 grams for all four years from Vogtle Unit 1.

Adding together these values, plus the potential emissions of radionuclides from the proposed cooling towers, plus the HAP emissions from the 13 diesel generators yields a total HAP emissions of 1.6 tons per year for the project is expected.

EPA's MACT/NESHAP provisions are codified in 40 CFR 63.

40 CFR 63 Subpart 63 Subpart B (112(g) , which requires case-by-case assessment of MACT, applies to new/proposed major sources of HAP. The "Major Source" threshold is 10 tons per year of any single HAP or 25 tons per year of any combination of HAP. The proposed project will not be major for HAP and thus is not could not be subject to Subpart B.

40 CFR 63 (EPA's MACT or NESHAP standards) applies to the proposed diesel engines thru Area Source MACT 40 CFR 63 Subpart ZZZZ.

Comment 2 – Environmental Justice.

EPD must consider the impact the reactors will have on people in the area, a community already noted for higher-than-average cancer rates. One study shows higher cervical cancer in black women, and higher esophageal cancer in black men, in a 50 mile radius. This should be assessed. Executive Order 12898 requires federal agencies to address disproportionate human health effects of its policies, including greater public participation. GEPS is not a federal agency, but required to enforce the Clean Air Act as an Agreement State.

EPD Response:

As a SIP approved state agency, Federal executive orders do not apply to Georgia EPD. EPD does work to ensure that the public has access to the relevant information and by having a public hearing, as we did in this case, when requested.

Verbal Comments made by the Public at the Hearing

Lou Zeller
The permit should not be issued as written. Radioactive Tritium is water emitted from the cooling towers and these should be accounted for and assessed.

EPD Response:

Based on the worst-case water usage in the cooling towers, and applying a conversion rate of 9611 Ci per gram, calculated for tritium using the procedure found on the website http://www.hps.org/publicinformation/ate/q2548.html, the total amount of radionuclides that could be emitted from the cooling towers is 0.24 grams per year (2.78 E-7 tons per year).

Merv Waldron – Burke County Administrator
Supports the Vogtle expansion

EPD Response:

Comment so noted.

Ashley Roberts- Chamber of Commerce
Supports the Vogtle expansion

EPD Response:

Comment so noted.

Janet Marsh – Blue Ridge Environmental Defense League
EPD should conduct an analysis to determine the cumulative impacts of the emissions in the area. Who knows what level of benzene or carbon monoxide will be the "last straw"

EPD Response:

EPD has a network of ambient monitors located throughout the state to measure the concentrations of criteria pollutants to assess for compliance with the National Ambient Air Quality Standards (NAAQS). Based on data from these monitors, carbon monoxide concentrations are well in compliance with current NAAQS. GEPD also has ambient monitors for certain organic toxic emissions. Given the mostly rural nature of Burke County, EPD would not anticipate concentrations higher than those measured at our more urban ambient monitoring sites. EPD conducted analyses to ensure that the NAAQS are protected for the criteria pollutants and that the maximum expected levels of air toxics are in compliance with Georgia's Air Toxic Guideline. EPD also has ambient monitors for certain organic toxic emissions.

Claude Howell
I am totally opposed to the expansion. I have seen through the years cancer rates rise since Plant Vogtle was built.

EPD Response:

Comment so noted. EPD is not aware of any cancer clusters as identified by the Georgia Division of Public Health that are located in Burke County. Additional information may be obtained at the Division for Public Health's webpage: http://health.state.ga.us/programs/envservices/index.asp. Including cancer statistics to compare Burke County with every other county in Georgia. http://health.state.ga.us/pdfs/chronic/cancer/Inc0206.pdf

APPENDIX A

AIR QUALITY PERMIT

4911-033-0030-V-02-3

APPENDIX B

WRITTEN COMMENTS
RECEIVED DURING
COMMENT PERIOD