Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

December 16, 2019

Facility Name: Thomas A. Smith Energy Facility
City: Dalton
County: Murray
AIRS Number: 04-13-21300034
Application Number: TV-343540
Date Application Received: May 7, 2019

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

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Thomas A. Smith Energy Facility for a permit to make control system changes to increase the capacity of each Block 1 and Block 2 by approximately 28.6 MW in the summer and 31.0 MW in the winter, referred to as the Advance Gas Path (AGP) Project III. Contemporaneous to this project, Oglethorpe Power Corporation will also install new turbine components and controls to allow sustained operations at lower operating loads, referred to as the Minimum Load Project.

The modification of the Thomas A. Smith Energy Facility due to the AGP Project III will result in emissions increases in SO_2, CO, VOC, H_2SO_4, filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e). A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any increase was above the "significance" level. The PM, PM_{10}, $PM_{2.5}$, NOx, and GHG emissions increases were above the PSD significant level thresholds.

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

The EPD review of the data submitted by Thomas A. Smith Energy Facility related to the proposed modifications indicates that the project will comply with all applicable state and federal air quality regulations.

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

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 200 km of the facility.

It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Thomas A. Smith Energy Facility for the modifications necessary to make control system changes to increase the capacity of each Block 1 (CT1 and CT2) and Block 2 (CT3 and CT4) by approximately 28.6 MW in the summer, and 31.0 MW in the winter, referred to as the AGP Project III. The facility is also installing new turbine components, and controls to allow sustained operations at lower operating loads, referred to as the Minimum Load Project. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A. This Preliminary Determination also acts as a narrative for the Title V Permit.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On May 7, 2019, Thomas A. Smith Energy Facility (hereafter OPC T.A. Smith) submitted an application for an air quality permit to make control system changes to increase the capacity of Block 1 (CT1 and CT2), and Block 2 (CT3 and CT4) by approximately 28.6 MW in the summer, and 31.0 MW in the winter, referred to as the AGP Project III. Post project capacity of the facility will be 1,302 MW with each combustion turbine having a heat input of 1,859 MMBtu/hr. and each duct burner having a heat input of 578 MMBtu/hr. The facility is also installing new turbine components and controls to allow sustained operations at lower operating loads, referred to as the Minimum Load Project. The facility is located at 925 Loopers Bridge Road in Dalton, Murray County.

Table 1-1: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	Y	✓		
PM_{10}	Y	✓		
$PM_{2.5}$	Y	✓		
SO_2	Y			✓
VOC	Y	✓		
NO_x	Y	✓		
CO	Y	✓		
TRS	N/A			
H_2SO_4	Y			✓
Individual HAP	Y			✓
Total HAPs	Y			✓
Total GHGs	Y	✓		

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

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

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-213-0034-V-08-0	January 4, 2016	Title V Permit Renewal
4911-213-0034-V-08-1	March 28, 2017	Additional time for startup of the turbines during limited testing for regulatory and post-maintenance operation.
4911-213-0034-V-08-2	October 3, 2018	Acid Rain Permit Renewal

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

Table 1-3: Emissions Increases from the Project

Pollutant	Baseline Years	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	April 2011 - March 2013	153.32	25	Yes
PM_{10}	April 2011 - March 2013	153.32	15	Yes
$PM_{2.5}$	April 2011 - March 2013	153.32	10	Yes
VOC	April 2011 - March 2013	36.02	40	No
NO_X	April 2011 - March 2013	127.50	40	Yes
CO	April 2011 - March 2013	47.49	100	No
SO_2	April 2011 - March 2013	14.52	40	No
H_2SO_4	April 2011 - March 2013	2.43	7	No
CO_2e	April 2011 - March 2013	2,897,635	75,000	Yes

For existing electric utility steam generating units, the definition of baseline actual emissions is the average emission rate, in tons per year, at which the emission unit actually emitted the pollutant during any consecutive 24-month period selected by the facility within the 5-year period immediately preceding the date a complete permit application was received by EPD. The net increases were calculated by subtracting the past actual emissions (based upon the annual average emissions from April 2011 – March 2013) from the future projected actual emissions of the Block 1 (CT1 and CT2) and Block 2 (CT3 and CT4), and associated emission increases from non-modified equipment. The Division requested a 5 year look back period for baseline actual emissions from AGP Project 1 (which occurred in 2014). This is highly conservative, since the overall facility utilization was much lower prior to 2014 than in recent years as a result of significant decreases in natural gas prices since 2014, leading to lower facility wide actual emissions for a baseline period occurring prior to 2014. Table 1-4 details this emissions summary. The emissions calculations for Tables 1-3 and 1-4 can be found in detail in the facility's PSD application (see Appendix B of Application No. TV-343540).

Projected actual emissions are the maximum projected annual emission rates from 2018-2027. Demand Growth Emissions are calculated by taking the emissions that could have been accommodated (during the selected baseline period) less the baseline emissions. Baseline to Projected Actual Emissions are calculated by taking the projected actual emission less the baseline emissions and demand growth emissions. It is conservatively assumed that PM = Total PM_{10} = Total $PM_{2.5}$. NSR permitting can only be triggered for CO_2e if the baseline to projected actual emissions increase is greater than the NSR major modification threshold for another criteria pollutant and CO_2e. CO_2e cannot trigger NSR permitting on its own. CO_2 is scaled to CO_2e: CO_2 Baseline Actual Emissions (tpy)*[(CO_2EF (lb/MMBtu) * 1 (GWP) + CH_4EF (lb/MMBtu) * 25 (GWP) + N_2O EF (lb/MMBtu) * 298 (GWP) / [(CO_2EF (lb/MMBtu) * 1 (GWP)]. These calculations have been reviewed and approved by the Division.

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

Pollutant	Increase from Modified Equipment		Emissions that Could Have Been Accommodated (tpy)	Demand Growth Emissions (tpy)	Baseline to Projected Actual Emissions Increase (tpy)	NSR Major Modification Threshold (tpy)
	Baseline Actual Emissions (tpy)	Projected Actual Emissions (tpy)				
PM	86.00	269.01	115.69	29.69	153.32	25
PM_{10}	86.00	269.01	115.69	29.69	153.32	15
$PM_{2.5}$	86.00	269.01	115.69	29.69	153.32	10
VOC	20.20	63.20	27.18	6.98	36.02	40
NO_X	146.20	309.30	181.80	35.60	127.50	40
CO	304.05	597.80	550.31	246.26	47.49	100
SO_2	8.10	25.62	11.10	3.00	14.52	40
CO_2e	1,636,005	5,080,359	2,182,724	546,719	2,897,635	75,000
H_2SO_4	1.37	4.27	1.84	0.47	2.43	7

Based on the information presented in Tables 1-3 and 1-4 above, OPC T.A. Smith's proposed modification, as specified per Georgia Air Quality Application No. TV-343540, is classified as a major modification under PSD because the potential emissions of filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e) exceed the NSR Major Modification Thresholds.

Through its new source review procedure, EPD has evaluated OPC T.A. Smith's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

According to Application No. TV-343540, OPC T.A. Smith has proposed to make control system changes that would allow the facility to increase the capacity of each block by approximately 28.6 in the summer and 31.0 MW in the winter (Block 1 being CCCT1 and CCCT2 and steam turbine, and Block 2 being CCCT3 and CCCT4 and steam turbine), referred to as the AGP Project III. These control changes would result in an associated increase in maximum heat inputs and maximum hourly rate of emissions when the duct burners are used at their full capability. OPC is also considering installation of new turbine components and controls to allow sustained operation at lower operating loads, referred to as the Minimum Load Project. Currently, OPC T.A. Smith's Title V permit only allows turbine operation below 73.6 MW during periods of startup, shutdown, or special testing (Permit Condition No. 3.3.7). This value was selected based on GE-provided data indicating an increase in NOx and CO emissions concentrations at lower loads potentially exceeding the facility's emission limits for those pollutants. The Minimum Load Project, if implemented, would allow the gas turbines to operate at a lower minimum load while continuing to maintain NOx and CO emissions concentrations in compliance with the facility's permitted emission limits.

The OPC T.A. Smith permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at;
https://epd.georgia.gov/psd112gnaa-nsrpcp-permits-database.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

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

Visible Emissions - GRAQC 391-3-1-.02(2)(b)

Rule (b) limits the visible emissions from any emissions source not subject to some other visible emissions limitation under GRAQC 391-3-1-.02 to 40% opacity. Visible emissions testing may be required at the discretion of the Director. The combustion turbines at OPC T.A. Smith are subject to this regulation. The duct burners are subject to more stringent visible emissions standards through Rule 391-3-1-.02(2)(d) and are, therefore, not subject to Rule (b).

The turbines fire pipeline-quality natural gas with emissions exhibiting minimal opacity; the firing of clean fuels in conjunction with proper operation ensures compliance with this rule. No applicable requirements per Rule (b) will be altered as a result of the proposed projects. The facility will continue to comply with this opacity requirement as currently outlined in the existing Title V permit. [Current Title V Permit Condition 3.4.1]

Fuel Burning Equipment - GRAQC 391-3-1-.02(2)(d)

Rule (d) limits the PM emissions, visible emissions, and NO_X emissions from fuel-burning equipment. The standards are applied based on installation date, the heat input capacity of the unit, and the fuel(s) combusted.

The GRAQC define "fuel-burning equipment" as follows:[1]

> *"Fuel-burning equipment" means equipment the primary purpose of which is the production of thermal energy from the combustion of any fuel. Such equipment is generally that used for, but not limited to, heating water, generating or super heating steam, heating air as in warm air furnaces, furnishing process heat indirectly, through transfer by fluids or transmissions through process vessel walls."*

The combustion turbines are used for the generation of electric power, not the production of thermal energy. Therefore, they do not meet the definition of fuel burning equipment. The duct burners do, however, meet this definition and are therefore subject to this rule.

The duct burners were installed or modified after January 1, 1972, making them subject to the PM standards for new units under 391-3-1-.02(2)(d)2. Since each duct burner has a heat input capacity

[1] GRAQC 391-3-1-.01(cc)

exceeding 250 MMBtu/hr, each duct burner has a PM emission limit of 0.10 lb/MMBtu.[2] This limit will not change once the proposed modification is complete. The PM emission limits for the duct burners are subsumed by the more stringent PM emission limit found in Condition 3.3.2.c of the current operating permit and will be subsumed by the proposed BACT limit.

All fuel-burning equipment constructed after January 1, 1972 is subject to a visible emissions limit of 20% except for one six-minute period per hour of not more than 27% opacity. This limit applies to the duct burners.[3] The opacity limit will not change once the propose modification is complete. The opacity limitation for the duct burners is subsumed by the more stringent opacity limitation given in Condition 3.3.2.e of the current operating permit.

Lastly, fuel-burning equipment that has a heat input capacity greater than 250 MMBtu/hr; that was constructed after January 1, 1972; and that combusts coal, oil, or gas is subject to a NO_X emission limit. Since the duct burners are gas-fired units, they are subject to a NO_X emission limitation of 0.2 lb/MMBtu.[4] The NO_X emission limit will not change once the proposed modification is complete. This limit is subsumed by the more stringent NO_X BACT limitation for the combustion turbines/duct burners.

<u>Particulate Emissions from Manufacturing Processes - GRAQC 391-3-1-.02(2)(e)</u>

Rule (e), commonly known as the process weight rule, establishes PM limits where not elsewhere specified. As the duct burners are fuel-burning equipment, they are subject to a separate particulate limit per Rule (d).

Combustion turbines are not technically subject to Rule (d), and historically have not been regulated by Rule (e). Therefore, the combustion turbines and duct burners at OPC T.A. Smith are not subject to this regulation.

<u>Sulfur Dioxide - GRAQC 391-3-1-.02(2)(g)</u>

Rule (g) limits the maximum sulfur content of any fuel combusted in a fuel-burning source, based on the heat input capacity. As this rule applies to fuel-burning sources, not “fuel-burning equipment,” this regulation presently applies to the combustion turbines and duct burners. For the duct burners and turbines, which have heat input capacities greater than 100 MMBtu/hr, the fuel sulfur content is limited to not more than 3% by weight.[5] The proposed projects do not alter the applicable requirements of Rule (g), and OPC T.A. Smith will continue to comply with Rule (g). This limit is subsumed by the more stringent fuel sulfur limit under NSPS Subpart KKKK.

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[2] GRAQC 391-3-1-.02(2)(d)2(iii)

[3] GRAQC 391-3-1-.02(2)(d)3

[4] GRAQC 391-3-1-.02(2)(d)4(iii)

[5] GRAQC 391-3-1-.02(2)(g)2

Fugitive Dust - GRAQC 391-3-1-.02(2)(n)

Rule (n) requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. OPC T.A. Smith will continue to take the appropriate precautions to prevent fugitive dust from becoming airborne for any applicable equipment.

VOC Emissions from Major Sources - GRAQC 391-3-1-.02(2)(tt)

Rule (tt) limits VOC emissions from facilities that are in or near the original Atlanta 1-hour ozone nonattainment area. OPC T.A. Smith is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[6]

Visibility Protection - GRAQC 391-3-1-.02(2)(uu)

Rule (uu) requires EPD to provide an analysis of a proposed major source or a major modification to an existing source's anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). The visibility-impacting pollutants include NO_X, PM_{10}, SO_2, and H_2SO_4. A screening analysis of federal Class I areas resulted in a Q/D value less than 10. Although one of the federal Class I areas (Cohutta) is within 50 km, special stipulation by the FLM indicated that since Q/D was less than 10 for Cohutta, no detailed Air Quality Related Values (AQRV) analysis (e.g., visibility) would be required. Therefore, a full review of the anticipated impact on visibility was not performed. Further documentation regarding an evaluation of impacts related to these projects on Class I areas, and further documentation referenced such as correspondence with the appropriate FLM, is provided in Volume II of the facility's PSD application (Application No. TV-343540).

The following Georgia State rules are not applicable since OPC T.A. Smith (which is located in Murray County) is not located within the geographic area covered by these rules.[7,8,9,10]

- NO_X from Electric Utility Steam Generating Units - GRAQC 391-3-1-.02(2)(jjj)
- NO_X from Fuel-Burning Equipment - GRAQC 391-3-1-.02(2)(lll)
- NO_X Emissions from Stationary Gas Turbines and Stationary Engines used to Generate Electricity - GRAQC 391-3-1-.02(2)(mmm)
- NO_X Emissions from Large Stationary Gas Turbines - GRAQC 391-3-1-.02(2)(nnn)
- NO_X from Small Fuel-Burning Equipment - GRAQC 391-3-1-.02(2)(rrr)

The following Georgia State rules are not applicable since OPC T.A. Smith is not one of the units listed in the regulations.

- Multipollutant Control for Electric Utility Steam Generating Units - GRAQC 391-3-1-.02(2)(sss)

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[6] GRAQC 391-3-1-.02(2)(tt)3

[7] GRAQC 391-3-1-.02(2)(jjj)8

[8] GRAQC 391-3-1-.02(2)(lll)4

[9] GRAQC 391-3-1-.02(2)(nnn)6

[10] GRAQC 391-3-1-.02(2)(rrr)2

- SO_2 Emissions from Electric Utility Steam Generating Units - GRAQC 391-3-1-.02(2)(uuu)

GRAQC 391-3-1-.02(12), (13), and (14) – Cross State Air Pollution Rules (Annual NO_X, Annual SO_2, and Ozone Season NO_X)

These regulations incorporate the Cross State Air Pollution Rule (CSAPR) requirements into the Georgia Rules for Air Quality Control. The regulations provide allocations for Georgia for 2017 and thereafter.

Federal Rule - PSD

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

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

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

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

Definition of BACT

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

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

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

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

New Source Performance Standards

The federal NSPS regulations are codified at 40 CFR Part 60. NSPS apply to new or modified "affected facilities" as defined in specific subparts of 40 CFR Part 60. Georgia EPD has been delegated the authority to administer the federal NSPS and has adopted by reference, unless otherwise noted, the NSPS standards. *See* Air Quality Control Rule 391-3-1- 02(8). Additional discussion of NSPS applicability is presented below.

40 CFR 60, Subpart A – General Provisions

Subpart A contains the general provisions of the NSPS regulations. Specifically, the provisions of Subpart A apply to the owner or operator of any stationary source that contains an affected facility, construction or modification of which is commenced after the date of publication of the standard and is subject to any standard, limitation, prohibition, or other federally enforceable requirement established pursuant to Part 60. General requirements may include notifications, monitoring, recordkeeping and/or performance testing of specific sources.

40 CFR 60 Subpart D – Fossil Fuel-Fired Steam Generators > 250 MMBtu/hr

NSPS Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators*, applies to fossil fuel-fired steam generating units with heat input capacities greater than 250 MMBtu/hr that have been constructed or modified since August 17, 1971. The rule defines a fossil fuel-fired steam generating unit as:[11]

"A furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer."

[11] 40 CFR 60.41

The combustion turbines and duct burners will not be subject to NSPS Subpart D, because:

- The turbines do not burn fossil fuel for the purpose of producing steam; and
- Units that are subject to NSPS Subpart KKKK are not subject to NSPS Subpart D.

Following the proposed modifications, OPC T.A. Smith's combustion turbines and HRSG with duct burners will be NSPS Subpart KKKK affected facilities.[12]

<u>40 CFR 60 Subpart Da – Electric Utility Steam Generating Units</u>

NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units*, provides standards of performance for electric utility steam generating units with heat input capacities greater than 250 MMBtu/hr of fossil fuel (alone or in combination with any other fuel) for which construction, modification or reconstruction commenced after September 18, 1978.[13]

Presently, per 40 CFR 60.40Da(e)(2), NSPS Subpart Da applies only to the HRSGs' duct burners, while the combustion turbines are subject to NSPS Subpart GG. NSPS Subpart Da does not include an applicability exemption for duct burners that are part of combined cycle turbine systems subject to NSPS Subpart GG.

However, the AGP Project III will result in a modification (as defined in NSPS Subpart A) of the CCCTs. As such, upon completion of the proposed modifications, each CCCT system (i.e., combustion turbines and HRSGs with duct burners) will become subject to requirements per NSPS Subpart KKKK. As a result, NSPS Subpart Da will no longer apply to the HRSGs with duct burners per exemptions specified in both NSPS Subpart Da [40 CFR 60.40Da(e)(1)] and NSPS Subpart KKKK [40 CFR 60.4305(b)]. Therefore, following the AGP Project III, no units at OPC T.A. Smith will be subject to NSPS Subpart Da.

<u>40 CFR 60 Subpart Db – Steam Generating Units > 100 MMBtu/hr</u>

NSPS Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.[14]

The term "steam generating unit" is defined under this regulation as:[15]

> *"Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart."*

[12] 40 CFR 60.40(e)

[13] 40 CFR 60.40Da(a)

[14] 40 CFR 60.40b(a)

[15] 40 CFR 60.41b

The combustion turbines each have a heat input capacity greater than 100 MMBtu/hr. However, as previously stated, the units are not steam generating units. Therefore, the combustion turbines are not subject to NSPS Subpart Db.

The HRSGs also each have a heat input capacity greater than 100 MMBtu/hr. The HRSGs are not currently subject to NSPS Subpart Db, as steam generating units meeting the applicability requirements under NSPS Subpart Da are exempt from Subpart Db.[16]

Following the completion of the proposed AGP Project III, the duct burners will no longer be subject to NSPS Subpart Da, as discussed in the previous section. However, pursuant to 40 CFR 60.40b(i), HRSGs that are associated with stationary combustion turbines that meet the applicability requirements of NSPS Subpart KKKK are not subject to NSPS Subpart Db.

Similarly, NSPS Subpart KKKK exempts any HRSGs and duct burners subject to NSPS Subpart KKKK from the requirements of NSPS Subparts Da, Db, and Dc.[17] As the combustion turbines will be subject to NSPS Subpart KKKK following the proposed modifications, NSPS Subpart Db will not apply to either the combustion turbines or the HRSGs at OPC T.A. Smith.

40 CFR 60 Subpart Dc – Small Steam Generating Units

NSPS Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for each steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989.[18] This subpart applies to steam generating units having a maximum rated heat input capacity of less than or equal to 100 MMBtu/hr and greater than or equal to 10 MMBtu/hr. NSPS Subpart Dc does not apply for similar reasons as detailed for NSPS Subpart Db: combustion turbines are not steam generating units, HRSGs subject to NSPS Subpart KKKK are exempt from NSPS Subpart Dc, and the size of the units exceeds the Subpart Dc applicability threshold.[19] However, the facility's existing natural gas-fired auxiliary boilers (31.4 MMBtu/hr each) are both subject to NSPS Dc. Neither of the proposed projects constitute a modification of the auxiliary boilers, and there are no changes to their applicable requirements under this rule as a result of the proposed project.

40 CFR 60 Subpart GG – Stationary Gas Turbines

NSPS Subpart GG, *Standards of Performance for Stationary Gas Turbines*, applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, that are constructed, modified, or reconstructed after October 3, 1977.[20]

Presently, the combustion turbines are subject to NSPS Subpart GG. However, upon completion of the proposed modifications, the combustion turbine systems will be subject to the more recently promulgated standards for Stationary Combustion Turbines under NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(b) (NSPS Subpart KKKK), stationary combustion turbines regulated

[16] 40 CFR 60.40b(e)

[17] 40 CFR 60.4305(b)

[18] 40 CFR 60.40c(a)

[19] 40 CFR 60.40c(e), 40 CFR 60.4305(b)

[20] 40 CFR 60.330(a), (b)

under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. Therefore, NSPS Subpart GG will no longer apply to the OPC T.A. Smith combustion turbines following the proposed project.

<u>40 CFR 60 Subpart KKKK – Stationary Combustion Turbines</u>

NSPS Subpart KKKK, *Standards of Performance for Stationary Combustion Turbines*, applies to all stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, and were constructed, reconstructed, or modified after February 18, 2005.[21]

OPC T.A. Smith has four natural gas-fired turbines, each with a heat input capacity exceeding 10 MMBtu/hr. To determine if the turbines will be subject to NSPS Subpart KKKK following either of the proposed projects, it is necessary to ascertain if a "modification" per the NSPS has occurred. For purposes of NSPS, a modification is defined as:[22]

> *"…any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted."*

More specifically, for an existing electric utility steam generating unit:[23]

> *"No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification…provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change."*

As AGP Project III results in an increased capacity of the turbine and duct burner systems, OPC has presumed that an increase in the amount of an air pollutant regulated by NSPS Subpart KKKK could occur on a short-term basis, since the heat input capacity of the system at 100% load is increasing. Therefore, once the proposed modification is complete, the OPC T.A. Smith combustion turbines will be subject to NSPS Subpart KKKK.

Pursuant to 40 CFR 60.4305(a), the associated HRSG and duct burners will be subject to NSPS Subpart KKKK.

Per 40 CFR 60.4305(b), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. HRSGs and duct burners regulated under NSPS Subpart KKKK are also exempt from the requirements of NSPS Subparts Da, Db, and Dc.

The following sections detail the applicable requirements as a result of NSPS Subpart KKKK applicability.

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[21] 40 CFR 60.4305(a), (b)

[22] 40 CFR 60.2

[23] 40 CFR 60.14(h)

Emission Limits

Per Table 1 to Subpart KKKK, a modified combustion turbine is limited to NOx emission limits depending on the type of fuel combusted and the heat input at peak load. For modified combustion turbines firing natural gas with a rating greater than 850 MMBtu/hr, the NOx emission standard is 15 ppm at 15% O2 or 0.43 lb/MWh useful output. Subpart KKKK also includes, for units greater than 30 MW output, a NOx limit of 96 ppm at 15% O_2 or 4.7 lb/MWh useful output for turbine operation at ambient temperatures less than 0 °F and turbine operation at loads less than 75% of peak load.[24] Compliance with the NOx emission limit is determined on a 30 unit operating day rolling average basis.[25] As the combustion turbines and duct burners are presently subject to a NOx limitation of 3 ppm at 15% O_2, 3-hour average per Condition 3.3.2 of the existing Title V operating permit, the new NSPS Subpart KKKK NOx limitations will be subsumed by the facility's NOx BACT limitation. SO_2 emissions from combustion turbines located in the continental U.S. are limited to 0.9 lb/MWh gross output (or 110 ng/J), or the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.[26]

Monitoring and Testing Requirements

Pursuant to 40 CFR 60.4333(a), the combustion turbines, air pollution control equipment, and monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction.

NO_X Compliance Demonstration Requirements

The combustion turbine systems presently employ a continuous emission monitoring system (CEMS) for NOx per the requirements of the Acid Rain Program (ARP), promulgated in 40 CFR Part 75. Pursuant to 40 CFR 60.4340(b)(2)(iv), with state approval, OPC T.A. Smith can rely on the methodologies per 40 CFR Part 75 Appendix E to demonstrate ongoing compliance with the NSPS Subpart KKKK NOx emission limits. Sources demonstrating compliance with the NOx emission limit via CEMS are not subject to the requirement to perform initial and annual NOx stack tests.[27] Initial compliance with the NOx emission limit will be demonstrated by comparing the arithmetic average of the NOx emissions measurements taken during the initial relative accuracy test audit (RATA) required pursuant to 40 CFR 60.4405 to the NOx emission limit under this subpart.[28]

SO_2 Compliance Demonstration Requirements

For compliance with the SO_2 emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as

[24] Table 1 to Subpart KKKK of Part 6

[25] 40 CFR 60.4350(h), 40 CFR 60.4380(b)(1)

[26] 40 CFR 60.4330(a)(1) or (a)(2), respectively

[27] 40 CFR 60.4340(b), 40 CFR 60.4405

[28] 40 CFR 60.4405(c)

approved by EPD;[29] however, OPC elects to opt out of this provision of the rule by using a fuel that is demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtuSO_2.[30] This demonstration can be made using one of the following methods:

1. By using a purchase contract specifying that the fuel sulfur content for the natural gas is less than or equal to 20 grains of sulfur per 100 standard cubic feet and results in potential emissions not exceeding 0.060 lb/MMBtu.

2. By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4, which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input.

OPC is currently required to monitor the sulfur content of the natural gas burned in the combustion turbines and duct burners through submittal of a semiannual analysis of the gas by the supplier or the facility to demonstrate that the sulfur content does not exceed its excursion threshold of 0.2 grains per 100 standard cubic feet.[31] This sulfur content analysis by the supplier or OPC satisfies the sulfur content demonstration methodologies in 40CFR 60.4365(a) and (b), respectively. Therefore, continued compliance with these existing permit conditions will guarantee compliance with these NSPS KKKK requirements.

Initial Notification

Per 40 CFR 60.7(a)(4), this permit application serves as the required notification for any physical or operational change to an existing facility which qualifies as an NSPS modification.

40 CFR 60 Subpart TTTT – Greenhouse Gas Emissions for Electric Generating Units

NSPS Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units* applies to any fossil fuel fired steam generating unit, Integrated Gasification Combined Cycle (IGCC) unit, or stationary combustion turbine constructed after January 8, 2014 or reconstructed after June 8, 2014 and to any steam generating unit or IGCC modified after June 8, 2014, provided that unit has a base load rating greater than 250 MMBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to the grid.[32] The existing CCCT generating units for OPC T.A. Smith each have peak heat inputs greater than 250 MMBtu/hr and serve a generator greater than 25 MW. Therefore, the CCCT generating units (including the duct burners) could potentially be subject to the provisions of NSPS TTTT. With respect to stationary combustion turbines, NSPS Subpart TTTT applies only to units that commenced construction or reconstruction after June 18, 2014, not modification. "Reconstruction" is defined as the replacement of components of an existing affected facility such that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable, entirely new affected facility that is technologically and economically capable of complying with the applicable standards. The total cost of the AGP Projects is $20.5 million for all four combustion turbines, and the cost of the Minimum Load Project is $20 million or less for all four turbines. In comparison, the cost of a comparable, entirely new "stationary combustion

[29] 40 CFR 60.4370(b) and (c)

[30] 40 CFR 60.4365

[31] Permit No. 4911-213-0034-V-08-0, Conditions 6.2.1, 6.2.2, and 6.1.7.c.i

[32] 40 CFR 60.5509(a)

turbine" under NSPS Subpart KKKK is approximately $390 million. Thus, the costs of these projects are far less than 50% of four comparable, entirely new "stationary combustion turbines" under Subpart KKKK. As the combustion turbines at OPC T.A. Smith are existing units, and the proposed projects do not meet the reconstruction definition, the modifications to the turbine systems will not trigger applicability of NSPS Subpart TTTT requirements.[33]

Non-Applicability of All Other NSPS

NSPS are developed for particular industrial source categories. The applicability of a particular NSPS to the proposed project can be readily ascertained based on the industrial source category covered. All other NSPS, besides Subpart A, are categorically not applicable to the proposed project.

National Emissions Standards For Hazardous Air Pollutants

NESHAP, located in 40 CFR 61 and 40 CFR 63, have been promulgated for source categories that emit HAPs to the atmosphere. A facility that is a major source of HAP is defined as having potential emissions of greater than 25 tpy of total HAPs and/or 10 tpy of individual HAP. Facilities with a potential to emit HAPs at an amount less than that which is defined as a major source are otherwise considered an area source. The NESHAP allowable emissions limits are most often established on the basis of a maximum achievable control technology (MACT) determination for the particular major source. The NESHAP apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type.

OPC T.A. Smith is presently classified as an area source of HAP emissions and will remain so following the proposed projects. The determination of applicability to NESHAP requirements for the proposed projects is detailed in the following sections. Rules that are specific to certain source categories unrelated to the proposed projects are not discussed in this regulatory review.

40 CFR 63 Subpart A – General Provisions

NESHAP Subpart A, *General Provisions*, contains national emission standards for HAPs defined in Section 112(b) of the Clean Air Act. All affected sources, which are subject to another NESHAP in 40 CFR 63, are subject to the general provisions of NESHAP Subpart A, unless specifically excluded by the source-specific NESHAP.

40 CFR 63 Subpart YYYY – Combustion Turbines

NESHAP Subpart YYYY, *NESHAP for Stationary Combustion Turbines*, establishes emission and operating limits for stationary combustion turbines located at major sources of HAP. Natural gas turbines at major sources are presently only subject to initial notifications requirements. As an area source of HAP, NESHAP Subpart YYYY does not apply to operations at OPC T.A. Smith.

[33] 40 CFR 60.5509(a)

40 CFR 63 Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters

NESHAP Subpart DDDDD, *NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* (Major Source Boiler MACT) regulates boilers and process heaters at major sources of HAPs.[34] As an area source of HAP, OPC T.A. Smith is not subject to the Major Source Boiler MACT. Furthermore, pursuant to 40 CFR 63.7575:

> *"Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.*
>
> *Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas."*

The rule defines a "boiler" as an enclosed device using controlled combustion to recover thermal energy in the form of steam and/or hot water. The combustion turbines use the thermal energy of natural gas directly through combustion, without use of a steam or hot water cycle; they would not fall within the definition of a "boiler".

As the definition of "boiler" also specifically excludes "waste heat boilers," the modified duct burners and HRSGs at OPC T.A. Smith also would not be subject to NESHAP Subpart DDDDD even if the site were to become a major source in the future.

40 CFR 63 Subpart UUUUU – Electric Utility Steam Generating Units

NESHAP Subpart UUUUU, *NESHAP for Electric Utility Steam Generating Units*, applies to electric utility steam generating units (EGUs) that combust coal or oil.[35] Furthermore, pursuant to 40 CFR 63.9983(a), area source stationary combustion turbines, other than IGCC units, are not subject to Subpart UUUUU. As the OPC T.A. Smith combustion turbines and duct burners combust natural gas only, and will continue to combust natural gas only, and are located at an area source, NESHAP Subpart UUUUU will not apply.

40 CFR 63 Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources

NESHAP Subpart JJJJJJ, *NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources* (Area Source Boiler MACT) regulates boilers at area sources of HAP.[36] The proposed turbines do not meet the boiler definition pursuant to 40 CFR 63.11237, which also excludes waste heat boilers:

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[34] 40 CFR 63.7480

[35] 40 CFR 63.9980

[36] 40 CFR 63.11193

> *"Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler."*

Furthermore, even if the turbines or duct burners did meet this definition, gas-fired boilers are exempt from NESHAP Subpart JJJJJJ.[37] Therefore, the requirements of NESHAP Subpart JJJJJJ do not apply to any equipment being modified as part of the proposed projects. Also, the facility auxiliary boilers only combust natural gas, rendering them exempt from NESHAP Subpart JJJJJJ.

Non-Applicability of All Other NESHAP

NESHAP are developed for particular industrial source categories. The applicability of a particular NESHAP to the proposed project can be readily ascertained based on the industrial source category covered. All other NESHAPs, besides Subpart A, are categorically not applicable to the proposed projects.

State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from Block 1 (being CCCT1 and CCCT2 and steam turbine), and Block 2 (being CCCT3 and CCCT4 and steam turbine) associated with the proposed project would most likely result from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

Compliance Assurance Monitoring (CAM)

Under 40 CFR 64, Compliance Assurance Monitoring (CAM) facilities are required to prepare and submit monitoring plans for certain emissions units with Title V operating permit applications. The CAM plans are intended to provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation only applies to emission units that use a control device to achieve compliance with an emission limit and whose pre-control emissions exceed the major source thresholds under the Title V operating program. For a subject unit whose post-control emissions also exceed the major source threshold, a CAM plan is required to be submitted with the initial or modification Title V operating permit application. For a subject unit whose post-control emissions are less than the major source threshold, a CAM plan does not have to be submitted until the next Title V renewal application.

Each combustion turbine/duct burner stack is equipped with an SCR to reduce NO_X emissions. In addition, these units have NO_X CEMS to verify proper operation. The combustion turbines are currently complying with the CAM plan included in Conditions 5.2.7 through 5.2.8 of Permit No. 4911-213-0034-V-08-0, which was derived through previously submitted CAM plans as part of prior historic permitting actions. At this time, no changes to the existing CAM requirements are requested. Therefore, no CAM documentation has been included within the facility's PSD permit application (Application No. TV-343530)

[37] 40 CFR 63.11195(e)

Federal Rule – 40 CFR 68 – Risk Management Plan

Subpart B of 40 CFR 68 outlines requirements for risk management prevention plans pursuant to Section 112(r) of the Clean Air Act. Applicability of the subpart is determined based on the type and quantity of chemicals stored at a facility. OPC T.A. Smith does not exceed the threshold quantity for any of the chemicals and is, therefore, not subject to 40 CFR 68 Subpart B. The proposed projects will not include changes to the facility's ammonia storage tanks or the concentration of ammonia stored and, therefore, will not impact the facility's requirements under 40 CFR 68. OPC T.A. Smith is and will continue to be subject to the General Duty Clause under the Clean Air Act Section 112(r)(1), which states:

> *"The owners and operators of stationary sources producing, processing, handling or storing such substances [i.e., a chemical in 40 CFR part 68 or any other extremely hazardous substance] have a general duty [in the same manner and to the same extent as the general duty clause in the Occupational Safety and Health Act (OSHA)] to identify hazards which may result from (such) releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur."*

Federal Rule – 40 CFR 82 – Stratospheric Ozone Protection Regulations

The requirements originating from Title VI of the Clean Air Act, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A through E and Subparts G and H of 40 CFR 82 are not applicable to OPC T.A. Smith. 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility operates, maintains, repairs, services, or disposes of appliances that utilize Class I, Class II, or non-exempt substitute refrigerants.[38] Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. It is expected that all repairs, service, and disposal of ozone depleting substances from such equipment (air conditioners, refrigerators, etc.) at the facility will be completed by a certified technician. OPC T.A. Smith will continue to comply with 40 CFR 82 Subpart F.

Federal Rule – 40 CFR 72, 73, 74 – Acid Rain Program

In order to reduce acid rain in the United States and Canada, Title IV (40 CFR 72 *et seq.*) of the Clean Air Act Amendments of 1990 established the ARP to substantially reduce SO_2 and NO_X emissions from electric utility plants. Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I and Phase II of the program. Upon Phase III implementation, the ARP in general applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale. The turbines at OPC T.A. Smith are utility units subject to the ARP. The facility is subject to the requirements of 40 CFR 72 (permits), 40 CFR 73 (SO_2), and 40 CFR 75 (monitoring) but is not subject to the NO_X provisions (40 CFR 76) of the ARP regulations because the turbines do not have the capability to burn coal.

Under 40 CFR 75 of the ARP, OPC T.A. Smith is required to operate a NO_X CEMS for each unit to monitor the NO_X emission rate (lb/MMBtu), and to determine SO_2 and CO_2 mass emissions (tons) following the procedures in Appendices D and G, respectively. Further, the ARP requires the facility to possess SO_2 allowances for each ton of SO_2 emitted. The ARP also requires initial certification of the monitors within 90 days of commencement of commercial operation, quarterly

[38] 40 CFR 82.150

reports, and an annual compliance certification. The ARP requirements are outlined in Section 7.9 and Attachment D of the Title V permit amendment No. 4911-213-0034-V-08-2. The proposed projects will not alter any applicable requirements or compliance options of ARP to the OPC T.A. Smith operations. The facility will continue to maintain sufficient allowances under ARP for its operations.

Federal Rule – 40 CFR 96 / 97 – Clean Air Interstate Rule (CAIR)/ Cross-State Air Pollution Rule (CSAPR)

The CAIR, 40 CFR 96, called for reductions in SO_2 and NO_X by utilizing an emissions trading program. More broadly, 40 CFR 96 also includes a forerunner to CAIR, the NO_X SIP Call / NO_X Budget program, and the name of 40 CFR 96 (NO_X Budget Trading Program for State Implementation Plans) still reflects the origins in regulating only NO_X.

The CSAPR was developed to require affected states to reduce emissions from power plants that contribute to ozone and/or particulate matter emissions.[39] Initially finalized on July 6, 2011, the CSAPR was scheduled to replace the CAIR on January 1, 2012. However, on December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit") stayed CSAPR, pending a subsequent decision. On August 21, 2012, the D.C. Circuit then vacated CSAPR, remanding it back to EPA for further rulemaking, leaving CAIR in effect until a replacement rule was promulgated.[40] Upon appeal, the U.S. Supreme Court – on April 29, 2014 – upheld the CSAPR, reversing the D.C. Circuit's decision and remanding the case back to that Court for further proceedings consistent with its April 2014 decision. Upon remand, the U.S. government filed a motion with the D.C. Circuit for a lift of the stay of CSAPR on June 26, 2014, and this motion was granted on October 23, 2014. Therefore, the CSAPR has replaced the CAIR. CSAPR Phase 1 implementation began January 1, 2015 for annual programs and May 1, 2015 for the ozone season program. Phase 2 implementation began on January 1, 2017 for annual programs, and May 1, 2017 for ozone season programs.

Therefore, since CSAPR is currently effective, potential applicability is evaluated against the CSAPR Program and not CAIR. CSAPR applicability is found in 40 CFR 97.404 and definitions in 40 CFR 97.402 and implemented via Georgia EPD through GRAQC 391-3-1-.02(12) – (13). The CSAPR rule aims to improve air quality by reducing emissions from power plants that contribute to ozone and/or fine particulate pollution in other states. Georgia is subject to CSAPR programs for both fine particles (SO_2 and annual NO_X) and ozone (ozone season NO_X).[41]

CSAPR applicability is similar but distinct from ARP, with applicability criteria and definitions per 40 CFR 97.402.[42] In general, CSAPR regulates fossil-fuel-fired boilers and combustion turbines serving, on any day starting November 15, 1990 or later, an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale. OPC T.A. Smith's CCCTs are affected sources under this regulation, and the proposed projects will not alter any applicable requirements or compliance options of CSAPR to the

[39] http://www.epa.gov/airtransport/

[40] EME Homer City Generation, L.P. v. U.S. EPA. U.S. Court of Appeals for the District of Columbia Circuit, No. 11-1302, decided August 21, 2012.

[41] https://www.epa.gov/airmarkets/map-states-covered-csapr

[42] CSAPR applicability and definitions are repeated in four separate subparts of 40 CFR 97, but each has identical definitions and applicability requirements. Subpart AAAAA (5A), which is for the NO_X Annual program, is used in this discussion.

facility's operations. OPC T.A. Smith will continue to maintain sufficient allowances under CSAPR for its operations.

4.0 CONTROL TECHNOLOGY REVIEW

The BACT requirement applies to each new or modified emission unit from which there is an emissions increase of pollutants subject to PSD review. The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e).

Accordingly, a BACT analysis and detailed discussion of each pollutant subject to PSD permitting is assessed herein for the combustion turbine systems, including the combustion turbine and HRSG with duct burner. No other units are being physically modified or constructed as part of the proposed projects.

Combustion Turbine and HRSG Duct Burner System - Background

Under AGP Project III, OPC T.A. Smith is considering control changes that would allow OPC to utilize the maximum capability of the AGP components, via the duct burners. If implemented, this change would increase the capacity of each block by approximately 28.6 MW in the summer, and 31.0 MW in the winter (Block 1 being CCCT1 and CCCT2 and steam turbine, and Block 2 being CCCT3 and CCCT4 and steam turbine). These control changes would result in an associated increase in maximum heat inputs and maximum hourly rate of emissions when the duct burners are used at their full capability. Implementation of AGP Project III would not increase the noise emissions from OPC T.A. Smith above historical levels and does not require any changes in the facility's gas supply infrastructure.

Applicant's Proposal

Combustion Turbine and HRSG Duct Burner System – Filterable PM/Total PM_{10}/Total $PM_{2.5}$ Emissions

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT on particulate related emissions from each combustion turbine system, including the turbine and duct burner associated with the HRSG. The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits selected as BACT for filterable PM and total PM_{10}/$PM_{2.5}$.

While BACT emission limits for PM_{10} and $PM_{2.5}$ must include the condensable portion of particulate, most demonstrated control techniques are limited to those that reduce filterable particulate matter. As such, control techniques for filterable PM, or PM_{10} also reduce filterable $PM_{2.5}$. The PM BACT analyses for filterable PM and filterable PM_{10} will also satisfy BACT for the filterable portion of $PM_{2.5}$. In the prepared BACT analyses, references to PM_{10} are also relevant for $PM_{2.5}$. A potential source of secondary particulate matter from the proposed projects is due to NO_X emissions from each combustion turbine system. As OPC T.A. Smith operates SCR control on each turbine system, secondary PM BACT is effectively addressed by controlling the direct emissions of NO_X. These projects also do not trigger PSD review for the $PM_{2.5}$ precursor SO_2, as project emissions increases are less than the applicable SO_2 SER (significance emission rate). As such, secondary PM BACT is not required to be addressed separately.

PM Formation – Turbine Systems

Filterable PM, PM_{10} and $PM_{2.5}$ emissions from natural gas combustion result primarily from incomplete combustion and by ash and sulfur in the fuel.[43] Combustion of natural gas generates low PM emissions in comparison to other fuels due to the low ash and sulfur contents.

In contrast to filterable particulate, condensable particulate is the portion of PM emissions that exhausts from the stack in gaseous form but condenses to form particulate matter once mixed with the cooler ambient air.

Condensable particulate results from sulfur in the fuel and the resultant H_2SO_4, NO_X being oxidized to nitric acid (HNO_3), and high molecular weight organics. A combustion turbine operating without an SCR will have lower condensable PM emissions than a similar unit operating with an SCR. The increased condensables result from formation of ammonium sulfates from unreacted ammonia in the control system. Accordingly, emission estimates for total $PM_{10}/PM_{2.5}$ when utilizing an SCR for NO_X emissions reductions are higher than the total $PM_{10}/PM_{2.5}$ emissions anticipated from turbine systems that do not utilize NO_X controls.

Identification of PM Control Technologies - Turbine Systems

Trinity Consultants reviewed recently issued air permits and permit files and performed searches of the RBLC database in October 2018 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for emission sources comparable to the proposed project. For combustion turbines, the following categories were searched:[44]

- Permit Data between 10/25/2008 and 10/25/2018
- Process Type: 15.110 Large Natural Gas Simple Cycle Combustion Turbines and 15.210 Large Natural Gas Combined Cycle Combustion Turbines[45]
- Process Pollutants All
- Results are for USA, Mexico, and Canada

The following $PM_{10}/PM_{2.5}$ control technologies were identified based on the RBLC search, a limited review of information published in technical journals, and experience in conducting control technology reviews for similar types of equipment. Taking into account the physical and operational characteristics of the units, the candidate control options for particulate matter reduction include:

[43] AP-42, Chapter 1, Section 4, Natural Gas Combustion, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*. April 2000

[44] The proposed combustion turbine system modifications are for combined cycle combustion turbines with HRSGs with duct burners. RBLC searches were performed for simple cycle combustion turbines as well as combined cycle for completeness.

[45] Upon review of records from the RBLC database, certain corrections were made to the entries as appropriate. For instance, many entries designated as 15.110 Simple Cycle Combustion Turbines were actually Combined Cycle Combustion Turbines or vice versa. In cases where a clear determination could be made based on the project description or other details provided, the RBLC designation code was corrected in the summary tables. Note also that units combusting fuels in addition to natural gas (such as biomass or ethanol blends) have been removed from the summary list.

- Multiclone
- Wet Scrubber
- Electrostatic Precipitator
- Baghouse
- Low sulfur fuel
- Good combustion and operating practices

Multicyclone

Multicyclones consist of several small cyclones operating in parallel. The cyclone creates a double vortex inside its shell, conveying centrifugal force on the inlet exhaust stream. The exhaust stream is then forced to move circularly through the cyclone, and the particulate matter in the stream is pushed to the cyclone walls. While this is effective for larger particles, smaller particles tend to be overtaken by the fluid drag force of the air stream and will depart the cyclones with the exiting air stream. The particulate removal in cyclones can be improved by having more complex gas flow patterns.[46] The control efficiency range for high efficiency single cyclones is 30- 90% for PM_{10} and 20 - 70% for $PM_{2.5}$. The use of multicyclones leads to greater PM control efficiency than from a single cyclone, resulting in control efficiencies in the range of 80-95% for particles greater than 5 microns in diameter (PM_5).[47] Multicyclones in parallel can typically handle a higher flowrate when compared to a single cyclone unit, up to approximately 106,000 standard cubic feet per minute (scfm). The allowable inlet gas temperature for a cyclone is limited by the type of construction material, but can be as high as 540°C (1,000°F).[48] Cyclones are generally used as precleaners for final control devices such as fabric filters/baghouses or ESPs due to the lower control efficiency of smaller particles from a cyclone.[49]

Wet Scrubbers

Wet (in particular, venturi) scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water. The PM collection efficiencies of Venturi scrubbers range from 70% to greater than 99%, depending on the application. Collection efficiencies are generally higher for PM with aerodynamic diameters of approximately 0.5 µm ($PM_{0.5}$) to 5 µm (PM_5). Inlet gas temperatures for wet scrubbers usually range from 4 to 400°C (40 to 750°F), with typical gas flowrates for single-throat scrubbers ranging from 500 to 100,000 scfm.[50]

ESP

An ESP removes particles from an air stream by electrically charging the particles then passing them through a force field that causes them to migrate to an oppositely charged collector plate. After the particles are collected, the plates are knocked ("rapped"), and the accumulated particles fall into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends

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[46] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

[47] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

[48] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

[49] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

[50] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Venturi Scrubbers, EPA-452/F-03- 017.

on particle diameter, electrical field strength, gas flow rate, gas temperature, and plate dimensions. An ESP can be designed for either dry or wet applications.[51] An ESP can generally achieve approximately 99 - 99.9% reduction efficiency for PM emissions. Typical ESPs can handle approximately 1,000 to 100,000 scfm, at high temperatures up to 700°C (1,300°F).[52]

Baghouse (Fabric Filter)

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Particulate laden gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags suffered in the cleaning process.[53] Typically, gas temperatures up to 260°C (500°F) can be accommodated routinely in a baghouse. The fabric filters have relatively high maintenance requirements (for example, periodic bag replacement), and elevated temperatures above the designed temperature can shorten the fabric life. Additionally, a baghouse/fabric filter cannot be operated in moist environments where the condensation of moisture could cause the filter to be plugged, reducing efficiency. Under the proper operating conditions, a baghouse can generally achieve approximately 99 - 99.9% reduction efficiency for PM emissions.[54]

Depending on the need, baghouses are available as standard units from the factory, or custom baghouses designed for specific applications. Standard baghouses can typically handle 100 to 100,000 scfm; while custom baghouses are generally larger, ranging from 100,000 to over 1,000,000 scfm.[55]

Low Sulfur Fuels

Exclusively combusting pipeline-quality natural gas with an inherently low sulfur content will reduce particulate emissions compared to other available fuels as there is less potential to form H_2SO_4.

Good Combustion and Operating Practices

Good combustion and operating practices imply that the unit is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible.

A properly operated combustion unit will minimize the formation of particulate emissions due to incomplete combustion. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios and periodic tuning.

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[51] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996.

[52] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) – Wire-Pipe Type, EPA-452/F-03-027.

[53] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996.

[54] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Fabric Filter – Pulse-Jet Cleaned Type, EPA-452/F-03-025.

[55] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Fabric Filter – Pulse-Jet Cleaned Type, EPA-452/F-03-025.

Elimination of Technically Infeasible PM Control Options – Turbine Systems

All four of the add-on control technologies (multicyclones, wet scrubbers, ESPs, and baghouses) are technically infeasible for filterable particulate from natural gas combustion. Although the add-on control technologies identified are utilized in several processes to control particulate emissions, none of these add-on control technologies are applicable to natural gas-fired combustion turbines. Combustion of natural gas generates relatively low levels of particulate emissions in comparison to other fuels due to its low ash and sulfur contents. In addition, turbines operate with a significant amount of excess air, which generates large exhaust flow rates. The low level of particulate emissions combined with the large exhaust gas volume results in very low concentrations of particulate.

Due to the low particulate concentration in the exhaust gas, add-on filterable particulate controls would not provide any significant degree of emission reduction for the combustion turbine systems and are therefore not considered further in this analysis.[56]

The remaining feasible control technologies include low sulfur fuels and good combustion and operating practices. Good combustion and operating practices in conjunction with low sulfur natural gas combustion represents the base case for the combustion turbine system, including the turbine and duct burner associated with the HRSG. Therefore, as this is the highest-ranking feasible control remaining, it is selected as BACT.

Selection of Emission Limits and Controls for PM BACT – Turbine Systems

The combustion turbine systems including the turbine and duct burner associated with the HRSG will not be subject to any NSPS or NESHAP standard for $PM/PM_{10}/PM_{2.5}$ and thus there is no floor of allowable $PM/PM_{10}/PM_{2.5}$ BACT limits. Each individual CCCT system (i.e., combined combustion turbine and duct burner system) is currently subject to a 25 lb/hr filterable PM limit per Condition 3.3.2.c of Permit No. 4911-213-0034-V-08-0, which was the negotiated BACT limit applicable when the systems were originally constructed.[57]

As the selected BACT for particulate matter emissions relies on good combustion and operating practices in conjunction with the use of low sulfur natural gas, OPC T.A. Smith searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas CCCT systems are provided in the RBLC summary table in the facility's PSD application (See Appendix C in Application No. TV-343540). Review of the RBLC entries confirms that add-on control for particulate emissions is not required for natural gas-fired CCCT systems. Typical listings denote "good combustion practices" or similar variants. Some entries may also denote the use of pipeline quality natural gas or inlet air filtration. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines. While some RBLC entries denote the use of pipeline quality natural gas or inlet air filtration, these are

[56] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of particulates, page 43

[57] At the time the units were originally permitted, regulatory requirements did not mandate inclusion of condensable PM as part of BACT emission limitations. The established filterable PM limit served as the BACT requirement for TSP and filterable PM_{10}. Permit No. 4911-213-0034-P-01-1, Permit Condition 2.11, effective October 22, 2002. Current Permit Condition No. 3.3.2.c.

typically aspects of the basic design of CCCT systems and do not necessarily require explicit consideration.[58]

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries provides an indication of what has been considered appropriate BACT emission limitations for potentially similar units as those being modified by OPC T.A. Smith. The majority of the RBLC database entries relate to the installation of new state-of-the-art CCCT systems, not modifications of existing CCCT units. Given the advancements in turbine design and good combustion practices, it is not anticipated that modification of an older generation turbine system would improve combustion efficiency and performance in a manner that would be comparable to installation of a new, state-of-the-art turbine system. Therefore, for comparison purposes, the RBLC entries of interest for OPC T.A. Smith are other potentially modified natural gas combustion turbine systems, summarized in Table 5-3 of the facility's PSD application (Application No. TV-343540), based on the modification designated in the RBLC entry.

The following sections detail the various permitting actions identified as modifications in Table 5-3 and highlights the commonalities or differences to the OPC T.A. Smith generating units.

Hanging Rock

Duke Energy received a Permit to Install (e.g., a construction permit) for the original Hanging Rock, LLC (Hanging Rock) site in 2001, described as a 1,270 MW Combined Cycle Power Plant consisting of four combined cycle 172 MW natural gas fired GE 7FA turbines with four HRSGs.[59] As OPC T.A. Smith was originally owned by Duke Energy when first permitted, it is reasonable to conclude that the original GE 7FA engines installed at Hanging Rock were similar to those installed/permitted for OPC T.A. Smith. In July 2015, the Hanging Rock facility underwent a permit modification to upgrade the four CCCTs at the site to allow for increased electrical output. The issued permit described the upgraded assets as GE 7FA natural gas fired turbines each with a nominal capacity of 2,045 MMBtu/hr and duct burner nominally rated at 587 MMBtu/hr.[60] The 2015 permitting event was not a PSD major modification; however, the BACT limits established in 2001 for filterable PM/PM_{10} were reduced as part of the 2015 permit modification, presumably to ensure PSD permitting was not required at that time.[61]

Given the facility descriptions, use of GE 7FA engines, and timing of the original construction permitting and subsequent modification, it is reasonable to presume that the Hanging Rock CCCTs are comparable to the units at OPC T.A. Smith. Table 4-1 summarizes the particulate matter emission limits per the original permit and the 2015 modification permit.

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[58] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of particulates, pages 42 – 49.

[59] Final Permit to Install 07-00503 issued by the Ohio EPA to Duke Energy – Hanging Rock, LLC, December 13, 2001.

[60] Final Permit to Install P0117322 issued by the Ohio EPA to Hanging Rock Energy Center, July 15, 2015.

[61] Draft Permit to Install P0117322 issued by the Ohio EPA to Hanging Rock Energy Center, June 5, 2015, discussion in permit strategy write-up and permit condition in Section C 1.b)(2)c. Other pollutant BACT limits were also reduced, including NO_X, SO_2, CO, H_2SO_4, and VOC.

Table 4-1: Hanging Rock CCCT Particulate Matter Limit Summary

Permit Year	Unit	Limit	Unit	Pollutant	Basis
2001	CT Only	15	lb/hr	Filterable PM/PM_{10}	Method 5
2015	CT Only	10.2	lb/hr	PM/PM_{10}/$PM_{2.5}$ (Total)	Method 5, 201, 202
2001	CT with DB	23.3	lb/hr	Filterable PM/PM_{10}	Method 5
2015	CT with DB	14.6	lb/hr	PM/PM_{10}/$PM_{2.5}$ (Total)	Method 5, 201, 202

Similar to OPC T.A. Smith, the original 2001 permit presents particulate matter limits in terms of filterable PM/PM_{10} only, relying on a Method 5 test for compliance purposes. The modified permit in 2015 updates the particulate-based limits to reflect the need for total PM_{10} and total $PM_{2.5}$ limitations, as the test method basis includes Method 5, 201 and 202.

Given the equipment similarities, it is reasonable to anticipate that the OPC T.A. Smith units could have a similar emissions profile following the proposed projects as the Hanging Rock units have following their modifications. The existing OPC T.A. Smith permit includes a 25 lb/hr filterable PM limitation on each combustion turbine with duct burner firing resulting from its original permitting action. The equivalent Hanging Rock limit from its 2001 permit is 23.3 lb/hr, supporting this presumption.

As lb/hr emission limits are dependent on the nominal capacity of the CCCTs and the Hanging Rock unit capacities differ somewhat from the OPC T.A. Smith units, OPC converted the Hanging Rock lb/hr limits to approximate equivalent lb/MMBtu values, per the nominal capacities defined in Hanging Rock's 2015 permit, for comparison purposes. These values are summarized in Table 4-2.

Table 4-2: Hanging Rock CCCT Particulate Matter Lb/MMBtu Estimates

Permit Year	Unit	Limit	Unit	Pollutant	Basis
2015	CT Only	0.0050	lb/MMBtu	PM/PM_{10}/$PM_{2.5}$ (Total)	Method 5, 201, 202
2015	CT with DB	0.0055	lb/MMBtu	PM/PM_{10}/$PM_{2.5}$ (Total)	Method 5, 201, 202

If one relies on the Hanging Rock permit limits as a reasonable basis for PM BACT for the OPC T.A. Smith units in terms of the estimated lb/MMBtu, the proposed BACT limit would potentially be equivalent to **0.0055 lb/MMBtu** for operation of the combustion turbine with duct burner. The equivalent OPC T.A. Smith lb/hr rate, based on nominal heat input capacities of 1,859 MMBtu/hr for the combustion turbine and 578 MMBtu/hr for the duct burner is **13.4 lb/hr** for total PM_{10} and total $PM_{2.5}$. If the lb/MMBtu value were rounded to **0.006 lb/MMBtu**, the resulting lb/hr rate would be **14.62 lb/hr**, indicating the importance of significant digits in the derivation of the mass emission rate value.

CPV St. Charles

CPV St. Charles (CPV) commenced commercial operation of a natural gas CCCT energy facility with a nominal capacity of 725 MW in 2017.[62] The energy center consists of two GE 7FA natural gas CCCTs. In the original permitting efforts for the facility, CPV anticipated installation of GE 7FA.04 turbines, but subsequently modified their application for installation of GE 7FA.05 turbines, allowing for more efficient and increased MW production.[63] In 2018, CPV St. Charles received a modified order related to replacement of the dry low NO_X GE 2.6 combustors with GE dry low NO_X 2.6+ combustors, alteration of the hours limitations on the duct burners, and other condition updates.[64] While the RBLC database infers the 2014 action as a "modification", it was not a traditional modification of existing equipment or operation, merely a revision of the proposed equipment for installation. Therefore, the CPV equipment represents new turbines, albeit GE 7FA turbines of a more modern design than those installed and operating at OPC T.A. Smith. Considering the turbine type, a review of the BACT limits established for CPV based on the 2014 action is warranted, despite being a new installation. Table 4-3 summarizes the particulate matter emission limits for the CPV St. Charles GE 7FA.05 turbines.

Table 4-3: CPV St. Charles CCCT Particulate Matter Lb/MMBtu Estimates

Permit Year	Unit	Limit	Unit	Pollutant	Basis
2014	CT with or without DB	0.007	lb/MMBtu	Filterable PM	Method 5
2014	CT with or without DB	0.011	lb/MMBtu	$PM_{10}/PM_{2.5}$ (Total)	Method 201A and 202
2018	CT Only	0.005	lb/MMBtu	Filterable PM	Method 5
2018	CT Only	0.008	lb/MMBtu	$PM_{10}/PM_{2.5}$ (Total)	Method 201A and 202
2018	CT with DB	0.004	lb/MMBtu	Filterable PM	Method 5
2018	CT with DB	0.006	lb/MMBtu	$PM_{10}/PM_{2.5}$ (Total)	Method 201A and 202

An interesting contrast between the Hanging Rock emission limits and the CPV St. Charles emissions limits is the difference between the limits when the duct burner is included. For Hanging Rock, the estimated lb/MMBtu increases when the duct burner is firing, whereas for CPV St. Charles, the lb/MMBtu permit limits decrease when the duct burner is included. There are multiple factors which may be influencing the established limit such as the typical operating scenario anticipated for duct burner firing (time of year, resulting atmospheric conditions) and the size of the duct burners themselves (the Hanging Rock units are larger than the CPV St. Charles units). In all, the resulting limit for total $PM_{10}/PM_{2.5}$ for the combustion turbine with duct burner firing scenario based on the 2018 modification permit is reasonably equivalent between the two sites, **0.006 lb/MMBtu**, which would result in a **14.62 lb/hr** mass emission rate for each of the OPC T.A. Smith units (combustion turbine with duct burner). Note, however, that the hourly mass emission rate increases to **14.87 lb/hr** for each of the OPC T.A. Smith combustion turbines (no duct burner firing) when relying on the **0.008 lb/MMBtu** turbine-only limit from the 2018 modification.

[62] http://www.cpv.com/our-projects/cpv-st-charles/

[63] Environmental Review of the Proposed Modification to the CPV St. Charles Project (Draft), Maryland Department of Natural Resources, PSC Case No. 9280, July 9, 2012.

[64] Proposed Order of Public Utility Law Judge, Case No. 9437, State of Maryland Public Service Commission, dated March 5, 2018. Order was finalized without change on March 16, 2018 and assigned Order No. 88609. Files available at https://www.psc.state.md.us/search-results/?keyword=9437&x.x=9&x.y=18&search=all&search=case

However, the limit that has been demonstrated as a result of the CPV units commencing operation in 2017, and is most comparable to the OPC T.A. Smith units would be based on the 2014 permit, **0.011 lb/MMBtu**, resulting in a **26.81 lb/hr** total $PM_{10}/PM_{2.5}$ mass emission rate for the OPC T.A. Smith units (combustion turbine with duct burner).

New Covert Generating Facility

The New Covert Generating Facility received a modification permit in July 2018. The Permit to Install indicates that the existing natural gas CCCT systems at the facility were originally installed in 2001, similar to the timing of OPC T.A. Smith units. However, while the timing is similar, the installed turbines at New Covert Generating are Mitsubishi model 501G units, with emission profiles of a different nature than the GE 7FA turbine. Following the completion of the planned modification, the permit defined heat input capacity of each combustion turbine will be 2,829 MMBtu/hr, with a duct burner heat input basis of 256 MMBtu/hr (HHV).[65] The permit establishes a total $PM_{10}/PM_{2.5}$ emission limit of 10.7 lb/hr, estimated to be equivalent to **0.00346 lb/MMBtu** based on the listed HHV heat input capacities for the CT with duct burner firing. Given the unique emission profiles associated with the manufacturer design of different natural gas CCCT units, OPC T.A. Smith maintains that the New Covert generating facility BACT limit for a Mitsubishi model turbine is not an appropriate limitation for a GE 7FA turbine.

Midland Cogeneration Venture (Midland)

Midland Cogeneration Venture (Midland) received a permit for installation of new natural gas CCCTs at an existing facility in 2013. Per input from the Michigan Department of Environmental Quality, the permit allowed for the installation of either GE 7FA.05 or Siemens SGT6-5000F turbines. The proposed project has not been completed to-date. A summary of the particulate matter BACT limits established for Midland is presented in Table 4-4 given the proposed project included the possible installation of a GE 7FA.05 turbine.[66]

Table 4-4: Midland Cogeneration Venture (Midland) CCCT Particulate Matter Lb/MMBtu Estimates

Unit	Limit	Unit	Pollutant	Basis
CT Only	0.0060	lb/MMBtu	Filterable PM	Method 5
CT Only	0.0120	lb/MMBtu	$PM_{10}/PM_{2.5}$ (Total)	Method 201A and 202
CT with DB	0.0040	lb/MMBtu	Filterable PM	Method 5
CT with DB	0.0080	lb/MMBtu	$PM_{10}/PM_{2.5}$ (Total)	Method 201A and 202

While the Midland permit is for a new turbine system, the BACT emission limits for combustion turbines with duct burner firing are higher than the emission limits reviewed for Hanging Rock and CPV St. Charles (2018 modification). The Midland limits are comparable to the 2014 CPV St. Charles limit of 0.011 lb/MMBtu for the turbines with or without duct burner firing, likely given the possibility of installation of a GE 7FA.05 turbine. The turbine with duct burner limit of **0.0080 lb/MMBtu** total $PM_{10}/PM_{2.5}$ results in a **19.50 lb/hr** mass rate for each of the OPC T.A.

[65] Permit to Install 186-17 issued by the Michigan Department of Environmental Quality, July 30, 2018.

[66] Renewable operating permit No. MI-ROP-B6527-2014a, revised June 16, 2016, for Midland Cogeneration Venture Limited Partnership. Permit issued by the Michigan Department of Environmental Quality.

Smith units; the turbine-only limit of **0.012 lb/MMBtu** total $PM_{10}/PM_{2.5}$ results in a **22.31 lb/hr** mass emission rate for each of the OPC T.A. Smith units.

Renaissance Power, Ltd.

This proposed modification involved the retrofit of existing simple cycle combustion turbines to combined cycle units. The existing turbines are Westinghouse units. The project did not occur and the Michigan Department of Environmental Quality has voided the permit to install. In light of all these factors, the Renaissance Power entries are not considered further in these BACT analyses.

Summary

The anticipated BACT for filterable PM, total $PM_{10}/PM_{2.5}$ would be good combustion practices and the use of low sulfur natural gas. Table 4-5 summarizes the BACT limits for total $PM_{10}/PM_{2.5}$ for potentially comparable units in terms of lb/MMBtu, with the resulting lb/hr mass emission rate that would apply to the OPC T.A. Smith units, broken down by turbine alone or turbine with duct burner firing. For the turbine alone, the estimated mass emission rates range between 9.27 lb/hr to 26.81 lb/hr; for the turbine with duct burner firing, the range is between 13.52 lb/hr to 26.81 lb/hr.

Table 4-5: Summary of Reviewed Total PM_{10}/Total $PM_{2.5}$ BACT Limits Translated to 2,437 MMBtu/hr for CT w/DB

Site	Unit	Total $PM_{10}/PM_{2.5}$ (lb/MMBtu)	Equivalent OPC Smith Limit (lb/hr)
Hanging Rock	CT	0.005	9.27
CPV 2014	CT	0.011	26.81
CPV 2018	CT	0.008	14.87
Midland	CT	0.012	22.31
Hanging Rock	CT w/ DB	0.0055	13.52
CPV 2014	CT w/ DB	0.011	26.81
CPV 2018	CT w/ DB	0.006	14.62
Midland	CT w/ DB	0.008	19.50

OPC T.A. Smith is proposing a BACT limit that, while not being the lowest value for other similarly modified units, is within the range of BACT limitations. As the operation of the SCR contributes to condensable PM formation, and OPC T.A. Smith has not been required to conduct performance testing that includes condensable PM, OPC T.A. Smith has uncertainty about the anticipated magnitude of condensable PM emissions. Based on a review of the modified units in the RBLC database, OPC T.A. Smith proposes a BACT emission limit for each CCCT system of **19.5 lb/hr** for filterable PM and total $PM_{10}/PM_{2.5}$, equivalent to an emission rate of **0.0074 lb/MMBtu**. As the OPC T.A. Smith units are presently subject to a filterable PM limit of 25 lb/hr, a limit of 19.5 lb/hr for filterable PM and total $PM_{10}/PM_{2.5}$ is a clear reduction in allowable emissions as it restricts both filterable and condensable PM emissions to a lower value, despite the increase in power output. Compliance with this BACT limit will be demonstrated by stack testing via U.S. EPA Method 5 and/or 201A in conjunction with Method 202, or alternative methods as appropriate.

Secondary BACT limits are not proposed as the particulate emissions of the turbine systems are not considered to be dependent on control measures with varying effectiveness.

The PM BACT selection for the Combustion Turbine and HRSG Duct Burner System is summarized below in Table 4-6.

Table 4-6: Applicant's Proposed PM BACT for the Combustion Turbine and HRSG Duct Burner System

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Filterable PM/Total PM_{10}/Total $PM_{2.5}$	Good Combustion and Operating Practices, and Low Sulfur Fuels	19.5 lb/hr*	hourly	Performance Test

*In subsequent negotiations, OPC has agreed to a limit of 15 lb/hr.

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

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period, and facilities that had modified the existing process. Also, with a focus of finding similar GE 7FA CTGs in use, at the facility, as possible. The Division has prepared a PM/PM_{10}/ $PM_{2.5}$ BACT comparison spreadsheet for the similar units using the above-mentioned resources.

In comparing the facility to other similarly modified units, the Division does not agree with the proposed limit of 19.5 lb/hr or 0.008 lb/mmBtu, which is close to what had been proposed for the Midland facility, and the CPV 2018 facility. The Hanging Rock facility has similarly sized GE 7FA combustion turbines that were modified. A BACT limit 0.0055 lb/MMBtu or 14.6 lb/hr (with duct burner) was set for the 2015 permit modification. The Hanging Rock facility is running, and the limit has been demonstrated with testing in 2016, using Method 5 for filterable PM, and Method 202 for condensable PM. (There was a discussion on July 16, 2019 with Anne Chamberlin, Permit Specialist, Portsmouth City Health Department, Air Pollution Unit., 605 Washington Street, 3rd Floor, Portsmouth, OH 45662.) OPC T.A. Smith was concerned that the testing was completed with the units tuned and operating just below their BACT NOx limit.

Particulate testing conducted at OPC T.A. Smith in 2002 determined a filterable particulate emission rate of 0.0034 lbs/MMBtu; this testing included both Method 5 and 5T, but accurate condensable test data was not included, so this was deemed filterable only. As the operation of the SCR contributes to condensable PM formation, and OPC T.A. Smith has not been required to conduct performance testing that includes condensable PM, Ga EPD has uncertainty about the anticipated magnitude of condensable PM emissions. Potentially comparable units in terms of lb/MMBtu for the turbine with duct burner firing, the BACT for filterable PM and total PM_{10}/$PM_{2.5}$ range is between 13.52 lb/hr to 26.81 lb/hr. Ga EPD has determined a BACT for PM and total PM_{10}/$PM_{2.5}$ of 15 lbs/hr, or equivalent to an emission rate of 0.006 lbs/MMBtu. The limit is in the lower range of the potentially comparable units and is a significant reduction from the current filterable PM limit of 25 lbs/hr.

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

In comparing the facility to other similarly modified units, the Division proposes the limit of 15 lb/hr, or equivalent to an emission rate of 0.006 lbs/mmBtu,

In the Division's review of the RBLC data reveals that the primary control technology for PM emissions are good combustion and operating practices, and low sulfur fuels such as natural gas. The results are summarized in table 4-7.

Table 4-7: PM BACT Summary for the Combustion Turbine and HRSG Duct Burner System

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Filterable PM/Total PM_{10}/Total $PM_{2.5}$	Good Combustion and Operating Practices, and Low Sulfur Fuels	15 lb/hr	hourly	Performance Test

Applicant's Proposal

Combustion Turbine and HRSG Duct Burner System NO_X Emissions

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT on NO_X emissions from each combustion turbine system, including the turbine and duct burner associated with the HRSG. The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits that are selected as BACT for NO_X.

NO_X Formation – Turbines Systems

There are five (5) primary pathways of NO_X production in gas-fired combustion turbine combustion processes: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. The three most important mechanisms are thermal NO_X, prompt NO_X, and fuel NO_X.[67] Because the turbines fire natural gas exclusively, thermal NO_X is the primary NO_X generating mechanism for the OPC T.A. Smith units.

Thermal NO_X is formed mainly via the Zeldovich mechanism where the nitrogen (N_2) and oxygen (O_2) molecules in the combustion air react to form nitrogen monoxide (NO).[68] Most thermal NO_X is formed in high temperature flame pockets downstream from the fuel injectors.[69] Temperature is the most important factor, and at combustion temperatures above 2,370°F, thermal NO_X is

[67] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[68] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[69] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

formed readily.[70] Therefore, reducing combustion temperature is a common approach to reducing NO_X emissions.

Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as hydrogen cyanide (HCN), N, and NH are oxidized to form NO_X.[71] The contribution of prompt NO_X to overall NO_X is relatively small but increases in low-NO_X combustor designs. Prompt NO_X formation is also largely insensitive to changes in temperature and pressure.[72]

Fuel NO_X forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel. Therefore, since natural gas contains little fuel bound nitrogen, fuel NO_X is not a major contributor to NO_X emissions from natural gas-fired combustion turbines.[73]

In general, technology and emissions performance data could be limited to those turbines within the size range of typical CCCT units, and specifically those size of turbines in operation at OPC T.A. Smith. U.S. EPA has, in support of federal regulations such as the NSPS for combustion turbines (NSPS Subpart KKKK), reviewed the NO_X emissions performance data for combustion turbines of all sizes and found differing performance data for turbines based on the size of the unit. As quoted by U.S. EPA, per 70 FR 8318 (2/18/05);

> *"We identified a distinct difference in the technologies and capabilities between small and large turbines…. the smaller combustion chamber of small turbines provides inadequate space for the adequate mixing needed for very low NO_X emission levels."*

U.S. EPA finalized NSPS Subpart KKKK with a breakpoint in consideration of turbine sizes greater than 850 MMBtu/hr, between 50 MMBtu/hr and 850 MMBtu/hr, and less than 50 MMBtu/hr. Since the OPC units are above the 850 MMBtu/hr size range, only units greater than 850 MMBtu/hr are truly comparable, since as identified by U.S. EPA, there are inherent design differences in units at that size and above that can lead to inherently lower NO_X emission levels. However, OPC T.A. Smith did not limit the review of RBLC entries.

NO_X emissions are a potential contributor to secondary particulate formation. Since OPC is conducting a top - down BACT analysis for NO_X for the proposed projects, secondary PM BACT is effectively addressed by controlling the direct emissions of NO_X. As such, secondary PM BACT is not separately addressed.

<u>Identification of NO_X Control Technologies – Turbine Systems</u>

NO_X reduction can be accomplished by two general methodologies: combustion control techniques and post combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce

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[70] U.S. EPA, Clean Air Technology Center, *Technical Bulletin: Nitrogen Oxides (NO_X), Why and How They are Controlled*, EPA 456/F-99-006R. November 1999.

[71] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993

[72] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[73] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

inerts (combustion products, for example) that limit initial NO_X formation, or both. Several post-combustion NO_X control technologies could potentially be employed for the OPC T.A Smith turbines. These technologies use various strategies to chemically reduce NO_X to N_2 with or without the use of a catalyst.

Detailed tables of BACT determinations from the RBLC database are provided in Appendix C of the application. Using the RBLC search, as well as a review of technical literature, potentially applicable NO_X control technologies for turbines were identified based on the principles of control technology and engineering experience for general combustion units.

Combustion control options include:[74]

- Water or Steam Injection
- Dry Low-NOx (DLN) Combustion Technology (such as SoLoNOx™)
- Good Combustion Practices (Base Case)

Post-combustion control options include:

- EMx™/SCONOx™ Technology
- Selective Catalytic Reduction (SCR)
- SCR with Ammonia Oxydation Catalyst (Zero-Slip™)
- Selective Non-Catalytic Reduction (SNCR)
- Multi-Function Catalyst ("METEOR)

Each control technology is described in detail in the following sections.

Water or Steam Injection

Water or steam injection operates by introducing water or steam into the flame area of the gas turbine combustor. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and reducing the formation of thermal NO_X. The water injected into the turbine must be of high purity such that no dissolved solids are injected into the turbine. Dissolved solids in the water may damage the turbine due to erosion and/or the formation of deposits in the hot section of the turbine. Although water/steam injection can reduce NO_X emissions by over 60%, the lower average temperature within the combustor may produce higher levels of CO and VOC as a result of incomplete combustion.[75] Additionally, water/stream injection results in a decrease in combustion efficiency, an increase in power (due to increased mass flow), and an increase in maintenance requirements due to wear.[76]

[74] An additional combustion control technology potentially identified was XONON which was offered by Catalytica Energy Systems. Catalytica merged with NZ Legacy in 2007 to form Renergy Holdings Inc. In November 2007, Renergy sold its SCR catalyst and management services business (SCR-Tech, LLC). SCR-Tech, LLC was acquired by Steag Energy Services, LLC in 2016. Based on research, there is no company which currently makes XONON. As such, it is not considered available for this BACT analysis.

[75] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[76] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

Dry Low-NOx Combustors (DLN)

The lean premix technology, also referred to as dry low-NO_X combustion technology, is a pollution prevention technology that minimizes NO_X emissions by reducing the conversion of atmospheric nitrogen to NO_X in the turbine combustor. This is accomplished by reducing the combustor temperature using lean mixtures of air and/or fuel staging or by decreasing the residence time of the combustor.[77] In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air decreases the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high temperature regions within the combustor area.[78] Since NO_X formation rates are an exponential function of temperature, a considerable reduction in NO_X can be achieved by the lean pre-mix system.[79] Depending on the manufacturer and product, different levels of control efficiencies can be achieved.

Good Combustion Practices

Good combustion practices are those, in the absence of control technology, which allow the equipment to operate as efficiently as possible. The operating parameters most likely to affect NO_X emissions include ambient temperature, fuel characteristics, and air-to-fuel ratios.

EMx™/SCONOx

EM_X™ (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_X and CO without a reagent, such as ammonia (NH_3). The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate [$K_2(CO_3)$] to oxidize NO_X (to potassium nitrate [$K(NO_3)$]) and CO (to CO_2).[80] Hydrogen (H_2) is then used as the basis for the catalyst regeneration process where $K(NO_3)$ is reacted to reform the $K_2(CO_3)$ catalyst and release nitrogen gas and water.[81] The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. The $SCONO_X$ catalyst is susceptible to fouling by sulfur if the sulfur content of the flue gas is high.[82]

Estimates of control efficiency for a $SCONO_X$ system vary depending on the pollutant controlled. California Energy Commission reports a control efficiency of 78% for NO_X reductions down to 2.0 ppm, and even higher NO_X reductions down to 1 ppm for some designs.[83]

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[77] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[78] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[79] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[80] Georgia EPD, *Prevention of Significant Air Quality Deterioration Review Preliminary Determination – Dahlberg Combustion Turbine Electric Generating Facility*, October 2009. https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/1570034pd.pdf

[81] Ibid. (Georgia EPD)

[82] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, pages 8.1E-9 and 8.1E-10.

[83] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, page 8.1E-6.

Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment process in which NH_3 is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and NO react to form diatomic N_2 and H_2O vapor. The overall chemical reaction can be expressed as:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.[84] Optimal temperatures for SCR units ranges from 480°F to 800°F, and typical SCR systems have the ability to function effectively under temperature fluctuations of up to 200°F.[85] SCR can be used to reduce NO_X emissions from combustion of natural gas and light oils (e.g., distillate). Combustion of heavier oils can produce high levels of particulate, which may foul the catalyst surface, reducing the NO_X removal efficiency.[86] Other considerations include the possibility for ammonia slip, which refers to emissions of unreacted ammonia escaping with the flue gas and its contribution to secondary particulate formation.[87]

SCR with Ammonia Oxidation Catalyst (Zero-Slip™)

SCR with Ammonia Oxidation Catalyst (Zero-Slip™) is a refinement on standard post-combustion SCR technology developed by Cormetech and Mitsubishi Power Systems to reduce ammonia slip associated with traditional SCR systems. The Zero-Slip™ technology consists of a second bed of catalyst that is installed after the main SCR catalyst to further react NO_X with the ammonia. This results in NO_X emissions on par with standard SCR systems and less ammonia slip (less than 2.0 ppmvd at 15% O_2).[88]

Selective Non- Catalytic Reduction (SNCR)

SNCR is a post-combustion NO_X control technology based on the reaction of urea or ammonia with NO_X. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the NO_X to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$
$$4\ NH_3 + 6NO \rightarrow 5\ N_2 + 6\ H_2O$$

[84] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[85] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[86] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[87] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.)

[88] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 13-14.

Typical removal efficiencies for SNCR range from 30 to 50 percent and higher when coupled with combustion controls.[89] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000 °F.[90] Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NO_X.

Multi-Function Catalyst (METEOR™)

METEOR™ is a multi-pollutant post-combustion control technology originally developed and patented by Siemens Energy Inc. and optimized by Cormetech. The METEOR™ catalyst uses ammonia, similar to standard SCR systems, to reduce NO_X emissions but is also able to reduce CO, VOC, and ammonia emissions using a single catalyst bed (i.e., eliminate the need for a separate oxidation catalyst system if CO and VOC reductions are required), resulting in reduced pressure drop and parasitic load requirements.[91] The ability of the METEOR™ catalyst to reduce NO_X emissions is on par with more traditional SCR designs.[92]

Elimination of Technically Infeasible NO_X Control Options – Turbine Systems

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control, if a control technology has not been commercially demonstrated to be achievable, or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

Water or Steam Injection Feasibility

Water or steam injection is a NO_X reduction technology that is commonly used to control NO_X emissions when fuel oil is burned, but is not as effective as DLN combustors when firing natural gas.[93] Water or steam injection also cannot be used in conjunction with DLN because it leads to unstable combustion and increases CO emissions.[94] Since the OPC T.A. Smith turbines exclusively fire natural gas and currently have DLN combustors that reduce NO_X emissions further than water or steam injection would, water or steam injection is deemed to be infeasible.

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[89] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non -Catalytic Reduction (SNCR), EPA-452/F-03-031.

[90] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non -Catalytic Reduction (SNCR), EPA-452/F-03-031.

[91] Siemens Energy and Cormetech, *Capital and O&M Benefits of Advanced Multi-Function Catalyst Technology for Combustion Turbine Power Plants*, Power Gen 2015, page 2.

[92] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 15-16.

[93] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 12

[94] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 12.

Dry Low NO_X Combustion Technology Feasibility

Dry low NO_X combustion technology is a NO_X control technology that is integral to the combustion turbine. It is determined to be technically feasible for the combustion turbine itself and is currently installed on the OPC T.A. Smith units. Therefore, DLN combustion technology is included in the following BACT steps but represents part of the base case for NO_X performance as it is inherent in the operation of the combustion systems.

Good Combustion Practices Feasibility

Good combustion practices are those that allow equipment to operate as efficiently as possible and maintain minimal emission releases with or without the operation of other control technologies. This is considered technically feasible for the minimization of NO_X emissions from the turbines.

EM ™/SCONO ™ Technology Feasibility

As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_X™/$SCONO_X$™ catalyst system has operated successfully on several smaller, natural gas-fired units, but there are engineering challenges with applying this technology to larger plants with full scale operation. To date, this technology has not been installed and operated on a large combined-cycle operation.[95] Consequently, it is concluded that EM_X™/$SCONO_X$™ is not technically feasible for control of NO_X emissions from the OPC T.A. Smith turbines.

SCR Feasibility

The OPC T.A. Smith units currently operate SCR for NO_X control. Therefore, it is considered technically feasible and included in the following BACT steps.

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

Based on OPC's review of available control technologies, to date, the Zero-Slip™ catalyst technology has not been demonstrated on large, utility-size CCCT units, with full scale operation demonstrated on a 7.5 MW Solar Taurus combustion turbine.[96] As the technology has not been demonstrated on large, utility size units, and it would not achieve NO_X emission rates lower than that achieved by conventional SCR designs (presently installed on the OPC T.A. Smith units), the Zero-Slip™ technology option is not considered a technically feasible control option.

SNCR Feasibility

The temperature range required for effective operation of this technology, 1,600 to 2,000° F, is above the peak exhaust temperature for the OPC T.A. Smith units.[97] In addition, a review of the RBLC database and AP-42's supplemental database for Chapter 3.1, *Stationary Gas Turbines*, April 2000, shows that SNCR has not been demonstrated on a turbine of this size. Given the changes to adapt units for use of SNCR, such as adding a flue gas heater, are not practical, reduces

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[95] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 14.

[96] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 14.

[97] Ibid. (SNCR Fact Sheet)

the energy efficiency of combined-cycle generating units, and would not provide control superior to the installed SCR system, SNCR is eliminated as a technically feasible option for control of NO_X emissions from the OPC T.A. Smith turbine systems.

Multi-Function Catalyst (METEOR™) Feasibility

The METEOR™ catalyst technology, developed and patented by Siemens Energy Inc., is currently only in use on one 320 MW Siemens/Westinghouse 501G combustion turbine installed in November 2015.[98,99] A review of the RBLC database for CCCT similar to OPC T.A. Smith units did not return any units that use the METEOR™ catalyst technology. As there is limited commercial operating experience with the METEOR™ catalyst, and it would not achieve NO_X emission rates lower than that achieved by conventional SCR designs (presently installed on the OPC T.A. Smith units), the METEOR™ technology option is not considered a technically feasible control option for purposes of BACT.

Summary and Ranking of Remaining NO_X Controls – Turbine Systems

Of the control technologies available for NO_X emissions, the options technically feasible for each unit are shown in Table 4-8.

Table 4-8: Remaining NO_X Control Technologies

Control Technology	Technically Feasible for Turbine Systems
Water or Steam Injection	No
DLN Combustion Technology	Yes
Good Combustion Practice	Yes
EM_X™/$SCONO_X$™ Technology	No
SCR	Yes
SCR with Zero-Slip™	No
SNCR	No
METEOR™	No

As shown in Table 4-8, the remaining feasible control technologies include SCR, DLN combustors, and good combustion practices. The OPC T.A. Smith units already operate an SCR system and utilize DLN combustors. OPC T.A. Smith will also continue to implement good combustion practices once the proposed projects are complete. Therefore, as these are the feasible controls remaining, as well as the most stringent controls, they will continue to be operated and are selected as BACT.

Selection of Emission Limits and Controls for NO_X BACT – Turbine Systems

Once the proposed modifications are complete, the combustion turbine systems will be subject to an NSPS Subpart KKKK NO_X emission standard of 15 ppm at 15% O_2 or 0.43 lb/MWh useful output. Therefore, 15 ppm at 15% O_2 serves as the floor for allowable NO_X BACT limits. Each individual combined cycle combustion turbine with HRSG and duct burner system is presently

[98] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 16.

subject to a NO_X limit of 3.0 ppm at 15% O_2 per Condition 3.3.2.a of Permit No. 4911-213-0034-V-08-0, the BACT limit established when the site was initially constructed.

As the selected BACT for NO_X emissions relies on an SCR system, DLN combustors, and good combustion practices, OPC searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas CCCT systems are provided in the RBLC summary table in Appendix C of the application. Review of the RBLC entries confirms that controls for NO_X emissions are typically SCR systems, DLN combustors, and good combustion practices for natural gas CCCT systems (or similar variants). Some entries may also denote the use of water or steam injection which was previously ruled technically infeasible for the OPC T.A. Smith units. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries provides an indication of what has been considered appropriate BACT emission limitations for potentially similar units as those being modified by OPC T.A. Smith. The majority of the RBLC database entries relate to the installation of new state-of-the-art CCCT systems, not modifications of existing CCCT units. Given the advancements in turbine design and control systems, it is not anticipated that modification of an older generation turbine system would improve combustion efficiency, controls and performance in a manner that would be comparable to installation of a new, state-of-the-art turbine and controls system. Therefore, for comparison purposes, the RBLC entries of interest for OPC T.A. Smith are ones listed as modified natural gas combustion turbine systems, summarized in Table 5-10 of the facility's PSD application (Application No. TV-343540).

The RBLC entries detailed in Table 5-10 include the same modifications at facilities that were discussed in the PM BACT analysis section with the addition of the High Desert Power Project, LLC facility in Victorville, California.[99] A review of the proposed control technologies for these facilities show that all seven required a combination of SCR, DLN combustors, and good combustion practices as BACT. OPC already operates an SCR system, DLN combustors, and implements good combustion practices on the turbine systems and will continue to operate those control systems as BACT for the turbines.

As discussed in detail in the PM BACT Analysis section, there are various factors as to why, even with the use of the same control technologies, the emissions limits presented for the facilities in Table 5-10 are not necessarily directly comparable to the OPC T.A. Smith units. Table 4-9 summarizes whether the RBLC listing was actually for a new unit or a modification of a unit, if the turbine involved was a GE turbine, and whether the facilities in Table 4-9 are comparable to the OPC T.A. Smith units based on these factors.

[99] The RBLC also included a modification at the PSO Comanche Power Station in Comanche, Oklahoma for a modification to meet a Best Available Retrofit Technology (BART) requirement. The resulting BART limit was 0.15 lb/MMBtu. As BART requirements are typically less stringent than BACT, this unit is not included for comparison

Table 4-9: Unit Comparability for NOx Assessment

Site	New/ Modified	GE Turbine?	Comparable?	NO_X Limit (ppmvd @ 15% O_2)
Hanging Rock	Modified	Yes	Yes	2.9
CPV 2014	New	Yes	Maybe	2.0
CPV 2018	Modified	Combustor Replacement	No	N/A
New Covert	Modified	No	No	N/A
Midland	New	Maybe	Maybe	2.0
Renaissance	Modified	No	No	N/A
High Desert	Modified	No	No	N/A

The Midland Cogeneration Venture has not yet occurred and the Renaissance Power, LLC project was voided. The New Covert Generating Facility and the High Desert Power Project all use non-GE combustion turbines. The CPV St. Charles facility does use GE model turbines, but a newer design (GE 7FA.05) relative to OPC T.A. Smith units. The most similar units to OPC T.A. Smith are those at the Hanging Rock facility, having initially been permitted in 2001, with a modification in 2015. Hanging Rock units presently are limited to 2.9 ppmvd of NO_X at 15% O_2 with a 3-hour block averaging period.

BACT is to be set at the lowest value that is achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. OPC maintains that although NO_X levels below 2.9 ppm at 15% O_2 can be achieved by the OPC T.A. Smith units for a majority of the time the units are operating, this standard does not meet the definition of achievable. Figure 5-1 of the facility's PSD application (Application No. TV-343540) presents a plot of the 3- hour rolling average NO_X emissions from all OPC T.A. Smith units, as measured by their CEMS, over an approximate 5- year period. An evaluation of the monitoring data, (summarized as periods with CCCT output greater than 73.6 MW, and including periods of startup and shutdown as currently evaluated for facility compliance reporting) indicates times where the NO_X levels are between 2.9 and 3.0 ppmvd at 15% O_2.[100] In fact, there are periods where emissions are above the 3.0 ppmvd at 15% O_2 limit on a 3-hour rolling average basis as shown in Figure 5-1.[101]

Figure 5-1 shows that there are presently some instances of exceedances of the current NO_X limit. While OPC T.A. Smith strives to maintain compliance with the existing 3.0 ppm NO_X limitation (currently considered by OPC T.A. Smith to include periods of startup and shutdown), there are still intermittent periods (usually following startup operations), where the combustion turbine and emissions control systems have not fully stabilized, leading to exceedances of the 3.0 ppm limit.[102] As OPC desires to maintain continuous compliance with all emission limits, any further reduction in the existing emission limit could potentially lead to an increase in the percentage of exceedances. Accordingly, OPC proposes that the BACT limit for NO_X remain at 3.0 ppmvd at 15% O_2 on a 3-hour rolling average basis, excluding periods of startup and shutdown. The existing and

[100] Current facility compliance reporting conservatively considers the 3.0 ppm @ 15% O_2 NOx emission limit to be in effect at all times, including periods of startup and shutdown, as existing permit limits do not explicitly exclude the 3.0 ppm limit during periods of startup and shutdown.

[101] Permit No. 4911-213-0034-V-08-0 Condition 3.3.7 requires that no combustion turbine be operated below 73.6 MW except during periods of startup and shutdown or during periods of special testing as authorized.

[102] OPC reports all instances of excess emissions to EPD as part of the facility's semiannual monitoring report, as required under Permit Conditions 6.1.4 and 6.1.7.

unchanged BACT limits for NO_X (lb/day, tpy) for the combined cycle combustion turbine units include periods of SUSD. OPC will continue to take all reasonable efforts to maintain as low an exceedance percentage as possible for the 3.0 ppmvd limit.

The proposed 3.0 ppmvd BACT limit is proposed, in the future, to not apply during periods of startup/shutdown. Secondary BACT limits are required given 1) that the non-steady state operations during periods of startup and shutdown result in a substantially different NO_X emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics; and 2) the SCR system is not effective during such periods before meeting its operating temperature, impacting the ability to meet the 3.0 ppmvd emission limitation. OPC T.A. Smith also proposes that the existing secondary mass rate BACT limitations, that include periods of startup and shutdown, be retained, despite the proposed energy generation increases.

The secondary BACT limitations presently include:

- Permit Condition 3.3.5.a restricts combined NO_X emissions to 279 tpy during any consecutive 12-month period from CT1/DB1 and CT2/DB2 (i.e., CCCT1 and CCCT2, which make up Block 1);
- Permit Condition 3.3.5.b restricts combined NO_X emissions to 279 tpy during any consecutive 12-month period from CT3/DB3 and CT4/DB4 (i.e., CCCT3 and CCCT4, which make up Block 2);
- Permit Condition 3.3.6 restricts each CCCT system to NO_X emissions of up to 1,153 pounds per day (24-hour period between 12:00 midnight and the following midnight.

The NOx BACT selection for the Combustion Turbine and HRSG Duct Burner System is summarized below in Table 4-10.

Table 4-10: NOx BACT Summary for the Combustion Turbine and HRSG Duct Burner System

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	SCR, DLN Combustors, and Good Combustion Practices, and Low Sulfur Fuels	3.0 ppmvd at 15% O_2 excluding startup and shutdown	3- hour rolling average basis	CEMS
		279 tpy (each Block containing 2 CCCTs)	rolling 12- months	
		1,153 lb/day (each CCCT)	daily	

EPD Review – NOx Control

EPD agrees with the following:

"The majority of the RBLC database entries relate to the installation of new state-of-the-art CCCT systems, not modifications of existing CCCT units. With the advancements in turbine design and good combustion practices, it is not likely that modification of an older generation turbine system would improve combustion efficiency, and performance in a manner that would be comparable to installation of a new, state-of-the-art turbine system. Therefore, for comparison purposes, the RBLC entries of interest for OPC T.A. Smith are other potentially modified natural gas combustion turbine systems, based on the modification designated in the RBLC entry."

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

- USEPA RACT/BACT/LAER Clearinghouse[103]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- 2015 Permit Modification for Hanging Rock, LLC, Ohio[104]
- 2018 Title V Renewal for Hanging Rock, LLC

Conclusion – NOx Control

The Division agrees with the current permit limits as per BACT limits established in 2001 for the facility. The BACT selection for the combustion turbines is summarized below in Table 4-11, and is the same as proposed by the applicant, which are the limits contained in the facility's current permit. USEPA RACT/BACT/LAER Clearinghouse (RBLC), overwhelmingly states SCR, DLN Combustors, Good Combustion Practices, and Low Sulfur Fuels as the standard control technology for natural gas-fired combined cycle combustion turbines.

Of the 31 total facilities (whether new or modified), the Division reviewed from the RBLC, over 60% had a NOx limit of 2.0 ppmvd @ 15% O_2, with either a 24-hr block average, or 3-hr block average. Of that percent, 42% indicate that this limit does not apply during startup, or shutdown. This implies that, the startup/shutdown exclusion, may be inherent with the 2.0 ppmvd @ 15% O_2 limit. This compares to the current permit limit of 3.0 ppmvd @ 15% O_2 for the facility's combustion turbines installed in 2001. The majority of the new combustion turbines have the lower NOx limit of 2.0 ppmvd @ 15% O_2.

The most similar units to OPC T.A. Smith, as they are also GE 7FA units, are at the Hanging Rock facility, having initially been permitted in 2001, with a modification in 2015, around the same time as OPC T.A. Smith for the installation and the modification permits. Hanging Rock units presently are limited to 2.9 ppmvd of NO_X at 15% O_2 with a 3-hour block averaging period.

The proposed change to the current NOx limit of 3.0 ppmvd @ 15% O_2, is that currently the limit, includes startup, and shutdown. The facility has had exceedances of this limit per Figure 5-1 of the facility's PSD application (Application No. TV-343540). The facility wishes to exclude startup and shutdown requirements from this limit. In reviewing the RBLC, there are several facilities, with a NOx limit of 2.0 ppmvd @ 15% O_2, and most exclude periods of startup and shutdown. The Division agrees with this request, and the permit will be revised to exclude periods of startup and shutdown from this limit.

Table 4-11: NOx BACT Summary for the Combustion Turbine and HRSG Duct Burner System

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	SCR, DLN Combustors, and	3.0 ppmvd at 15% O_2, not including startup/shutdown	3- hour rolling average basis	CEMS

103 http://cfpub1.epa.gov/rblc/htm/bl02.cfm

104 file:///H:/PSD/Murray/Thomas%20A.Smith%20Energy%20Facility%20-%20Dalton/TV-343540/Clearinghouse%20and%20Regulation%20Review/Hanging%20Rock,%20LLC.pdf

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
	Good Combustion Practices, and Low Sulfur Fuels	279 tpy (each Block containing 2 CCCTs)	rolling 12- months	
		1,153 lb/day (each CCCT)	daily	

Combustion Turbine and HRSG Duct Burner System – Greenhouse Gases (GHGs) Emissions

Applicant's Proposal

For PSD applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act is the sum of **six** greenhouse gases and not a single pollutant.[105] Though the primary GHG emissions from natural gas combustion at the combustion turbine systems are of carbon dioxide (CO_2), GHG BACT is discussed separately for the following additional GHG components: methane (CH_4), and nitrous oxide (N_2O).

Turbine Systems GHG Assessment

This section contains a high-level review of pollutant formation and possible control technologies for the combustion turbine systems. Though the primary GHG emissions from natural gas combustion in the combustion turbine systems are CO_2, GHG BACT is discussed separately for CH_4 and N_2O.

CO_2 production from combustion occurs in theory by a reaction between carbon in any fuel and oxygen in the air and proceeds stoichiometrically (for every 12 pounds of carbon burned, 44 pounds of CO_2 is emitted).[106] The primary component of natural gas, CH_4, can be emitted when natural gas is not burned completely.[107] The last primary component for calculating greenhouse gas emissions (in addition to CO_2 and CH_4) is N_2O. N_2O formation is limited during complete gas combustion situations, as most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a GHG.[108]

Please note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of BACT for CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a simultaneous increase in emissions of another GHG (i.e., CO_2).

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[105] The six GHGs are: CO_2, N_2O, CH_4, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

[106] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://ncdenr.s3.amazonaws.com/s3fs-public/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

[107] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*. July 1998.

[108] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://ncdenr.s3.amazonaws.com/s3fs-public/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

Turbine Systems - CO_2 BACT

The following section presents BACT evaluations for CO_2 emissions from the modified turbine systems.

Identification of Potential CO_2 Control Technologies

OPC T.A. Smith searched for potentially applicable emission control technologies for CO_2 from combustion turbines by researching the U.S. EPA control technology database, guidance from U.S. EPA and other sources such as technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The RBLC lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These results are summarized in Appendix C of the facility's PSD application (Application No. TV-343540), detailing emission levels proposed for similar types of emissions units. Based on the RBLC search, no add-on control methods for GHGs were described for any of the facilities. Many facilities listed a variant of good combustion practices, efficient operation, state-of-the-art technology (for greenfield sites), or low emitting fuels (e.g., pipeline-quality natural gas). Although not mentioned in the RBLC for any sites, energy storage technologies such as batteries are deemed to fall outside the scope of this analysis since they would essentially redefine the source.

OPC T.A. Smith used a combination of published resources and general knowledge of industry practices to generate a list of potential controls for CO_2 emitted from combustion turbine systems. OPC T.A. Smith excluded options such as battery storage or solar power generation from the GHG control technology assessment as they would redefine the business purpose of the proposed projects. OPC T.A. Smith typically operating as a high capacity factor natural gas-fired electric generating facility utilizing combined-cycle combustion turbines, maximizing utilization of the existing assets in a relatively steady-state mode of operation, with normal anticipated variations based on supply needs. U.S. EPA has affirmed that evaluation of control options or lower-emitting GHG processes, such as solar power, that would fundamentally redefine the source is not a requirement of the BACT review in their response to comments on the proposed Palmdale Hybrid Power Project, subsequently upheld in an order denying review of the PSD permit.[109]
The following potential CO_2 control strategies were considered as part of this BACT analysis:

- Carbon Capture and Storage (CCS); and
- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

These control technologies are briefly discussed in the following sections. Other CO_2 control technologies such as use of alternative fuels (with lower GHG emissions) were not considered

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[109] U.S. EPA Environmental Appeals Board decision, *In re: City of Palmdale (Palmdale Hybrid Power Project)*. PSD Appeal No. 11-07, p. 727, decided September 17, 2012, citing .S. EPA Region 9, *Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project* at 3 (Oct. 2011).

"Finally, we [EPA] note that the incorporation of the solar power generation into the BACT analysis for this facility [Palmdale] does not imply that other sources must necessarily consider alternative scenarios involving renewable energy generation in their BACT analyses. In this particular case, the solar component was a part of the applicant's Project as proposed in its PSD permit application. Therefore, requiring the applicant to utilize, and thus construct, the solar component as a requirement of BACT did not fundamentally redefine the source. EPA has stated that an applicant need not consider control options that would fundamentally redefine the source. However, it is expected that each applicant consider all possible methods to reduce GHG emissions from the source that are within the scope of the proposed project."

because they were not within the scope of the projects. OPC has already identified that pipeline-quality natural gas is the sole fuel combusted in the turbine systems.

Carbon Capture and Storage (CCS)

CCS, also known as CO_2 sequestration, involves cooling, separation and capture of CO_2 emissions from the flue gas prior to being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components needed for CCS must be technically feasible; carbon capture and compression, transport, and storage.

The first phase in CCS is to separate and capture the CO_2 gas from the exhaust stream, and then to compress the CO_2 to a supercritical condition.[110] Since most storage locations for CO_2 are greater than 800 meters deep, where the natural temperatures and pressures are greater than the critical point for CO_2, to inject CO_2 to those depths requires pressurizing the captured CO_2 to a supercritical state.

CO_2 capture can be performed via solvents or sorbents. The choice of the precise process varies with the properties of the exhaust stream. CO_2 separation has been well demonstrated in the oil and gas industries, but the characteristics of those streams are very different from a turbine system exhaust. Existing CO_2 capture technologies have not been demonstrated in the context of capturing CO_2 from large utility-scale natural gas-fired combined-cycle power plants.[111] Most combustion tests and projects have been on exhaust streams from coal combustion, which has more highly concentrated CO_2 than exhaust from natural gas combustion.

Once separated, CO_2 must be compressed to supercritical conditions for transport and storage. There are no technical challenges with compressing CO_2 to those levels, but specialized technologies with high operating energy requirements are necessary. For natural gas combined-cycle power plants, the estimated energy penalty is 15%.[112] The CO_2 could be compressed to supercritical either before or after transport.

For phase two, CO_2 would be transported to a repository. Transport options could include pipeline or truck. Specialized designs may be required for CO_2 pipelines, particularly if supercritical CO_2 is being transported. Transport of CO_2 by pipeline is a demonstrated technology, but currently most CO_2 pipelines are in rural areas. Obtaining right-of-way in developed areas is difficult.

Various CO_2 storage methods have been proposed, though only geologic storage is achievable currently. Geologic storage involves injecting CO_2 into deep subsurface formations for long-term storage. Typical storage locations would be deep saline aquifers as well as depleted or un-mineable coal seams. Captured CO_2 could also potentially be used for enhanced oil recovery via injection into oil fields.

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[110] Supercritical means that the CO_2 has properties of both a liquid and a gas. Supercritical CO_2 is dense like a liquid but has a viscosity like a gas. For additional details see https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs

[111] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 61.

[112] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, Section III, page A-14. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

As the baseline of most analyses, pollutant formation can be most cost-effectively minimized by efficient turbine operation and good combustion, operating, and maintenance practices. One of the most efficient ways to generate electricity from a natural gas fuel source is the use of a combined cycle design.[113] OPC T.A. Smith is already a combined cycle plant that solely fires pipeline-quality natural gas. The AGP Projects result in an approximate 1-2% increase in turbine system efficiency. Increased energy generation efficiency results in lower GHG emissions per MWh of electricity produced.

Within combustion units, operators can control the localized peak combustion temperature and combustion stoichiometry to achieve efficient fuel combustion. Outside of the unit, energy loss can be minimized by providing sufficient insulation to the combustion units and associated duct work.

For the purposes of this GHG control technology assessment, it is important to note that good operating practices includes periodic maintenance by abiding by an operations and maintenance (O&M) plan. Maintaining the combustion units to the designed combustion efficiency and operating parameters is important for energy efficiency related requirements and efficient operation.

Elimination of Technically Infeasible CO_2 Control Options – Turbine Systems

Carbon Capture and Storage

CCS involves cooling, separation and capture of CO_2 from the flue gas prior to the flue gas being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components (carbon capture and compression, transport, and storage) must be technically feasible.

Carbon Capture

Currently, only two options appear to be feasible for capture of CO_2 from the flue gas from the turbine systems: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that "To date, all commercial post-combustion CO_2 capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents."[114]

While Post-Combustion Membranes have been demonstrated in small scale (7,500 hours at 0.05 MW) on a coal- fired power plant with the goal of a pilot scale test at 1 MW, this technology has also not been demonstrated for flue gas control in turbine operations.[115] Although absorption technologies are currently available that may be adaptable to flue gas streams of similar character

[113] http://needtoknow.nas.edu/energy/energy-sources/fossil-fuels/natural-gas/

[114] Herzog, Meldon, Hatton, Advanced Post-Combustion CO_2 Capture, April 2009, page 7. https://sequestration.mit.edu/pdf/Advanced_Post_Combustion_CO2_Capture.pdf

[115] *New Membrane Technology for Post-Combustion Carbon Capture Begins Pilot-Scale Test*, Office of Fossil Energy, U.S. Department of Energy, January 26, 2015. https://www.energy.gov/fe/articles/new-membrane-technology-post- combustion-carbon-capture-begins-pilot-scale-test

to the flue gas from the turbine systems, to OPC T.A. Smith's knowledge, the technology has never been commercially demonstrated for flue gas control in natural gas fired turbine operations.[116]

In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects).[117] Capture-only technologies are technically available, however not yet commercially demonstrated. In addition, prior to sending the CO_2 stream to the appropriate storage site, it is necessary to compress the CO_2 from near atmospheric pressure to pipeline pressure (around 2,000 psia). The compression of the CO_2 would require a large auxiliary power load, resulting in additional fuel (and CO_2 emissions) to generate the same amount of power.[118] The auxiliary power load could be handled by installation of a separate system to solely support CO_2 compression, or alternatively be supported by reducing the available energy for sale, relying on the energy generating systems to instead meet the power needs of the compression system. This is often referred to as an "energy penalty" for operation of the CO_2 compression system.

Carbon Transport

The next step in CCS is the transport of the captured and compressed CO_2 to a suitable location for storage. This would typically be via pipeline. Pipeline transport is available and demonstrated, although costly, technology. Short CO_2 pipelines have been constructed from power plants to proposed injection wells. However, these pipelines are dedicated use for the power plants and are unavailable for other industrial sites.

Since there are no other CO_2 pipelines in the area, OPC would need to construct a CO_2 pipeline to a storage location if it were to pursue carbon sequestration as a CO_2 control option.[119] While it may be technically feasible to construct a CO_2 pipeline, considerations regarding the land use and availability need to be made. For the purposes of this analysis, it is conservatively assumed that a shortest distance pipeline can be built from a potential sequestration site to a potential carbon storage location. Realistically, a longer pipeline would be required to address land use and right-of-way considerations.

Carbon Storage

Capture of the CO_2 stream and transport are not sufficient control technologies by themselves but require the additional step of permanent storage. After separation and transport, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery, injection into

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[116] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 62.

[117] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, Section III, pages. 27-52. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

[118] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, page 29. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

[119] *A Review of the CO_2 Pipeline Infrastructure in the U.S.*, National Energy Technology Laboratory, Office of Fossil Energy, U.S. Department of Energy, April 2015. DOE/NETL-2014/1681. https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf

saline aquifers, and sequestration in un-minable coal seams, each of which are discussed as follows:

- ***Enhanced Oil Recovery (EOR)***: EOR involves injecting CO_2 into a depleted oil field underground, which increases the reservoir pressure, dissolves the CO_2 in the crude oil (thus reducing its viscosity), and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected CO_2 would flow to the surface with the oil and be captured, separated, and then re-injected. At the end of EOR, the CO_2 would be stored in the depleted oil field.

- ***Saline Aquifers***: Deep saline aquifers have the potential to store post-capture CO_2 deep underground below impermeable cap rocks.

- ***Un-Mineable Coal Seams***: Additional storage is possible by injecting the CO_2 into un-mineable coal seams. This has been used successfully to recover coal bed methane. Recovering methane is enhanced by injecting CO_2 or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releasing methane.

There are additional methods of sequestration such as direct ocean injection of CO_2, and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism for OPC T.A. Smith to permanently store the captured CO_2.

The National Energy Technology Laboratory's (NETL) Carbon Capture and Storage Database provides a summary of potential storage locations.[120] According to the database, the Black Warrior Basin of Alabama is the closest sequestration site where a test well has been drilled. The Black Warrior Basin, located Northeast of Tuscaloosa, Alabama is a pilot-scale Southeast Regional Carbon Sequestration Partnership (SECARB) CO_2 sequestration project site that has achieved an injection of 278 tons of CO_2 with the potential to sequester 1.12 to 2.32 Gigatonnes (Gt) of CO_2.[121]

The injection location is a mature coalbed methane reservoir within the Blue Creek Coal Degasification Field in Tuscaloosa County, Alabama. Figure 5-2 of the facility's PSD application (Application No. TV-343540) is a map of possible sequestration formations that have gone through SECARB's Phase II Validation program.[122] The Black Warrior Basin, listed as the Coal Seam Project near Tuscaloosa, AL on Figure 5-2, is the closest pilot or large-scale CO_2 sequestration project site to OPC T.A. Smith and is approximately 173 miles from the Facility.

OPC has concluded that CCS technology is not technically feasible at this time, based on the discussions provided. However, despite the significant technical challenges discussed earlier in

[120] Carbon Capture and Storage Database maintained by the NETL, accessed February 2019 at https://www.netl.doe.gov/coal/carbon-storage/worldwide-ccs-database

[121] *Black Warrior Basin Coal Seam Project,* SECARB. Summary document at http://www.secarbon.org/files/black-warrior-basin.pdf

[122] http://www.secarbon.org/index.php?page_id=8

implementing CCS technology on turbine systems of this size, OPC is including CCS in the next step of this analysis, although realistically technical feasibility is still unlikely.

Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are a potential control option for optimizing the fuel efficiency of the combustion turbines. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. Furthermore, the turbine systems are sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation.
Therefore, CCS and efficient turbine operation coupled with good combustion, operating, and maintenance practices are evaluated further for CO_2 BACT purposes.

Summary and Ranking of Remaining CO_2 Controls

The remaining control methods are listed below, in descending order of the expected CO_2 reductions.

- Carbon capture and storage (CCS), 90% reduction[123]
- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices, reduction efficiency is not applicable.

Evaluation of Most Stringent CO_2 Control Technologies

Carbon Capture and Storage

As the most stringent control option available, CCS would be considered BACT, barring the consideration of its energy, environmental, and/or economic impacts. However, for the reasons outlined in this section, this option should not be relied upon as BACT and the next most stringent alternative should be evaluated.

The flue gas stream from natural gas fired turbine stacks will be significantly lower in CO_2 concentration than coal fired plant exhaust streams that have demonstrated capture of CO_2 for sequestration. Natural gas fired plants have an average concentration of 3-4% CO_2 in the flue gas compared to 13-15% for coal fired plants.[124] As such, additional processing of the exhaust gas would be required to implement CCS for the proposed projects.

These steps include separation (removal of other pollutants from the waste gases), capture, and compression of CO_2, transfer of the CO_2 stream, and sequestration of the CO_2 stream. These processes require additional equipment to reduce the exhaust temperature, compress the gas, and transport the gas via pipelines. Such equipment would require additional electricity and generate additional air emissions, of both criteria pollutants and GHG pollutants. This would result in negative environmental and energy impacts.

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[123] *Estimating Carbon Dioxide Transport and Storage Costs*, National Energy Technology laboratory, U.S. DOE, DOE/NETL- 2010/1447, Page 9, March 2010.

[124] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, page 29. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

As previously discussed, a significant energy penalty is realized to achieve the capture and compression of CO_2 from the exhaust stream. Once separated, CO_2 must be compressed to supercritical conditions for transport and storage. There are no technical challenges with compressing CO_2 to those levels, but specialized technologies with high operating energy requirements are necessary. For natural gas combined-cycle power plants, the estimated energy penalty is 15%.[125] The magnitude of the energy penalty associated with implementation of CCS is a critical consideration in the context of the AGP Projects. AGP Project III is anticipated to increase the capacity of each block by approximately 28.6 MW in the summer, and 31.0 MW in the winter (Block 1 being CCCT1 and CCCT2 and steam turbine, and Block 2 being CCCT3 and CCCT4 and steam turbine). Developed cost models for various power plants have estimated that the energy costs associated with the capture requirements of CCS for a natural gas combustion turbine system are 0.354 kWh/kg of CO_2 processed.[126] Table 4-12 below presents an analysis of the impact on energy production if CCS was required as a result of the proposed projects.

Table 4-12: CCS Energy Penalty Analysis

Parameters	Value
Annual CO_2 Captured (tpy)[1]	4,567,680
CO_2 Captured (kg/yr)[2]	4,143,734,521
Proposed Project Increase in Power Output (kW)[3]	62,000
Proposed Project Increase in Power Output (MW)[3]	62
Proposed Project Increase in Energy Produced (kWh/yr)[4]	543,120,000
Proposed Project Increase in Energy Produced (MWh/yr)	543,120
Energy Used for Capture (kWh/kg CO_2 processed)[5]	0.354
Energy Used for Capture (kWh/yr)[6]	1,466,882,020
Energy Used for Capture (MWh/yr)	1,466,882
Energy Increase with Proposed Project if CCS Included (MWh/yr)	*-923,762*
Power Output Before Project (MW)	1,240
Power Output After Project (without CCS)(MW)	1,302
Power Used for Capture if CCS included (MW)[7]	167
Estimated Energy Penalty (%)	12.86%

1. Presumes 90% capture of the CO_2 emissions based on the sustainable annual capacity of the facility.
2. CO_2 Captured (kg/yr) = CO_2 Captured (tpy) * 2,000 (lb/ton) / 2.20462 (lb/kg)
3. Proposed Project Increase in Power Outpur conservatively based on the maximum anticipated winter condition increase of 31 MW per block, with two blocks operating at OPC Smith. kW = MW * 1,000 kW/MW
4. Proposed Project Increase in Energy Produced (kWh) = Proposed Project Increase in Power Output (kW) * 8,760 (hr/yr)
5. David, Jeremy and Howard Herzog, The Cost of Carbon Capture, published 2000, p. 2, accessed at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.195.9269&rep=rep1&type=pdf
6. Energy Used for Capture (kWh/yr) = Energy Used for Capture (kWh/kg CO_2 processed) * CO_2 Captured (kg/yr)
7. Power Used for Capture (MW) = Energy Used for Capture (MWh/yr) / 8,760 (hr/yr)

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[125] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, Section III, p. A-14. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

[126] David, Jeremy and Howard Herzog, *The Cost of Carbon Capture*, published 2000, p. 2, accessed at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.195.9269&rep=rep1&type=pdf

In the context of the proposed projects, the theoretical energy penalty if CCS is employed would result in a negative impact on energy generation for the proposed projects, reducing energy available for sale by an estimated 900,000 MWh/yr (presuming maximum sustainable production is maintained), an estimated 12.86% energy penalty. Therefore, OPC T.A. Smith would have no incentive to pursue the proposed projects, which results in an increase in energy generation efficiency for the existing combustion turbine systems, if OPC T.A. Smith were required to utilize CCS for GHG emission reductions.

A detailed cost analysis related to the installation of CCS has not been provided considering the substantial negative energy penalty associated with CCS. Realistically, OPC T.A. Smith would also not be able to secure financing necessary for the capital intensive costs associated with CCS systems, in light of the fact that OPC T.A. Smith could not demonstrate a financial benefit (i.e., increased electricity for sale) if CCS were required.[127],[128] Current estimates indicate that the capital cost alone for a CCS system for the OPC T.A. Smith facility could cost in excess of $500 million dollars.

Given the negative energy and economic considerations, as well as the technical challenges associated with implementing CCS, it is deemed infeasible and eliminated as a viable option for BACT.

Selection of CO_2 BACT

CO_2 BACT for these projects includes efficient turbine operation coupled with good combustion, operating, and maintenance practices. As mentioned previously, the resulting BACT standard is an emission limit unless technological or economical limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

BACT determinations for similar combined-cycle generating units, as detailed in the RBLC summary tables in Appendix C of the application denote energy efficiency, good design and good combustion practices as BACT. Post-combustion capture and sequestration of CO_2 is not required. BACT limits for natural gas combined-cycle units can be found expressed in terms of lb/MWh, Btu/kWh, or tons, typically with a 12-month rolling total averaging period.

Focusing on modified units given anticipated similarities in performance and possible combustion efficiencies, Table 4-13 summarizes the applicable GHG BACT limit, presenting an equivalent limit for the OPC T.A. Smith units in terms of tons per year. In addition, the CO_2 emission limit per NSPS Subpart TTTT for constructed or reconstructed combined-cycle combustion turbines is

[127] CCS has high capital and operating costs. Capital costs for natural gas combined cycle plants with CCS have increased capital costs of $340 million dollars (2010 dollars) relative to plants without CCS, per the *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, Section III, page A-14. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

[128] Detailed discussion of capital and operating costs associated with CCS, including the influence of the magnitude of the capital costs for CCS relative to the total capital costs for proposed construction of the new electric generating facility. Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to *Step 4: Evaluate the Most Effective Controls* for GHG, Attachment B pages 65 - 70.

also presented for comparison, although the OPC T.A. Smith units are not subject to the emission limitations per NSPS Subpart TTTT.

Table 4-13: CO_2 Limit Review

Site	Limit for Turbine with Duct Burner	Units	Equivalent OPC Smith Unit Limit (tpy)[1]
CO_2 Limits			
NSPS Subpart TTTT	1,000	lb/MWhr gross output	1,425,690
CPV 2018	878	lb/MWhr gross output	1,251,756
CO_2e Limits			
Midland	1,071	lb/MWhr gross output	1,526,914
Modified Units with no output-based limit for CT w/ DB			
Hanging Rock	Permit action did not trigger PSD, therefore GHG BACT not required.		
CPV 2014	Permit action included tpy GHG BACT or CT only BACT value.		
New Covert	Permit action included tpy GHG BACT		

1. Maximum Output for OPC-Smith facility post-project:

Facility Total:	1,302	MW
Output from each CCCT system:	325.5	MW

Table 4-14 summarizes OPC T.A. Smith's GHG emission quantification for post-project operations, detailing the maximum annual emissions based on the anticipated operating capacity for sustainable operation.

Table 4-14: OPC T.A. Smith GHG Emission Quantification

GHG	Emission Factor[1, 2] (lb/MMBtu)	Maximum Annual Operating Capacity[3] (Million MMBtu/yr)	Maximum Annual Emissions[4] (tpy)
CO_2	118.86	85.4	5,075,200
CH_4	2.20E-03	85.4	94.1
N_2O	2.20E-04	85.4	9.41
Total GHG emissions (CO_{2e})[5]			**5,080,359**
Each Unit (i.e., one gas turbine and one HRSG with duct burner)			**1,270,090**

1. CO_2 Emission factor derived per Appendix G to 40 CFR Part 75, Section 2.3. CO_2 (lb/MMBtu) = 1,040 scf/MMBtu * 44.0 lb/lb-mole / 385 scf CO_2/lb-mole
2. CH_4 and N_2O emissions factors per Part 98, Subpart C, Table C-2. kg/MMBtu factors converted to lb/MMBtu multiplying by 2.20462 lb/kg
3. Maximum Annual Operating Capacity anticipated for sustainable operation.
4. Emissions (tpy) = EF (lb/MMBtu) * Maximum Annual Operating Capacity (Million MMBtu/yr) * 1E6 MMbtu/ Million MMBtu / 2,000 lb/ton
5. Total GHG emissions in CO2e is the sum of the product of each GHG and its respective global warming potential (GWP) per 40 CFR Part 98 Subpart A, Table A-1, effective January 1, 2014.

Pollutant	GWP
CO_2	1
CH_4	25
N_2O	298

The potential CO_2e annual emissions for each combined-cycle combustion turbine with HRSG and duct burner are estimated to be 1,270,090 tpy post-project.[129] Note that estimated CO_2 emissions comprise 99.9% of the CO_2e emissions. Based on a comparison to other modified units, OPC T.A. Smith's annual CO_2e emissions represents an achievable BACT performance level to ensure on-going compliance. While the CPV 2018 limit for CO_2 denoted in Table 4-13 is slightly lower, it is important to remember that the CPV 2018 modification proposed changes to the DLN combustors (complete replacement) which reduces the similarity to the proposed OPC T.A. Smith AGP modifications. OPC T.A. Smith's proposed CO_2e 12-month rolling total emissions is less than the equivalent annual emissions predicted if the NSPS Subpart TTTT limit of 1,000 lb/MWh gross output were relied upon for derivation of annual emissions based on the potential OPC T.A. Smith gross output capacity post- project (i.e., 1,302 MW site-wide or 325 MW per CCCT system).

Therefore, OPC T.A. Smith proposes a total CO_2e BACT emission limit of 1,270,090 tons per year for each turbine and associated duct burner systems. The proposed emission limits are based on 12-month rolling total basis and includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions representing 99.9% of the total GHG emissions.

Compliance with the proposed BACT limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with those presented in Table 4-14. Specifically, the monthly CO_2e emissions will be calculated based on the monthly fuel use, the CO_2 emission factor from Appendix G to 40 CFR 75, the CH_4 and N_2O emission factors from Subpart C to 40 CFR 98, and the current GWPs from Subpart A to 40 CFR 98 (1 for CO_2, 25 for CH_4, and 298 for N_2O). These calculations will be performed on a monthly basis to ensure that the 12- month rolling total tons per year emission rate does not exceed this limit.

Through this proposed BACT limit, OPC T.A. Smith limits the maximum fuel consumption and CO_2e emissions, effectively requiring efficient operation at the design heat rate, when operating at 100% load (as inefficient turbine operation would require additional fuel consumption which is undesirable from an operator's perspective).

Turbine Systems CH_4 BACT

CH_4 emissions from the natural gas-fired combustion turbines form as a result of incomplete combustion of hydrocarbons present in the natural gas fuel.

Identification of Potential CH_4 Control Technologies

The only available control options for minimizing CH_4 emissions from the combustion turbine systems are efficient turbine operation coupled with good combustion, operating, and maintenance practices to minimize unburned fuel. Oxidation catalysts are not considered available for reducing CH_4 emissions because oxidizing the very low concentrations of CH_4 present in the combustion turbine's exhaust would require much higher temperatures, residence times, and catalyst loadings than those offered commercially for CO oxidation catalysts. For these reasons, catalyst providers do not offer products for reducing CH_4 emissions from gas-fired combustion turbines.

[129] CO_2 mass calculations based on methodologies per the Acid Rain Program, 40 CFR 75 Appendix G. Mass emissions for CH_4 and N_2O are based on emission factors per the GHG Mandatory Reporting Rule, 40 CFR 98 Subpart C, Table C-2. Conversion to CO_2e is based on the global warming potentials (GWP) per 40 CFR 98 Subpart A, Table A-1.

Technically Infeasible CH_4 Control Options

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are the only technically feasible control options for reducing CH_4 emissions from the combustion turbines.

No adverse energy, environment, or economic impacts are associated with efficient turbine operation and good combustion, operating, and maintenance practices for reducing CH_4 emissions from the combustion turbine.

Selection of CH_4 BACT

Efficient turbine design and good combustion, operating, and maintenance practices are the selected control options for minimizing CH_4 emissions from the combustion turbine systems. OPC has determined that a numerical limit for CH_4 is unnecessary, and that the work practices required for CO_2 BACT (i.e., monthly fuel consumption monitoring and emissions calculations), and efficient turbine operation coupled with good combustion, operating, and maintenance practices, are sufficient for CH_4 BACT, in addition to the aforementioned CO_2e limit. The CH_4 portion of the proposed CO_2e BACT limit will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 25 (per 40 CFR 98 Subpart A, rule effective January 1, 2014).

Turbine Systems N_2O BACT

For the proposed projects, the contribution of N_2O to the total CO_2e emissions is trivial and therefore should not warrant a detailed BACT review. Nevertheless, the additional information provided supports the rationale that the proposed projects meet BACT for contributions of N_2O to CO_2e.

A tradeoff between NO_X and N_2O emissions from the combustion turbines exists when developing a combustion control strategy which influences the BACT selection process. There are five (5) primary pathways of NO_X production in gas-fired combustion turbine combustion processes: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. For turbines using DLN combustors, the N_2O pathway is an important mechanism of NO_X formation. Flame radicals produced in the high temperature and pressure DLN combustion zone react with the N_2O molecule, creating N_2 and NO.[130] In premixed gas flames, N_2O is primarily formed in the flame front or oxidation zone. Once formed, the N_2O is readily destroyed due to the relatively high concentration of H radicals, and therefore, the N_2O emissions from premixed gas flames like DLN combustor flames are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms which decrease the H atom concentration in the N_2O formation zone can increase N_2O emissions. These mechanisms include lowering the flame combustion temperature, air-to-fuel staging, and injection of ammonia, urea, or other amine or cyanide species into the exhaust stream which are all common NO_X control measures.[131] Therefore, there is a tradeoff between NO_X and N_2O emissions when developing a combustion control strategy which influences the BACT selection process.

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[130] Angello, L., Electric Power Research Institute, Fuel Composition Impacts on Combustion Turbine Operability, March 2006.

[131] American Petroleum Institute, Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, February 2004.

Identification of Potential N_2O Control Technologies

N_2O catalysts are a potential control option, as these have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[132] Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst.

Technically Infeasible N_2O Control Options

N_2O catalyst providers do not offer products to control N_2O emissions from gas-fired combustion turbines due to the very low N_2O concentrations present in exhaust streams (approximately 5 ppm).[133] In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N_2O concentration in the exhaust stream. With N_2O catalysts eliminated, good combustion practice is the only available control option.

Good combustion practices are technically feasible control options for reducing N_2O emissions from the combustion turbines.

Evaluation of Most Stringent N_2O Control Technologies

As indicated in U.S. EPA's guidance on GHG BACT, GHG control strategies may have the potential to produce higher criteria pollutants as in the case of the competing NO_X and N_2O combustion control strategies for OPC T.A. Smith's combustion turbine systems. In such cases, the guidance suggests that the applicant should consider the effects of increases in emissions of other regulated pollutants that may result from the use of that GHG control strategy, and based on this analysis, the permitting authority can determine whether or not the application of that GHG control strategy is appropriate given the potential increases in other pollutants.[134]

Given the low N_2O emissions relative to NO_X emissions from the combustion turbine systems and U.S. EPA's continued concern over adverse impacts from ozone formation due to NO_X and VOC emissions, OPC does not consider it appropriate to control the combustion processes of the combustion turbine to specifically reduce N_2O emissions due to the counteractive increase in NO_X emissions. Therefore, good combustion practice for the specific purpose of minimizing N_2O formation is eliminated based on adverse criteria pollutant impacts.

Selection of N_2O BACT

Efficient turbine design and general good combustion, operating, and maintenance practices are the selected control options for reducing N_2O emissions from the combustion turbines. OPC has determined that a numerical limit for N_2O emissions is unnecessary and that the work practices required for CO_2 BACT (i.e., monthly fuel consumption monitoring and emissions calculations), and efficient turbine operation coupled with good combustion, operating, and maintenance practices, are sufficient for N_2O BACT, in addition to the aforementioned CO_2e limit. The N_2O

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[132] *N_20 Emissions from Adipic Acid and Nitric Acid Production*, written by Heike Mainhardt (ICF Incorporated) and reviewed by Dina Kruger (U.S. EPA). http://www.ipcc-nggip.iges.or.jp/public/gp/bgp/3_2_Adipic_Acid_Nitric_Acid_Production.pdf

[133] *Emissions of Nitrous Oxide from Combustion Sources,* in Progress and Energy and Combustion Science 18(6): pages 529- 552 , December 1992, found at: https://www.researchgate.net/publication/223546823_Emissions_of_nitrous_oxide_from_combustion_sources

[134] *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 39.

portion of the proposed CO_2e BACT limit will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 298 (per 40 CFR 98 Subpart A, rule effective January 1, 2014).

The GHG BACT selection for the Combustion Turbine and HRSG Duct Burner System is summarized below in Table 4-15:

Table 4-15: BACT Summary for the Combustion Turbine and HRSG Duct Burner System

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
GHGs[1]	Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices	1,270,090 tpy CO_2e (each CCCT)[135]	rolling 12-months	Records of Fuel Usage

1. Total GHG emissions in CO_2e is the sum of the product of each GHG and its respective global warming potential per 40 CFR Part 98 Subpart A, Table A-1, as stated in Table 4-14.

EPD Review – Greenhouse Gases (GHGs) Control

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

- USEPA RACT/BACT/LAER Clearinghouse[136]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- 2015 Permit Modification for Hanging Rock, LLC, Ohio[137]
- 2018 Title V Renewal for Hanging Rock, LLC

The Division has prepared a GHG BACT comparison spreadsheet for the similar units using the above-mentioned resources.

Conclusion – Greenhouse Gases (GHGs) Control

The BACT selection for the combustion turbines is summarized below in Table 4-16, and is the same as proposed by the applicant. USEPA RACT/BACT/LAER Clearinghouse (RBLC), overwhelmingly states Efficient Turbine Operation, and Good Combustion, Operating, and Maintenance Practices as the standard control technology for natural gas-fired combined cycle combustion turbines.

Of the 27 total facilities (whether new or modified), the Division reviewed from the RBLC, approximately 33% (9 facilities) had an annual rolling 12-month GHG BACT limit in tons per year, with one facility have a 365-day rolling average (Deer Park Energy Center). Of that percent 66% of the facilities were of a comparable size, ranging from 930 MW to 1230 MW. The two

[135] Calculation is ((118.86 lb/MMbtu*85.4 Million MMBtu/yr*1E6 MMbtu/Million MMBtu/2,000 lb/ton)*1 for CO_2 +(2.20E-3 lb/MMbtu*85.4 Million MMBtu/yr*1E6 MMbtu/Million MMBtu/2,000 lb/ton)*25 for CH_4) + (2.20E-4 lb/MMbtu*85.4 Million MMBtu/yr*1E6 MMbtu/Million MMBtu/2,000 lb/ton)*298 for N_2O))/4. See Table 4-14 for emission factor calculations.

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

[137] file:///H:/PSD/Murray/Thomas%20A.Smith%20Energy%20Facility%20-%20Dalton/TV-343540/Clearinghouse%20and%20Regulation%20Review/Hanging%20Rock,%20LLC.pdf

closest facilities based on size, is Tenaska PA Partners/Westmoreland Generating Facility sized at 1065 MW. This is a new facility and has a 1,881,905 tpy GHG gas limit for 1 CCCT unit. The other is Harrison Power sized at 1000 MW. This also is a new facility and has a 1,249,910 tpy GHG gas limit for 1 CCCT unit. These limits compare to OPC T.A. Smith's GHG limit of 1,270,090 tpy for 1 CCCT unit.

Rolling Hills Generating plant is permitted for Siemens Westinghouse Power Corp. SW501F units This modified facility of similar size and timeframe has a 1,293,743 tpy GHG gas limit for 1 CCCT unit.

Another modified facility is CPV St. Charles facility as mentioned in previous BACT analyses. This facility has a 1,332,957 tpy GHG gas limit for 1 CCCT unit.

OPC T.A. Smith limit is higher (in the range of 16% to 33%) than the newer units, but that is to be expected, as discussed previously, a new design technology should be more efficient. As in comparison to the modified facilities OPC T.A. Smith's GHG limit of 1,270,090 tpy for 1 CCCT unit is lower (5 to 12%) to in both cases. Giving this information, the Division agrees with OPC T.A. Smith's GHG proposed limit of 1,270,090 tpy.

The BACT selection for the Combustion Turbine and HRSG Duct Burner System is summarized below in Table 4-16:

Table 4-16: BACT Summary for the Combustion Turbine and HRSG Duct Burner System

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
GHGs[1]	Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices, Pipeline quality natural gas	1,270,090 tpy CO_2e (each CCCT)[138]	rolling 12-months	Records of Fuel Usage

1. Total GHG emissions in CO_2e is the sum of the product of each GHG and its respective global warming potential per 40 CFR Part 98 Subpart A, Table A-1, as stated in Table 4-14.

[138] Calculation is ((118.86 lb/MMbtu*85.4 Million MMBtu/yr*1E6 MMbtu/Million MMBtu/2,000 lb/ton)*1 for CO_2 +(2.20E-3 lb/MMbtu*85.4 Million MMBtu/yr*1E6 MMbtu/Million MMBtu/2,000 lb/ton)*25 for CH_4) + (2.20E-4 lb/MMbtu*85.4 Million MMBtu/yr*1E6 MMbtu/Million MMBtu/2,000 lb/ton)*298 for N_2O))/4. See Table 4-14 for emission factor calculations.

5.0 TESTING AND MONITORING REQUIREMENTS

Testing Requirements:

Compliance with the BACT emission limit for each CCCT system of 15 lb/hr for filterable PM and total PM_{10}/$PM_{2.5}$, equivalent to an emission rate of 0.0062 lb/MMBtu will be demonstrated by stack testing via U.S. EPA Method 5 and/or 201A in conjunction with Method 202 or alternative methods as appropriate.

Monitoring Requirements:

Presently, the combustion turbines are subject to NSPS Subpart GG. However, upon completion of the proposed modifications, the combustion turbine systems will be subject to the more recently promulgated standards for Stationary Combustion Turbines under NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(b) (NSPS Subpart KKKK), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. Therefore NSPS Subpart GG will no longer apply to the OPC T.A. Smith combustion turbines following the proposed project.

Pursuant to 40 CFR 60.4333(a), the combustion turbines, air pollution control equipment, and monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction.

Compliance with the proposed GHG BACT limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with those presented in Table 4-14. The facility currently has Condition No. 6.2.4 in the permit that require monthly recordkeeping of natural gas usage in each combustion turbine.

Specifically, the monthly CO_2e emissions will be calculated based on the monthly fuel use, the CO_2 emission factor from Appendix G to 40 CFR 75, the CH_4 and N_2O emission factors from Subpart C to 40 CFR 98, and the current GWPs from Subpart A to 40 CFR 98 (1 for CO_2, 25 for CH_4, and 298 for N_2O). These calculations will be performed on a monthly basis to ensure that the 12- month rolling total tons per year emission rate does not exceed this limit.

NO_X Compliance Demonstration Requirements

The combustion turbine systems presently employ a continuous emission monitoring system (CEMS) for NO_X per the requirements of the Acid Rain Program (ARP), promulgated in 40 CFR Part 75. Pursuant to 40 CFR 60.4340(b)(2)(iv), with state approval OPC T.A. Smith can rely on the methodologies per 40 CFR Part 75 Appendix E to demonstrate ongoing compliance with the NSPS Subpart KKKK NO_X emission limits. Sources demonstrating compliance with the NO_X emission limit via CEMS are not subject to the requirement to perform initial and annual NO_X stack tests.[139] Initial compliance with the NO_X emission limit will be demonstrated by comparing the arithmetic average of the NO_X emissions measurements taken during the initial relative

[139] 40 CFR 60.4340(b), 40 CFR 60.4405

accuracy test audit (RATA) required pursuant to 40 CFR 60.4405 to the NO_X emission limit under this subpart.[140]

SO_2 Compliance Demonstration Requirements

For compliance with the SO_2 emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by EPD;[141] however, OPC T.A. Smith elects to opt out of this provision of the rule by using a fuel that is demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO_2.[142] This demonstration can be made using one of the following methods:

1. By using a purchase contract specifying that the fuel sulfur content for the natural gas is less than or equal to 20 grains of sulfur per 100 standard cubic feet and results in potential emissions not exceeding 0.060 lb/MMBtu.

2. By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4 which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input.

OPC is currently required to monitor the sulfur content of the natural gas burned in the combustion turbines and duct burners through submittal of a semiannual analysis of the gas by the supplier or the facility to demonstrate that the sulfur content does not exceed its excursion threshold of 0.2 grains per 100 standard cubic feet.[143] This sulfur content analysis by the supplier or OPC T.A. Smith satisfies the sulfur content demonstration methodologies in 40 CFR 60.4365(a) and (b), respectively. Therefore, continued compliance with these existing permit conditions will guarantee compliance with these NSPS KKKK requirements.

CAM Applicability:

Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Although other units may potentially be subject to CAM upon renewal of the Title V operating permit, such units are not being modified under the proposed project and need not be considered for CAM applicability at this time.

Each combustion turbine/duct burner stack is equipped with an SCR to reduce NO_X emissions. In addition, these units have NO_X CEMS to verify proper operation. The combustion turbines are

[140] 40 CFR 60.4405(c)

[141] 40 CFR 60.4370(b) and (c)

[142] 40 CFR 60.4365

[143] Permit No. 4911-213-0034-V-08-0, Conditions 6.2.1, 6.2.2, and 6.1.7.c.i

currently complying with the CAM plan included in Conditions 5.2.7 through 5.2.8 of Permit No. 4911-213-0034-V-08-0, which was derived through previously submitted CAM plans as part of prior historic permitting actions. At this time, no changes to the existing CAM requirements are requested. Therefore, no CAM documentation has been included within this permit application.

6.0 AMBIENT AIR QUALITY REVIEW

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

The proposed project at the OPC T.A. Smith triggers PSD review for filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e). An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e). An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

Modeling Requirements

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

The proposed project will cause net emission increases of filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e) that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e) emissions increases at the OPC T.A. Smith would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 6-1.

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

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for the filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e).

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the facility are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. $PM_{2.5}$ does have established SILs per an EPA finalized memo (April 2018) which recommended use of a 24-hr $PM_{2.5}$ SIL of 1.2 ug/m^3, and an annual SIL of 0.2 ug/m^3. However, the guidance indicated that the permitting authority had the discretion to continue to utilize the previously established annual SIL of 0.3 ug/m3. EPA responded to the existing vacature of the SMCs by indicating that existing background monitors should be sufficient to fulfill the ambient monitoring requirements for $PM_{2.5}$.

Table 6-1: Summary of Modeling Significance Levels

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

Table 6-1A: Results of modeling compared to Monitoring levels

Criteria Pollutant	Averaging Period	*Significant Monitoring* Concentration	Maximum Projected Concentration*	Receptor UTM Zone: <u>16</u>		Exceeds SMCs?
		(μg/m^3)	(μg/m^3)	Easting (meter)	Northing (meter)	
PM_{10}	24-Hour	10	1.02	681,814.00	3,842,987.10	No
NO_2	Annual	14	0.27	690,514.00	3,843,487.10	No

NAAQS Analysis

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS are listed in Table 6-2 below.

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

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
PM_{10}	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
$PM_{2.5}$	Annual	12 / 12	--
	24-Hour	35 / 35	--
NO_2	Annual	100 / 100	0.053 / 0.053
NO_2	1-Hour	188	

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

PSD Increment Analysis

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

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

Table 6-3: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
PM_{10}	Annual	4	17
	24-Hour	8	30
PM2.5	Annual	1	4
	24-Hour	2	9
NO_X	Annual	2.5	25

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

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NO_X is February 8, 1988, and the major source baseline for SO_2 and PM_{10} is January 5, 1976. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for PM_{10} and SO_2 as January 30, 1980, NO_2 as April 12, 1991, and $PM_{2.5}$ as October 20, 2011 (trigger date).

Modeling Methodology

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

Modeling Results

Table 6-4 show that the proposed project will cause ambient impacts of NO_2 (1 hour), and $PM_{2.5}$ (annual) above the appropriate SIL. Cumulative modeling including sources identified using the Georgia EPD PSD Inventory Tool and Georgia EPD-provided background concentrations were used.

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

Criteria Pollutant	Averaging Period	Significant Impact Level	Maximum Projected Concentration*	Receptor UTM Zone: 16		Exceeds SIL?	Radius of the SIA
		($\mu g/m^3$)	($\mu g/m^3$)	Easting (meter)	Northing (meter)		(km)
NO_2	Annual	1	0.27	690,514.00	3,843,487.10	No	N/A
	1-Hour+	7.5	28.7	681,944.70	3,843,797.00	**Yes**	**8.7**
PM_{10}	Annual	1	0.22	690,514.00	3,843,487.10	No	N/A
	24-Hour	5	1.02	681,814.00	3,842,987.10	No	N/A
$PM_{2.5}$	Annual#	0.2	0.25	690,514.00	3,843,487.10	**Yes**	**0.6**
	24-Hour#	1.2	1.05	690,914.00	3,842,387.10	No	N/A

As indicated in the tables above, maximum modeled impacts were below the corresponding SILs for PM_{10}. However, maximum modeled impacts were above the SILs for NO_2 (1 hour), and $PM_{2.5}$ (annual). Therefore, a Full Impact Analysis was conducted for these two pollutants.

Significant Impact Area

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

NAAQS and Increment Modeling

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the facility's SIA are ideally included in this regional inventory. OPC Thomas A Smith used the PSD Inventory Tool to receive an inventory of NAAQS and PSD Increment sources from Georgia EPD. OPC reviewed the data received and calculated the distance from the plant to each facility in the inventory. All sources more than 50km beyond the facility were excluded.

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

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

NAAQS Analysis

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

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

Table 6-5: NAAQS Analysis Results

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Background (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
NO2	1-Hour	682,245	3,850,097	115.4	30.3	145.7	188	No
PM2.5	Annual	690,514	3,843,487	0.004	8.4	9.33	12	No

Data for worst year provided only.

Increment Analysis

The modeled impacts from the NAAQS run were evaluated to determine whether compliance with the Increment was demonstrated for the pollutant and averaging period above the SIL ($PM_{2.5}$). The results are presented in Table 6-6.

Table 6-6: Increment Analysis Results – Class II Annual $PM_{2.5}$

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
PM2.5	Annual	690,514	3,843,487	1.1	4	No

Data for worst year provided only

Table 6-6 demonstrates that the impacts are below the corresponding increments for $PM_{2.5}$ (annual). This includes $PM_{2.5}$ derived from MERP

Ambient Monitoring Requirements

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

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
NO_2	Annual	690,514	3,843,487	14	0.27	No
PM_{10}	24-hour	681,814	3,842,987	10	1.02	No

Data for worst year provided only

The impacts for NO_X, $PM_{2.5}$, and PM_{10} quantified in Table 6-4 of the Class I Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 6-1, to determine if ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding de minimis concentrations, no pre-construction monitoring is required for NO_2, PM_{10}, $PM_{2.5}$.

As noted previously, the VOC *de minimis* concentration is mass-based (100 tpy) rather than ambient concentration-based (ppm or μg/m^3). Projected VOC emissions increases resulting from the proposed modification is less than 100 tpy.

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define “near”, but more recently, a distance of 300 kilometers has been used for all facilities.

Seven Class I areas exist within a 300 km range from the OPC Smith facility: Cohutta Wilderness (GA), Joyce Kilmer-Slickrock Wilderness (TN), Great Smoky Mountains National Park (TN), Shining Rock Wilderness (NC), Sipsey Wilderness (AL), Mammoth Cave National Park (KY), and Linville Gorge Wilderness (NC). The National Park Service and the USDA Forest Service are responsible for oversight of all seven of these Class I areas.

Table 6-8. Project Impacts and Significant Impact Levels (Class I Areas).

Criteria Pollutant	Averaging Period	Significance Level	Maximum Projected Concentration*	Receptor UTM Zone: 16		Exceeds SIL?
		(μg/m^3)	(μg/m^3)	Easting (meter)	Northing (meter)	
NO_2	Annual	0.1	0.081	715,010.77	3,868,445.20	No
PM_{10}	Annual	0.2	0.040	715,010.77	3,868,445.20	No
	24-Hour	0.3	0.262	715,010.77	3,868,445.20	No
$PM_{2.5}$	Annual	0.05	0.046	715,010.77	3,868,445.20	No
	24-Hour	0.27	0.135	715,010.77	3,868,445.20	No

* Highest concentration over all averaging period

7.0 ADDITIONAL IMPACT ANALYSES

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

Soils and Vegetation

To address the potential soil and vegetation impacts, the applicant adopted the NAAQS analysis presented above because EPA recently proposed to use the secondary NAAQS standards for such analysis. Note that annual and 24-hour PM_{10}, 24-hour $PM_{2.5}$, and annual NO_2 were not significant in comparison with their respective SILs. Table 7-1 shows the total potential impacts of 1-hour NO_2 and annual $PM_{2.5}$ are all below their respective screening threshold levels. Therefore, no detrimental effects on soil or vegetation are expected from the proposed facility.

In addition, emissions from the proposed facility were compared to the significant emission rates according to the US EPA guidance document "*A Screening Procedure for the Impact of air Pollution Sources on the Plants, Soils, and Animals*" (December 1980). Potential annual emissions from the proposed facility are all below the significant emission rates in the guidance.

Table 7-1. CLASS II AREA Vegetative Impact Results (AERMOD with downwash)

Pollutant	**Averaging Period**	**All Source Impact ***	**Background Concentration**	**Total Potential Impact***	**Screening Level+**	**Exceed Screening Level?**
		(μg/m³)	**(μg/m³)**	**(μg/m³)**	**(μg/m³)**	
NO_2	1-hour	115.4	30.3	145.7	188	No
$PM_{2.5}$	Annual	0.93	8.4	9.33	12	No

* NAAQS results including both project and offsite inventories. A total impact is a sum of the predicted concentration plus the background concentration.

Growth

The changes proposed to OPC TA Smith will have little effect on growth, jobs, or construction.

Visibility

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

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

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

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

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

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

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

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

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

Visibility can be affected by plume impairment or regional haze. Plume impairment occurs when there is a contrast or color difference between the plume and a viewed background. Plume impairment is generally only of concern when the Class I area is near the proposed source (less than 50 km). Since the distance between the OPC Smith facility and the Cohutta Wilderness is 30.6 km, plume impairment was considered. The applicant utilized the VISCREEN model to estimate plume blight at the nearest Class I receptor location as well as at a distance of 50 km to ensure that plume impairment will remain at acceptable levels. A level 2 analysis was performed, using the worst-case 1% meteorological conditions along with all other level 1 default values in VISCREEN. The worst-case 1% meteorological conditions were determined for over 5 years of representative meteorological data from Chattanooga, TN. The combination of stability class "C" and wind speed of 3 m/s yields the 1.03% cumulative frequency condition. Therefore, the evaluation of plume blight showed no issues with visibility based on impacts for the Cohutta Wilderness Class I area.

Georgia Toxic Air Pollutant Modeling Analysis

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

Selection of Toxic Air Pollutants for Modeling

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

For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*.

Determination of Toxic Air Pollutant Impact

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

Initial Screening Analysis Technique

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

Table 7-2 summarizes the AAC levels and MGLCs of the thirteen TAPs. The maximum 15-minute impact is based on the maximum 1-hour modeled impact multiplied by a factor of 1.32. As shown in Table 7-2, the modeled MGLCs for all thirteen TAPs are below their respective AAC levels.

Table 7-2. Modeled MGLCs and the respective AACs.

Pollutants	CAS	Averaging period	MGLC* (μg/m^3)	AAC (μg/m^3)	Exceed AAC?	Averaging period	MGLC* (μg/m^3)	AAC (μg/m^3)	Exceed AAC?
Acetaldehyde	75070	Annual	8.69E-03	4.55E+00	No	15-min	1.17E+00	4.50E+03	No
Acrolein	107028	Annual	2.10E-04	2.00E-02	No	15-min	1.45E-02	2.30E+01	No
Ammonia	7664417	Annual	3.45E-01	1.00E+02	No	15-min	2.42E+01	2.40E+03	No
Arsenic	7440382	Annual	1.00E-05	2.33E-04	No	15-min	1.85E-04	2.00E-01	No
Barium	7440393	24-hour	9.30E-04	1.19E+00	No				
Benzene	71432	Annual	4.20E-04	1.30E-01	No	15-min	2.89E-02	1.60E+03	No
1.3-Butadiene	106990	Annual	1.00E-05	3.00E-02	No	15-min	9.77E-04	1.10E+03	No
Cadmium	7440439	Annual	4.00E-05	5.56E-03	No	15-min	9.90E-04	3.00E+01	No
Chromium	7440473	Annual	5.00E-05	8.30E-05	No	15-min	1.27E-03	1.00E+01	No
Formaldehyde	50000	Annual	6.21E-03	7.70E-01	No	15-min	4.11E-01	2.45E+02	No
Nickel	7440020	24-hour	4.40E-04	7.94E-01	No				
Propylene Oxide	75569	Annual	9.40E-04	2.70E+00	No				
Sulfuric Acid	7664939	24-hour	5.29E-02	2.40E+00	No	15-min	3.01E-01	3.00E+02	No

* Highest concentration over all averaging periods.

Environmental Protection Agency (EPA) Comments

The following are comments received from Environmental Protection Agency (EPA) on the OPC TA Smith modeling application and EPD's responses to these comments:

Comment 1 – Section 2.2.2 (Minimum Load Project Description)

Section 2.2.2 (Minimum Load Project Description) discusses the Minimum Load Project and indicates that "these upgrades would allow steady-state operations of the turbines at loads of approximately 49 MW, with some variations for ambient temperatures, while still achieving continuous compliance. The proposed Minimum Load Project would have no impact on the capacity of the turbines." We recommend that the modeling report include a discussion of the potential impact on air quality resulting from the minimum load project, specifically how the flow rates and temperatures would change at minimum loads.

EPD Response: EPD agrees, and OPC TA Smith has provided updated modeling on October 2019 considering this minimum load. This is addressed in the modeling memo.

Comment 2 – Section 3.2 (Ambient Background Data)

Section 3.2 (Ambient Background Data) lists the selected background monitors and concentrations.

- For the $PM_{2.5}$ Rossville monitor, the values listed in Table 3-2 do not match what is in AQS for this monitor. AQS indicates that the 2017 DV for that monitor is 18 µg/m^3 for 24hr $PM_{2.5}$ and 9.0 µg/m^3 for annual $PM_{2.5}$; whereas Table 3-2 lists the 24-hr $PM_{2.5}$ background as 16.8 µg/m^3 and the annual background as 8.4 µg/m^3. Please clarify the discrepancy. EPA recognizes that the modeled $PM_{2.5}$ impacts are below the SIL and that NAAQS modeling did not need to be performed for this permit application.
- EPA notes that the monitor used for NO_2 background is no longer in operation and stopped running at the end of 2015. The choice of the background monitor appears appropriate. We do recommend providing additional justification regarding the temporal representativeness of the data in light of the monitor being shut down in 2015.

EPD Response: The PM2.5 background is different due to using average vs worst case; in either case it does not alter the conclusion of the modeling review. The Rossville monitor data is still considered valid by EPD because the area is still representative of a rural area in Georgia, without substantial growth or loss of industrial sources within the immediate area.

Comment 3 – Section 4.3 (Receptor Grid Coordinate System)

Section 4.3 (Receptor Grid Coordinate System) indicates that "The assessment of the SIA utilized a 50 km receptor grid for PM_{10}, and $PM_{2.5}$ (NAAQS), and 10 km for $PM_{2.5}$ Increment. For annual NO_2, an approximately 15 km receptor grid was utilized. However, for the 1-hr NO_2 averaging period significance modeling, it was necessary to extend the receptor grid further to the west to encapsulate all receptors which were found to exceed the 1-hr NO_2 SIL." Additionally, footnote 45 on page 5-2 indicates that, "As can be seen in Appendix A, the significant receptors are not contiguous due to the complex terrain features in the area of the facility." EPA notes that the $PM_{2.5}$ (NAAQS) and PM_{10} modeling grids extend out to 50 km and capture the terrain to the east of the facility as seen in the figures in Appendix A. However, the NO_2 modeling does not capture the impacts at that terrain because the receptor grid only extends out to 15 km to the east. Figure A-

10 illustrates that significant 1-hour NO_2 concentrations above the SIL are predicted in high terrain areas to the west of the facility. Similar high terrain areas to the east of the facility are not captured by the receptor grid. The State should consider whether an additional receptor grid is needed to the east to capture some of the higher terrain in that area for NO_2 SIL modeling.

EPD Response: EPD agrees, and OPC TA Smith has provided updated modeling on October 2019 considering this additional receptor grid to the east.

Comment 4 – Section 4.5.1 (Representativeness of Emission Sources)

Section 4.5.1 (Representativeness of Emission Sources) indicates that "The diesel-fired backup generators and diesel-fired emergency fire pump at the facility are intermittent sources and, therefore, do no need to be included as an emission source in the modeling analysis." Please provide some quantification of emissions from these sources as it relates to the cumulative NAAQS analysis for 1-hour NO_2. Additional justification should demonstrate that these sources do not have emissions that could significantly impact the "annual distribution of daily 1-hr maximum values." The additional information should include the typical hours of operations and whether the emissions occur on a routine or non-routine basis, using the past 3 years as an estimate of NO_2 emissions, if available.

EPD Response: EPD and OPC TA Smith did not model emergency generators in accordance with precedent and EPD implementation of US EPA guidance on this topic – warning that modeling such sources may overpredict impacts. These generators are limited in use – running 1 hour every week or month for readiness testing, and the hours of testing are not set -therefore modeling may not reflect actual operations.

Comment 5 – Section 4.5.6.1. (Ozone MERPs Assessment) and Section 4.5.6.2 ($PM_{2.5}$ MERPs Assessment)

Section 4.5.6.1. (Ozone MERPs Assessment) and Section 4.5.6.2 ($PM_{2.5}$ MERPs Assessment) provides calculations for assessing ozone and secondary $PM_{2.5}$. Based on the Georgia EPD document "February 2019 Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia" dated February 25, 2019, (Georgia EPD guidance) MERPs were utilized as a Tier 1 demonstration tool for ozone and $PM_{2.5}$ since emission rates for those constituents are proposed to be above the applicable significant emission rates. The Georgia EPD Guidance is based on the December 2016 DRAFT EPA document "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program (EPA-454/R-16-006)". On April 30, 2019, the EPA updated and finalized this guidance (EPA-454/R-19-003). The EPA Region 4 recommends that the State evaluate new information in the April 2019 EPA guidance that might be relevant to Georgia and consider making revisions to the Georgia EPD MERPs Guidance if it is determined to be appropriate.

EPD Response: Current EPD MERPS guidance is conservative and sufficient, but EPD will consider making revisions to the Georgia EPD MERPs Guidance in future applications as appropriate.

Comment 6 – Section 5.2 (Class II and Class I Significance Analyses)

Section 5.2 (Class II and Class I Significance Analyses) states that "As shown in Table 5-2, all direct modeled $PM_{2.5}$ impacts, as well as PM_{10} modeled impacts, are less than the applicable Class II SILs. Further, as noted in the MERPs analysis in Section 4.5.6, the modeled impacts for annual and 24-hr $PM_{2.5}$ are also below the Class II SILs when conservatively considering both direct and secondary $PM_{2.5}$ modeled impacts (e.g. less than 98% of the annual SIL, and 94.65% of the 24-hr SIL). As such, by definition, the projects does not cause or contribute to an exceedance of the NAAQS or Class II Increment for $PM_{2.5}$ or PM_{10}." This section also states, "If conservatively accounting for the secondary $PM_{2.5}$ predicted highest impacts, as outlined previously in Section 4.5.6, in addition to the direct $PM_{2.5}$ modeled concentrations shown in Table 5-4, the total $PM_{2.5}$ impacts would still be below the Class I SILs for $PM_{2.5}$." EPA recommends that the secondary component of $PM_{2.5}$ be included in Table 5-2 and Table 5-4 for clarity.

EPD Response: EPD agrees, and OPC TA Smith has provided updated modeling on October 2019 including the secondary component of $PM_{2.5}$ be included in Table 5-2 and Table 5-4.

Comment 7 – Section 5.2 (Class II and Class I Significance Analyses)

Section 5.2 (Class II and Class I Significance Analyses), Table 5-4 has the Class I modeled results for $PM_{2.5}$ and PM_{10}. From looking at Table 5-4, it appears that the Class I $PM_{2.5}$ modeling was used as the basis for the Class I PM_{10} results. The emission rate used for the $PM_{2.5}$ increment SIL modeling is based on the difference between the future potential emission rate and the actual $PM_{2.5}$ emission rate on the $PM_{2.5}$ baseline date. Because the PM_{10} major source baseline date is different from the $PM_{2.5}$ major source baseline date, use of actual emissions on the $PM_{2.5}$ baseline date to calculate the PM_{10} increment SIL emission rate may be inappropriate. Therefore, in this case, the appropriate emission rate to use in the PM_{10} Class I SIL modeling is the difference between the future potential emissions and the past actual emission rate shown in Table D-4 of Appendix D.

EPD Response: EPD agrees, and OPC TA Smith has provided updated modeling on October 2019 using the appropriate emission rate in the PM_{10} Class I SIL modeling.

Comment 8 – Appendix D, Table D-6 and D-7

Appendix D, Table D-6 and D-7 lists the source parameters for the 1-hr NO_2 NAAQS modeling. When reviewing the modeling files, EPA noticed that Hour 4 was modeled at a different emission rate in the SUSD modeling than the emission rate indicated in Table D-7. Hour 4 was modeled at the non-SUSD emission rate of the CCCT1-4 units (a lower emission rate of 4.57 g/s) and not at the SUSD rate (15.12 g/s). Please provide additional information as to why the modeled emission rate doesn't match up with the emission rate in Table D-7.

EPD Response: This was a typo in the table, but the model was correct; OPC TA Smith has provided a corrected table in October 2019.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-213-0034-V-08-3.

Section 1.0: Facility Description

The facility will make control system changes to increase the capacity of Block 1 and Block 2 by approximately 28.6 MW per block in the summer, and 31.0 MW per block in the winter, referred to as the AGP Project III. The facility is also installing new turbine components and controls to allow sustained operations at lower operating loads, referred to as the Minimum Load Project. The AGP Project III is subject to PSD requirements.

Section 2.0: Requirements Pertaining to the Entire Facility

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

Section 3.0: Requirements for Emission Units

Table 3.1.1 was modified to include 40 CFR 60 Subpart KKKK applicability and remove 40 CFR 60 Subpart GG applicability for the combustion turbines. Subpart Da applicability was removed for the duct burners and 40 CFR 60 Subpart KKKK included.

Permit Condition 3.3.2a. is modified to exempt the 3.0 ppmvd limit for nitrogen oxides, during periods of startup and shutdown. Compliance will be demonstrated with the CEMS.

Permit Condition 3.3.2b is modified to clarify the averaging period; CEMS is used for the compliance demonstration

Permit Condition 3.3.2c. is modified to change the PM BACT limit from 25 lb/hr to 15 lb/hr.

Permit Condition 3.3.3 is modified to include the citation for 40 CFR Subpart KKKK.

Permit Condition 3.3.4 is modified to include the citation for 40 CFR Subpart KKKK.

Permit Condition 3.3.7 that contained the 73.6 megawatts (MWs) minimum operating limit except during periods of startup, and shutdown, or during periods of special testing, is deleted as the facility operates a CEMS to monitor for excess CO.

Permit Condition 3.3.12 is deleted that contained the applicability to 40 CFR 60 Subpart A as it is now included in new Condition 3.3.24.

Permit Condition 3.3.18 is deleted since the combustion turbines will not be subject to 40 CFR 60 Subpart GG, upon completion of the AGP Project III.

Permit Condition 3.3.21 is deleted that contained the requirement to submit minimum load testing results to the Division as the facility operates a CEMS to monitor for CO emissions.

Permit Condition 3.3.22 is added to include the GHG BACT limit of 1,270,090 tons during any twelve consecutive months combined from each of the stacks in Block 1 and Block 2.

Permit Conditions 3.3.23 is added to include the 40 CFR 60 Subpart KKKK nitrogen oxide emission standards.

Permit Condition 3.3.24 is added to include the general applicability requirements of 40 CFR 60 Subpart A – "General Provisions" and 40 CFR 60 Subpart KKKK – "Standards of Performance for Stationary Combustion Turbines," for operation of each of the combustion turbines and duct burners.

Section 4.0: Requirements for Testing

Permit Condition 4.1.3f. is modified to include Method 201A in conjunction with Method 202 in addition to Method 5 for particulate matter testing.

Permit Condition 4.1.3g is deleted as the test method is now subsumed by modified Condition 4.1.3f.

Permit Conditions 4.2.1, 4.2.2 and 4.2.3 are deleted as monitoring and special testing for minimum load is not required as the facility operates a CEMS to monitor for CO emissions.

Permit Condition 4.2.4 is added to include the specific testing requirements for filterable particulate matter and total PM_{10}/$PM_{2.5}$ to determine compliance with Condition 3.3.2c.

Permit Condition 4.2.5 is added to include the specific testing requirements for NOx emissions in accordance with 40 CFR Subpart KKKK.

Section 5.0: Requirements for Monitoring

Permit Condition 5.2.1 is modified to include the citation for 40 CFR 60 Subpart KKKK.

Permit Condition 5.2.3 is modified to include NOx emission rate calculations required by 40 CFR 60 Subpart KKKK and to remove atmospheric condition records required by 40 CFR 60 Subpart GG.

Section 6.0: Other Recordkeeping and Reporting Requirements

Permit Condition 6.1.7a.i is deleted since the turbines will no longer be subject to 40 CFR Subpart GG after completion of the AGP Project III.

Permit Condition 6.1.7a.ii is added to include the NOx emission standards per 40 CFR 60 Subpart KKKK.

Permit Condition 6.1.7b.i is modified to exclude periods of startup and shutdown.

Permit Condition 6.1.7b.v is modified to clarify the three-hour period for the CO emission rate.

Permit Conditions 6.1.7b.x. thru xiii. was added to include the exceedances for the total GHG emissions limit of 1,270,000 tons from each Block 1 and Block 2 as listed in Permit Condition 3.3.22.

Permit Condition 6.1.7c.i is modified to include the citation for 40 CFR 60 Subpart KKKK.

Permit Condition 6.1.7c. ii is deleted which included the excursion threshold for the lower operating load is removed as the facility operates a CEMs to monitor CO emissions.

Permit Condition 6.2.1 is modified to include the citation for 40 CFR 60 Subpart KKKK.

Permit Condition 6.2.3 is deleted as the combustion turbines are no longer subject to the nitrogen content for fuel in 40 CFR 60 Subpart GG.

Permit Condition 6.2.4 is modified to remove the citation to 40 CFR 60 Subpart GG.

Permit Condition 6.2.13e. is added to include the total GHG recordkeeping requirements for the rolling twelve-month total, from each stack specified in Condition. 3.3.1.

Permit Condition 6.2.15 is added and contains the monthly recordkeeping requirements to demonstrate compliance with the Condition 3.3.22 Total GHG limits for each stack specified in Condition 3.3.1.

Permit Condition 6.2.16 is added and contains the consecutive twelve-month recordkeeping requirements to demonstrate compliance with the Condition 3.3.22 Total GHG limits for each stack specified in Condition 3.3.1.

Permit Condition 6.2.17 is added to require notification of the initial startup after completion of the AGP Project III or the Minimum Load Project for each block.

Section 7.0: Other Specific Requirements

Permit Condition 7.14.1 is added to ensure the modification is constructed and operated as defined in Application No. 343540.

Permit Condition 7.14.2 is added to invalidate the project if construction is not commenced within 18 months or if the construction is not completed within a reasonable time.

Permit Conditions 7.15.1 through 7.15.3 are modified to update the current rule for the Cross-State Air Pollution Rule (CSAPR) Allowance Trading Program Requirements instead of the Clean Air Interstate Rule (CAIR) requirements which is no longer applicable.

APPENDIX A

Draft Revised Title V Operating Permit Amendment
OPC Thomas A. Smith Energy Facility
Dalton (Murray County), Georgia

APPENDIX B

Thomas A. Smith Energy Facility PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. TV-343540, dated May 7, 2019
2. Additional Information Packages Dated May 31, 2019, and June 18, 2019

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review

MEMORANDUM

December 16, 2019

To: James Eason and Renee Browne
Thru: Byeong-Uk Kim
From: Yunhee Kim
Subject: **PSD and Toxics Modeling Review**
Oglethorpe Power Corporation Thomas A. Smith Energy, Dalton, Murray County, GA

GENERAL INFORMATION

Oglethorpe Power Corporation Thomas A. Smith Energy Facility (hereafter, OPC Smith) proposed two modification projects for their combined cycle combustion turbines (CCCTs). These projects result in an increase in facility emissions. Air dispersion modeling for this application was conducted by OPC Smith's consultant, Trinity Consultants, to assess conformance of the proposed emission limits for the subject emission point sources on site with GA EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*[144] (hereafter "Georgia Air Toxics Guideline") and applicable federal Prevention of Significant Deterioration (PSD) air quality standards.

This memo discusses the procedures used to review the supporting dispersion modeling. Based on the PSD applicability analysis, the projected emissions of NO_2, $PM_{2.5}$, and PM_{10} are in excess of their respective Significant Emission Rates (SERs). The maximum-modeled concentrations of NO_2 and $PM_{2.5}$ were greater than their respective significant impact levels (SILs). Subsequent refined modeling analyses showed that NO_2 and $PM_{2.5}$ emissions from the modification projects are in compliance with the National Ambient Air Quality Standards (NAAQS) and the PSD Increment regulations. The maximum-modeled concentration of PM_{10} was less than its respective SIL; therefore, no further modeling was required for PM_{10}. The $PM_{2.5}$ impact analysis for primary emissions and secondary formation shows no adverse impacts from the proposed project NO_X and $PM_{2.5}$ emissions. The ozone ambient impact analysis and secondary ozone formation analysis show no adverse impacts from the proposed project NO_X emissions. The air toxic impacts from the thirteen Toxic Air Pollutants (TAPs) that were modeled do not exceed their applicable Acceptable Ambient Concentrations (AACs). The results of these modeling evaluations are summarized in the following sections of this memorandum.

INPUT DATA

1. **Meteorological Data** – The hourly meteorological data (2014-2018) used in this review were generated and provided by GA EPD[145]. The data were processed from the meteorological measurement data obtained from the Lovell Field Airport National Weather Service (NWS)

[144] https://epd.georgia.gov/air/documents/toxics-impact-assessment-guideline

[145] http://epd.georgia.gov/air/georgia-aermet-meteorological-data

surface station (TN) and the Atlanta Regional Airport NWS upper air station (GA) using AERSURFACE (v13016), AERMINUTE (v15272), and AERMET (v18081) with the adjusted surface friction velocity option (ADJ_U*). The applicant compared the AERSURFACE-generated surface characteristics around the facility's location to those at the Lovell Field Airport. The applicant found no significant differences. GA EPD concurred that these meteorological data are representative of the proposed facility site and can be used to evaluate the proposed criteria pollutant and air toxic emission rates for conformance with the federal PSD standards and the Georgia Air Toxics Guideline.

2. **Source Data** – Emission release parameters and emission rates of criteria pollutants and TAP emission rates were provided by the applicant and have been subjected to GA EPD engineering review. Tables D-1 to D-8 in Appendix D of the revised application dated October 2019 and Table 5-7 in the original application dated April 2019 summarized modeled point source parameters and the facility-wide TAP emissions from the proposed project. The projected emissions for $PM_{2.5}$ and PM_{10} in the proposed modeling were based on 18 lbs/hr in the revised application submitted on October 2019. Initially, the applicant submitted 100% and 75% load analyses. In addition, GA EPD requested that 50% load analysis be included as part of the updated modeling report.

3. **Receptor Locations** – Discrete receptors with 50-meter intervals were placed on a Cartesian grid along the fence line. For $PM_{2.5}$ and PM_{10} NAAQS analyses, receptors extend outwards from the fence line at 50-meter intervals to approximately 50 kilometers. For the $PM_{2.5}$ Increment analysis, receptors extend outwards from the fence line at 100-meter intervals to approximately 10 kilometers. For the annual NO_2 analysis, receptors extend outwards from the fence line at 100-meter intervals to approximately 15 kilometers. For the TAP analysis, receptors extend outwards from the fence line at 50-meter intervals to approximately 5 kilometers. These domains are sufficient to capture the maximum impact of each pollutant. All receptor locations are represented in the Universal Transverse Mercator (UTM) projections, Zone 16, North American Datum 1983.

4. **Terrain Elevation** – Topography was found to be generally flat in the site. Terrain data from USGS 1/3 arc-second National Elevation Dataset were extracted and the AERMAP terrain processor (v18081) was used to obtain the elevations of all sources and receptors. The resulting elevation data were verified by comparing contoured receptor elevations with a Google Earth map.

5. **Building Downwash** – The potential effect for building downwash was evaluated via the "Good Engineering Practice (GEP)" stack height analysis and based on the scaled site plan included in the application using the BPIPPRM program (v04274). The BPIPPRM model was used to derive building dimensions for the downwash assessment and the assessment of cavity-region concentrations appropriate for the AERMOD model.

CLASS I AREA IMPACT ANALYSIS

Seven Class I areas exist within a 300 km range from the OPC Smith facility: Cohutta Wilderness (GA), Joyce Kilmer-Slickrock Wilderness (TN), Great Smoky Mountains National Park (TN), Shining Rock Wilderness (NC), Sipsey Wilderness (AL), Mammoth Cave National Park (KY), and Linville Gorge Wilderness (NC).

To determine whether the proposed project is subject to the Class I modeling analysis, a Q/D screening analysis was performed. Q is the emission sum of all visibility-affecting pollutants (in tons per year) emitted from the facility and calculated on a worse-case 24-hour period basis (FLAG 2010 approach). D is the distance (in kilometers) from the proposed facility to each corresponding Class I area boundary. The emission sum of all visibility affecting pollutants (NO_X + PM_{10} + SO_2 + H_2SO_4) from the facility is 140.79 tpy. The distance from the facility to the nearest Class I area, Cohutta Wilderness (GA), is 30.6 km. The resulting Q/D ratio is 4.6. The Federal Land Managers (FLMs) typically do not require Air Quality Related Values (AQRVs) assessments in nearby Class I areas (those within 300 km of the project site) if the Q/D ratio is less than 10. The applicant provided the qualitative Q/D evaluation of its impact on nearby Class I areas to the applicable FLM agencies and requested their opinions on the findings of no adverse impacts to any AQRVs. No feedback was received.

A Class I area significant impact analysis (Class I PSD Increment analysis) was performed using AERMOD (v19191) to assess the maximum concentrations of NO_2, $PM_{2.5}$, and PM_{10} due to emissions from the facility without building downwash at a distance of 50 km from the project site. The receptors start and end at approximately 10 degrees on either side of the azimuth to the Class I areas of interest and were spaced about 1-km apart on a 50 km circle from the facility in the direction of the Class I areas. Since the Cohutta Wilderness Class I area is located within 50 km of the OPC Smith facility, the Class I area receptors were placed at 1-km apart throughout the Cohutta Wilderness area and directly evaluated in the AERMOD model. Table 1 shows that the modeled maximum primary impacts of NO_2, PM_{10}, and $PM_{2.5}$. NO_2 and PM_{10} were below their respective Class I area SILs; therefore, no further analysis was required for those pollutants. Primary $PM_{2.5}$ was below its respective Class I area SIL; however, additional analyses were conducted (described below) to account for the impact of secondary $PM_{2.5}$ formation due to SO_2 and NO_X emissions.

Table 1. Project Impacts And Significant Impact Levels (Class I Areas).

Criteria Pollutant	Averaging Period	Significance Level (µg/m^3)	Maximum Projected Concentration* (µg/m^3)	Receptor UTM Zone: 16 Easting (meter)	Receptor UTM Zone: 16 Northing (meter)	Exceeds SIL?
NO_2	Annual	0.1	0.081	715,010.77	3,868,445.20	No
PM_{10}	Annual	0.2	0.040	715,010.77	3,868,445.20	No
	24-Hour	0.3	0.262	715,010.77	3,868,445.20	No
$PM_{2.5}$	Annual	0.05	0.046	715,010.77	3,868,445.20	No
	24-Hour	0.27	0.135	715,010.77	3,868,445.20	No

* Highest concentration over all averaging period

As required by the 2017 revisions to EPA's *Guideline on Air Quality Models* (Appendix W), an analysis of the impact of the projected SO_2 and NO_X emissions on secondary $PM_{2.5}$ formation was required following EPA's "*Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier l Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program*" (December 2, 2016; hereafter EPA MERPs Guidance) and GA EPD's *"Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia*" (February 25, 2019; hereafter GA EPD MERPs Guidance).

The projected $PM_{2.5}$ increase is 153.32 tpy, which is greater than the SER (10 tpy). To estimate the impact of secondary $PM_{2.5}$ formation on Class I areas, a Class I SIL analysis for $PM_{2.5}$ is required. Table 1 shows that the modeled maximum primary impacts of $PM_{2.5}$ were below their respective Class I area SILs. According to Equation (3) in the GA EPD MERPs Guidance, the total impact of primary and secondary $PM_{2.5}$ due to the proposed emission increase with regard to the annual $PM_{2.5}$ SIL can be determined as following:

$$\frac{HMC\_PM2.5}{SIL\_PM2.5} + \frac{PEMIS\_SO2}{MERP\_SO2} + \frac{PEMIS\_NOx}{MERP\_NOx} = \frac{0.046}{0.05} + \frac{14.5}{6{,}004} + \frac{127.5}{7{,}427} = 0.92 + 0.0024 + 0.0172 = 0.94 < 1,$$

HMC_PM2.5 is 0.046 $\mu g/m^3$, which is the highest modeled annual concentration using AERMOD with the proposed primary (direct) $PM_{2.5}$ emission increase (see Table 1). *SIL_PM2.5* is 0.05 $\mu g/m^3$ for the annual $PM_{2.5}$. *PEMIS_SO2* and *PEMIS_NO*$_X$, the proposed emission increases for SO_2 and NO_X, are 14.5 tpy and 127.5 tpy, respectively. *MERP_SO2* and *MERP_NO*$_X$, the annual $PM_{2.5}$ MERPs for SO_2 and NO_X, are 6,004 tpy and 7,467 tpy, respectively.

Similarly, the total impact of primary and secondary $PM_{2.5}$ due to the proposed emission increase with regard to the 24-hour $PM_{2.5}$ SIL is estimated as following:

$$\frac{HMC\_PM2.5}{SIL\_PM2.5} + \frac{PEMIS\_SO2}{MERP\_SO2} + \frac{PEMIS\_NOx}{MERP\_NOx} = \frac{0.135}{0.27} + \frac{14.5}{667} + \frac{127.5}{4{,}014} = 0.50 + 0.022 + 0.032 = 0.55 < 1,$$

HMC_PM2.5 is 0.135 $\mu g/m^3$, which is the highest modeled 24-hr concentration using AERMOD with the proposed primary (direct) $PM_{2.5}$ emission increase (see Table 1). *SIL_PM2.5* is 0.27 $\mu g/m^3$ for the 24-hr $PM_{2.5}$ SIL. *MERP_SO2* and *MERP*_NO_X, the 24-hr $PM_{2.5}$ MERPs for SO_2 and NO_X, are 667 tpy and 4,014 tpy, respectively.

Because both ratios are less than 1, the total $PM_{2.5}$ impacts are below the $PM_{2.5}$ Class I SILs at the annual and 24-hr averaging periods. Therefore, the applicant does not need to perform a cumulative analysis for $PM_{2.5}$.

Class I Visibility Analysis

Visibility can be affected by plume impairment and/or regional haze. Plume impairment occurs when there is a contrast or color difference between the plume and a viewed background. Plume impairment is generally only of concern when the Class I area is near the proposed source (less than 50 km). Since the distance between the OPC Smith facility and the Cohutta Wilderness is 30.6 km, plume impairment was considered. The applicant utilized the VISCREEN model to estimate plume blight at the nearest Class I receptor location as well as at a distance of 50 km to ensure that plume impairment will remain at acceptable levels. A level 2 analysis was performed using the worst-case 1% meteorological conditions along with all other level 1 default values in VISCREEN. The worst-case 1% meteorological conditions were determined from the 5 years of representative meteorological data at the Lovell Field Airport NWS. The combination of stability class "C" and wind speed of 3 m/s yields the 1.03% cumulative frequency condition. Therefore, the evaluation of plume blight showed no issues with visibility based on impacts for the Cohutta Wilderness Class I area.

<u>CLASS II AREA IMPACT ANALYSIS</u>

The Class II area significant impact analysis was conducted using the AERMOD model (v19191) for NO_2, $PM_{2.5}$, and PM_{10}. Table 2 shows the maximum-modeled concentrations from the significance modeling. Significant impact levels were exceeded for 1-hour NO_2 and annual $PM_{2.5}$. The significant impact area (SIA) was determined for NO_2 and $PM_{2.5}$ as a circular area centered on the facility with a radius equal to the farthest distance where a receptor reached or exceeded the corresponding SIL. The radius of the SIA is referred to as the significant impact distance (SID). The SIDs were 8.7 km for 1-hour NO_2 and 0.6 km for annual $PM_{2.5}$. Further refined modeling analyses were required for 1-hour NO_2 and annual $PM_{2.5}$ to assess the compliance with their corresponding NAAQS and applicable PSD Increment regulations.

Table 2. Project Impacts and Significant Impact Levels (Class II Areas).

Criteria Pollutant	Averaging Period	Significant Impact Level	Maximum Projected Concentration*	Receptor UTM Zone: 16		Exceeds SIL?	Radius of the SIA
		($\mu g/m^3$)	($\mu g/m^3$)	Easting (meter)	Northing (meter)		(km)
NO_2	Annual	1	0.27	690,514.00	3,843,487.10	No	N/A
	1-Hour⁺	7.5	28.7	681,944.70	3,843,797.00	**Yes**	**8.7**
PM_{10}	Annual	1	0.22	690,514.00	3,843,487.10	No	N/A
	24-Hour	5	1.02	681,814.00	3,842,987.10	No	N/A
$PM_{2.5}$	Annual#	0.2	0.25	690,514.00	3,843,487.10	**Yes**	**0.6**
	24-Hour#	1.2	1.05	690,914.00	3,842,387.10	No	N/A

* Highest concentration over all averaging periods, except 1-hour NO2 and annual and 24-hour PM2.5
+ Highest of the average individual year's highest 1-hour concentration across all receptors over 5-years modeling
# Highest of the average individual year's highest annual and 24-hour concentration across all receptors over 5-year modeling
- If the maximum projected concentration exceeds the significant level for any averaging period, refined NAAQS/Increment analysis is required for that pollutant.
- Maximum Significant Impact Distances used to define pollutants-specific modeling areas indicated in bold font.

A Class II SIL analysis for $PM_{2.5}$ is required to estimate the total impact of primary and secondary $PM_{2.5}$ formation on Class II areas. Table 2 shows that the modeled maximum impacts of $PM_{2.5}$ were above their respective Class II area SILs. According to Equation (3) in the GA EPD MERPs Guidance, the total impact of primary and secondary $PM_{2.5}$ due to the proposed emission increase with regard to the annual $PM_{2.5}$ SIL can be determined as following:

$$\frac{HMC\_PM2.5}{SIL\_PM2.5} + \frac{PEMIS\_SO2}{MERP\_SO2} + \frac{PEMIS\_NOx}{MERP\_NOx} = \frac{0.25}{0.2} + \frac{14.5}{6{,}004} + \frac{127.5}{7{,}427} = 1.25 + 0.0024 + 0.0172 = 1.27 > 1,$$

HMC_PM2.5 is 0.25 $\mu g/m^3$, which is the highest modeled annual concentration using AERMOD with the proposed primary (direct) $PM_{2.5}$ emission increase (see Table 2). *SIL_PM2.5* is 0.2 $\mu g/m^3$ for the annual $PM_{2.5}$ SIL.

Similarly, the total impact of primary and secondary $PM_{2.5}$ due to the proposed emission increase with regard to the 24-hour $PM_{2.5}$ SIL is estimated as following:

$$\frac{HMC\_PM2.5}{SIL\_PM2.5} + \frac{PEMIS\_SO2}{MERP\_SO2} + \frac{PEMIS\_NOx}{MERP\_NOx} = \frac{1.05}{1.2} + \frac{14.5}{667} + \frac{127.5}{4{,}014} = 0.88 + 0.022 + 0.032 = 0.94 < 1,$$

HMC_PM2.5 is 1.05 $\mu g/m^3$, which is the highest modeled 24-hr concentration using AERMOD with the proposed primary (direct) $PM_{2.5}$ emission increase (see Table 2). *SIL_PM2.5* is 1.2 $\mu g/m^3$ for the 24-hr $PM_{2.5}$ SIL.

For 24-hour $PM_{2.5}$, the total $PM_{2.5}$ impact (primary and secondary $PM_{2.5}$) is below the $PM_{2.5}$ Class II SIL at the 24-hr averaging period. However, for annual $PM_{2.5}$, the total $PM_{2.5}$ impacts (primary and secondary $PM_{2.5}$) is above the $PM_{2.5}$ Class II SIL at the annual averaging period. Therefore, the applicant needs to perform a cumulative analysis for the annual $PM_{2.5}$.

Variable Load Analysis

The source parameters for the combined cycle units (CCCT1-CCCT4) when operating at 50%, 75%, and 100% loads were evaluated to determine the worst case modeled impacts for each applicable pollutant. The results of these analyses are shown in Table 3. Results for 24-hour $PM_{2.5}$ and PM_{10} indicate that 75% loads can have the highest impacts. However, use of 75% load for 24-hr PM_{10} assessment was not necessary as the PM_{10} SILs were not exceeded with use of both 100% and 75% load cases in the significant analysis. Based on the results, 100% load case was used for all significant analyses, except for the 24-hour $PM_{2.5}$. For the 24-hour $PM_{2.5}$ assessment, the 75% load case was utilized.

Table 3. Variable Load Analysis Results for Combined Cycle Units.

Criteria Pollutants	Averaging Period	100% load* ($\mu g/m^3$)	75% load* ($\mu g/m^3$)	50% load* ($\mu g/m^3$)	Is 100% load worst cases?
NO_2	1-Hour	60.98	50.53	41.45	Yes
	Annual	0.58	0.53	0.47	Yes
PM_{10}	24-Hour	3.87	**3.88**	3.35	**No**
	Annual	0.32	0.29	0.26	Yes
$PM_{2.5}$	24-Hour	2.33	**2.46**	2.27	**No**
	Annual	0.34	0.27	0.24	Yes

* Highest concentration over all averaging periods, except annual NO_2 and PM_{10}. Annual NO_2 and PM_{10} were based on individual annual modeling results.

Preconstruction Monitoring Evaluation

GA EPD compared the maximum-modeled concentrations with the Significant Monitoring Concentrations (SMCs) to determine whether the facility is required to conduct preconstruction monitoring. Table 4 shows that the maximum modeled concentrations of NO_2 and PM_{10} are below their respective SMCs which exempt those pollutants from preconstruction monitoring requirements.

Table 4. Project Pollutant Monitoring De Minimis Impacts.

Criteria Pollutant	Averaging Period	*Significant Monitoring* Concentration	Maximum Projected Concentration*	Receptor UTM Zone: <u>16</u>	Exceeds SMCs?

		($\mu g/m^3$)	($\mu g/m^3$)	Easting (meter)	Northing (meter)	
PM_{10}	24-Hour	10	1.02	681,814.00	3,842,987.10	No
NO_2	Annual	14	0.27	690,514.00	3,843,487.10	No

* Highest concentration over all averaging periods.

Ozone Impact Analysis

If the proposed project results in a net VOC or NO_X emission increase greater than 100 tpy, the PSD rule requires an evaluation to determine whether pre-construction monitoring is warranted for ground level ozone. The proposed project will result in a net NO_X emission increase of 127.5 tpy. There is one ozone monitor at Fort Mountain in Dalton, Murray County, GA (AQS ID 13-213-0003). This monitor is approximately 28 km northeast of the OPC Smith site. Given this proximity and regional nature of background ozone, the Fort Mountain monitor was determined to provide a representative ozone concentration in the vicinity of facility. The applicant examined the 3-year rolling average ozone concentration at this monitor. The latest design value (i.e., 3-year average of 4^{th} highest maximum daily 8-hour ozone concentrations during 2015-2017) is 65 ppb. This area is in attainment with the 2015 ozone NAAQS (70 ppb).

As required by the 2017 revisions to EPA's *Guideline on Air Quality Models* (Appendix W), an analysis of the impact of the projected NO_X emissions on secondary ozone formation was required following EPA MERPs Guidance and GA EPD MERPs Guidance. According to the GA EPD MERPs guidance, the most conservative (lowest) Class II area NO_X and VOC MERP values for ozone in Georgia are 156 tpy and 3,980 tpy, respectively. According to Equation (2) in the GA EPD MERPs Guidance, the impact from ozone formation due to precursor emissions is estimated as following:

$$\frac{PEMIS\_NOx}{MERP\_NOx} + \frac{PEMIS\_VOC}{MERP\_VOC} = \frac{127.5}{156} + \frac{36.02}{3{,}980} = 0.82 + 0.009 = 0.83 < 1$$

$PEMIS\_NO_X$ and *PEMIS_VOC*, the proposed emission increases for NO_X and VOC, are 127.5 tpy and 36.02 tpy, respectively. The total impact of 0.83 ppb is below the ozone SIL (1 ppb). Therefore, no further modeling analysis was required.

REGIONAL SOURCE INVENTORIES

The significance modeling above shows two criteria pollutants (NO_2 and $PM_{2.5}$) exceeded their applicable SILs with a SID of 8.7 km for 1-hour NO_2 and 0.6 km for annual $PM_{2.5}$. Therefore, refined modeling analysis is required to assess their compliance with the NAAQS standard and allowable PSD increment.

GA EPD developed an online PSD modeling inventory[146]. The applicant evaluated all major and minor sources within SIDs plus 50 km (total screening area) for possible inclusion in the refined NAAQS and PSD Increment analysis. The Minor Source Baseline Date (MinSBD) for NO_2 in Georgia (May 5, 1988) was also used to determine if a particular NO_X source had to be included

[146] https://psd.gaepd.org/inventory/

in the NO_2 Increment inventory. The trigger date for $PM_{2.5}$ increment is October 20, 2011. The 20D methodology was applied to screen out those facilities not large enough (in terms of emission rates) to be included in the modeling analysis except for those facilities located within SIA. All facilities within SIA were included regardless of the magnitude of the emissions. Regional sources located within 2 km of each other were clustered together and their total emissions were used to apply the 20D methodology. The Ambient Ratio Method 2 approach was applied to all NO_X emissions and a range of NO_X-to-NO_2 ratios, 0.5-0.9, was multiplied to the modeled NO_2 concentrations. Maximum modeled NO_2 results were calculated by subtracting modeled NO_2 concentrations without modification from modeled NO_2 concentrations with modification on a receptor-by-receptor basis. Tables D-9 to D-16 in the application presented the "20D" screening, stack parameters, and emission rates for all sources included in the cumulative modeling analysis.

NAAQS ANALYSIS

The 1-hour NO_2 and annual $PM_{2.5}$ NAAQS compliance demonstrations were conducted using the latest AERMOD version (v.19191) with the facility-wide NO_2 and $PM_{2.5}$ emission plus the ambient background concentrations. The modeled receptors were limited to those locations where the OPC Smith facility was shown to have a potentially significant impact (modeled concentration greater than the SIL). The 1-hour NO_2 background concentrations of 30.3 µg/m^3 was based on the rolling three-year average values of the annual 98th percentile values over 2013-2015. The annual $PM_{2.5}$ background concentration (three-year average design values for 2015-2017) was obtained from the Ridge Trail Rd monitor in Sequoya, Hamilton County, TN. The following operational scenarios for 1-hour NO_2 were considered in the modeling:

- 100% Load – Normal site operations at 100% load for the entire day
- 4 AM Startup – "Startup and Shutdown" for facility CCCT units starting at 4 AM, with normal operation for the remainder of the day
- 10 AM Startup – "Startup and Shutdown" for facility CCCT units starting at 10 AM, with normal operation for the remainder of the day

Table 5. 1-hour NO_2 CLASS II Area NAAQS Assessment.

Scenario	Averaging Period	Predicted Concentration *(µg/m^3)	Background Concentration (µg/m^3)	Total Impact (µg/m^3)	NAAQS (µg/m^3)	Receptor Location UTM Zone: 16	
						Easting (meter)	Northing (meter)
100 % Load	1-hour	80.2	30.3	110.5	188	682,344.70	3,850,296.70
4 AM Startup		115.4		145.7		682,244.70	3,850,096.70
10 AM Startup		80.2		110.5		682,344.70	3,8502,96.70

*1-hour impact calculated as the average 8th-highest daily maximum 1-hour concentration across all receptors over the five modeling years.

According to Equation (6) in the GA EPD MERPs Guidance, the impact from secondary $PM_{2.5}$ formation on annual $PM_{2.5}$ is estimated as following:

$Background_{PM2.5} + MDV_{PM2.5} + \left(\frac{FEMIS_{SO2}}{MERP_{SO2}} + \frac{FEMIS_{NOx}}{MERP_{NOx}}\right) * SIL_{PM2.5} \;\; = 8.4 + 0.93 + \left(\frac{251.2}{6{,}004} + \frac{691.3}{7{,}427}\right) * 0.2$

$$= 8.4 + 0.93 + 0.027 = 9.36 < 12,$$

$Background_{PM2.5}$ is 8.4 μg/m^3, which is the 3-year design value from a representative background $PM_{2.5}$ monitor. $MDV_{PM2.5}$ is 0.93 μg/m^3, which is the modeled design value concentration (not including background) using AERMOD with the proposed primary (direct) $PM_{2.5}$ emission increase and primary $PM_{2.5}$ emissions from nearby offsite sources (see Table 5). *FEMIS_SO2* and *FEMIS_NO*$_X$, the facility-wide emissions for SO_2 and NO_X, are 251.2 tpy and 691.3 tpy, respectively. $SIL_{PM2.5}$ is 0.2 μg/m^3 for annual $PM_{2.5}$ SIL.

Table 6. Annual $PM_{2.5}$ Class II Area NAAQS Assessment.

Predicted Concentration * (μg/m^3)	Secondary Contribution$^{(1)}$ (μg/m^3)	Background Concentration (μg/m^3)	Total Impact ** (μg/m^3)	NAAQS (μg/m^3)	Receptor Location UTM Zone: 16	
					Easting (meter)	Northing (meter)
0.93	0.004	8.4	9.33	12	690,514.00	3,843,487.10

* Highest concentration for annual averaging periods, and the highest of the average 1st-highest concentration across all receptors over the five modeling years for $PM_{2.5}$ annual.

** Total impact is the sum of the predicted concentration, secondary $PM_{2.5}$ (MERP), plus the background concentration.

(1) Secondary $PM_{2.5}$ concentration (MERP) estimated from the NO_X and SO_2 emissions at the proposed facility to account for secondary $PM_{2.5}$ formation.

Tables 5 and 6 illustrate sums of the predicted concentrations of NO_2 and total $PM_{2.5}$ (primary $PM_{2.5}$ plus secondary $PM_{2.5}$) and their corresponding background concentrations do not exceed the corresponding NAAQS levels for each operating scenario. Therefore, OPC Smith will not cause or contribute a significant impact to the NAAQS.

CLASS II PSD INCREMENT ANALYSIS

Similar to the NAAQS analysis, a modeling analysis was conducted using the AERMOD model with the same receptor grids and regional source inventories used in the NAAQS analysis. The modeling results presented in Table 7 demonstrate that the proposed facility will not exceed the allowable PSD increments.

Table 7. Annual $PM_{2.5}$ CLASS II Area PSD Increment Assessment

Predicted Concentration* (μg/m^3)	Secondary Contribution$^{(1)}$ (μg/m^3)	Maximum Increment Consumed ** (μg/m^3)	Allowable Increment (μg/m^3)	Receptor Location UTM Zone: 16	
				Easting (meter)	Northing (meter)
1.05	0.004	1.1	4	690,514.00	3,843,487.10

* Highest concentration for annual averaging periods.

** Maximum increment consumed is the sum of the predicted concentration and secondary $PM_{2.5}$ (MERP) concentration.

(1) Secondary $PM_{2.5}$ concentration (MERP) estimated from the NO_X and SO_2 emissions at the proposed facility to account for secondary $PM_{2.5}$ formation.

AIR TOXICS ASSESSMENT

The impacts of facility-wide TAP emissions were evaluated to demonstrate compliance according to the Georgia Air Toxics Guideline. Thirteen TAPs were included in the analysis: acetaldehyde, acrolein, ammonia, arsenic, barium, benzene, 1,3-butadiene, cadmium, chromium, formaldehyde, nickel, propylene oxide, and sulfuric acid. The annual, 24-hour, and 15-minute AACs of the thirteen TAPs were reviewed based on U.S. EPA IRIS reference concentration (RfC), OSHA Permissible Exposure (PEL), ACGIH Threshold Limit Values (TLV) including STEL (short term exposure limit) or ceiling limit, and NIOSH Recommended Levels (RELs) according to the Georgia Air Toxics Guideline. The modeled MGLCs were calculated using the AERMOD dispersion model (v18081) for annual, 24-hour, and 1-hour averaging periods.

Table 8 summarizes the AAC levels and MGLCs of the thirteen TAPs. The maximum 15-minute impact is based on the maximum 1-hour modeled impact multiplied by a factor of 1.32. As shown in Table 8, the modeled MGLCs for all thirteen TAPs are below their respective AAC levels.

Table 8. Modeled MGLCs and the respective AACs.

Pollutants	CAS	Averaging period	MGLC* ($\mu g/m^3$)	AAC ($\mu g/m^3$)	Exceed AAC?	Averaging period	MGLC* ($\mu g/m^3$)	AAC ($\mu g/m^3$)	Exceed AAC?
Acetaldehyde	75070	Annual	8.69E-03	4.55E+00	No	15-min	1.17E+00	4.50E+03	No
Acrolein	107028	Annual	2.10E-04	2.00E-02	No	15-min	1.45E-02	2.30E+01	No
Ammonia	7664417	Annual	3.45E-01	1.00E+02	No	15-min	2.42E+01	2.40E+03	No
Arsenic	7440382	Annual	1.00E-05	2.33E-04	No	15-min	1.85E-04	2.00E-01	No
Barium	7440393	24-hour	9.30E-04	1.19E+00	No				
Benzene	71432	Annual	4.20E-04	1.30E-01	No	15-min	2.89E-02	1.60E+03	No
1.3-Butadiene	106990	Annual	1.00E-05	3.00E-02	No	15-min	9.77E-04	1.10E+03	No
Cadmium	7440439	Annual	4.00E-05	5.56E-03	No	15-min	9.90E-04	3.00E+01	No
Chromium	7440473	Annual	5.00E-05	8.30E-05	No	15-min	1.27E-03	1.00E+01	No
Formaldehyde	50000	Annual	6.21E-03	7.70E-01	No	15-min	4.11E-01	2.45E+02	No
Nickel	7440020	24-hour	4.40E-04	7.94E-01	No				
Propylene Oxide	75569	Annual	9.40E-04	2.70E+00	No				
Sulfuric Acid	7664939	24-hour	5.29E-02	2.40E+00	No	15-min	3.01E-01	3.00E+02	No

* Highest concentration over all averaging periods.

ADDITIONAL IMPACTS ANALYSIS

To address the potential soil and vegetation impacts, the applicant adopted the NAAQS analysis presented above because EPA recently proposed to use the secondary NAAQS standards for such analysis. Note that annual and 24-hour PM_{10}, 24-hour $PM_{2.5}$, and annual NO_2 were not significant in comparison with their respective SILs. Table 9 shows the total potential impacts of 1-hour NO_2 and annual $PM_{2.5}$ are all below their respective secondary NAAQS. Therefore, no detrimental effects on soil or vegetation are expected from the proposed facility.

In addition, emissions from the proposed facility were compared to the significant emission rates according to the US EPA guidance document "*A Screening Procedure for the Impact of air*

Pollution Sources on the Plants, Soils, and Animals" (December 1980). Potential annual emissions from the proposed facility are all below the significant emission rates in the guidance.

Table 9. CLASS II AREA Vegetative Impact Results (AERMOD with downwash)

Pollutant	Averaging Period	All Source Impact * ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Potential Impact* ($\mu g/m^3$)	Secondary NAAQS ($\mu g/m^3$)	Exceed Secondary NAAQS Level?
NO_2	1-hour	115.4	30.3	145.7	188	No
$PM_{2.5}$	Annual	0.93	8.4	9.33	12	No

* NAAQS results including facility-wide emissions and offsite inventories. A total impact is a sum of the predicted concentration plus the background concentration.

Regarding the Class II visibility analysis, the modeled annual NO_2 and 24-hr PM_{10} concentrations did not exceeded their respective significant impact levels; therefore, it was not necessary to conduct an analysis of visible plume impacts.

CONCLUSIONS

The project's air quality analysis described in this memo show conformance with Class I and Class II PSD NAAQS and Increments. No Class I AQRV analysis was required by the FLMs. Class II area visibility analysis was not required. The proposed project will not cause or contribute to an exceedance of any NAAQS or any allowable increment. The air toxics analysis shows conformance with the Georgia Air Toxics Guideline. The additional impacts analysis indicates that air quality impacts on vegetation is expected to be minimal.

For these reasons, it is recommended a permit to be issued based on the project design and operating hours described in the application.