NORTH CAROLINA DIVISION OF AIR QUALITY

PRE-CONSTRUCTION REVIEW AND PRELIMINARY DETERMINATION

Issue Date:

Region: Winston-Salem Regional Office
County: Stokes
NC Facility ID: 8500004
Inspector's Name: Robert Barker
Date of Last Inspection: 09/13/2017
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Duke Energy Carolinas, LLC - Belews Creek Steam Station

Facility Address:
Duke Energy Carolinas, LLC - Belews Creek Steam Station
3195 Pine Hall Road
Walnut Cove, NC 27009

SIC: 4911 / Electric Services
NAICS: 221112 / Fossil Fuel Electric Power Generation

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 02D. 0503, 02D .0516, 02D .0521, 02Q .0504, 02D .0530(u), 02D .1111
NSPS: NA
NESHAP: 40 CFR Part 63, Subpart DDDDD
PSD: 02D .0530
PSD Avoidance: NA
NC Toxics: 02D .1100, 02Q .0711
112(r): NA
Other: NA

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Brenda Johnson Environmental Professional (336) 445-0634 3195 Pine Hall Road Belews Creek, NC 27009	Reginald Anderson General Manager III (336) 445-0501 3195 Pine Hall Road Belews Creek, NC 27009	Erin Wallace Sr. Environmental Specialist (919) 546-5797 410 South Wilmington Street Raleigh, NC 27601

Application Data

Application Number: 8500004.18A
Date Received: 06/08/2018
Application Type: Modification
Application Schedule: PSD

Existing Permit Data

Existing Permit Number: 01983/T33
Existing Permit Issue Date: 09/05/2018
Existing Permit Expiration Date: 01/31/2022

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2016	5066.60	6792.52	123.64	1036.49	1149.04	81.38	40.94 [Fluorides (sum of all fluoride]
2015	6780.39	7101.62	137.84	1151.24	1273.12	173.88	117.16 [Hydrogen chloride (hydrochlori]
2014	7044.98	6121.65	137.25	1142.59	1437.99	135.95	116.32 [Hydrogen chloride (hydrochlori]
2013	5080.05	5017.18	130.53	1086.46	1661.53	155.00	126.37 [Hydrogen chloride (hydrochlori]
2012	4080.92	4958.19	146.83	1221.64	1790.17	199.36	164.12 [Hydrogen chloride (hydrochlori]

Review Engineer: Ed Martin

Review Engineer's Signature: **Date:**

FOR PUBLIC NOTICE

Comments / Recommendations:

Issue 01983/T34
Permit Issue Date:
Permit Expiration Date:

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Chronology

March 27, 2018	DAQ notified the Federal Land Managers (FLMs) (Andres Stacy, Bill Jackson, Jill Webster and Melanie Pitrolo) of the proposed project. In an email from Melanie Pitrolo to Tom Anderson (AQAB supervisor), DAQ was informed that based on the potential emissions from the project, it is not anticipated that there will be any adverse impacts to air quality related values (AQRVs) at Forest Service Class I areas and therefore the FLM would not be requesting that an AQRV modeling analysis be included as part of the permit application.
May 23, 2018	A Zoning Consistency Determination form signed by Stokes County Planning and Inspections was received.
June 8, 2018	Application received.
June 8, 2018	An application "completeness" letter was sent to DEC stating the application was incomplete because technical portions of the application were not sealed by a North Carolina registered professional engineer.
June 21, 1018	The D5 form for technical portions of the application was received and was sealed by Cynthia C. Winston, PE, on June 20, 2018.
June 26, 2018	The application was deemed complete for PSD applicability as of June 8, 2018, in accordance with 15A NCAC 2D .0530(r).
August 15, 2018	DEC's toxics dispersion modeling analysis was approved by Alex Zarnowski, AQAB.
August 16, 2018	DEC's PSD modeling analysis was approved by Alex Zarnowski, AQAB.

February 6, 2019	DAQ emailed their draft BACT determinations to DEC.
February 12, 2019	DEC responded to DAQ's above draft BACT determinations with their comments.
February 18, 2019	Sent draft permit and review to Robert Barker (Winston-Salem Regional Office) and Samir Parekh (Stationary Source Compliance Branch) for review (see Section 11.0).
February 20, 2019	Sent draft permit and review to DEC for review.
February 21, 2019	DEC provided comments on draft permit (see Section 11.0).
March 4, 2019	Sent draft permit to public notice in the Winston-Salem Journal.

1.0 Purpose of Application

Duke Energy Carolinas (DEC) is proposing to add natural gas co-firing capability to Units 1 and 2 and to convert Auxiliary Boilers 1 and 2 from No. 2 fuel oil-fired (propane for start-up only) to natural gas firing, removing all oil firing capabilities for these units and auxiliary boilers. As part of the project, Piedmont Natural Gas (PNG) will also install four 8 million British thermal units per hour (mmBtu/hr) natural gas heaters on the new natural gas supply line. PNG also plans to conduct "pigging" of the new natural gas line once every 5 to 7 years for routine inspections. The actual fuel mix fired in Units 1 and 2 will be based on cost, availability, and demand. Projected actual emissions are based on a 12-month fuel heat input use for Units 1 and 2 (each unit) of 57% for burning coal and 43% for burning natural gas (as discussed in Section 4.0). The project does not affect the originally permitted heat input of the boilers. The proposed project will be a Prevention of Significant Deterioration (PSD) major modification to a major source for carbon monoxide (CO) and volatile organic compounds (VOCs).

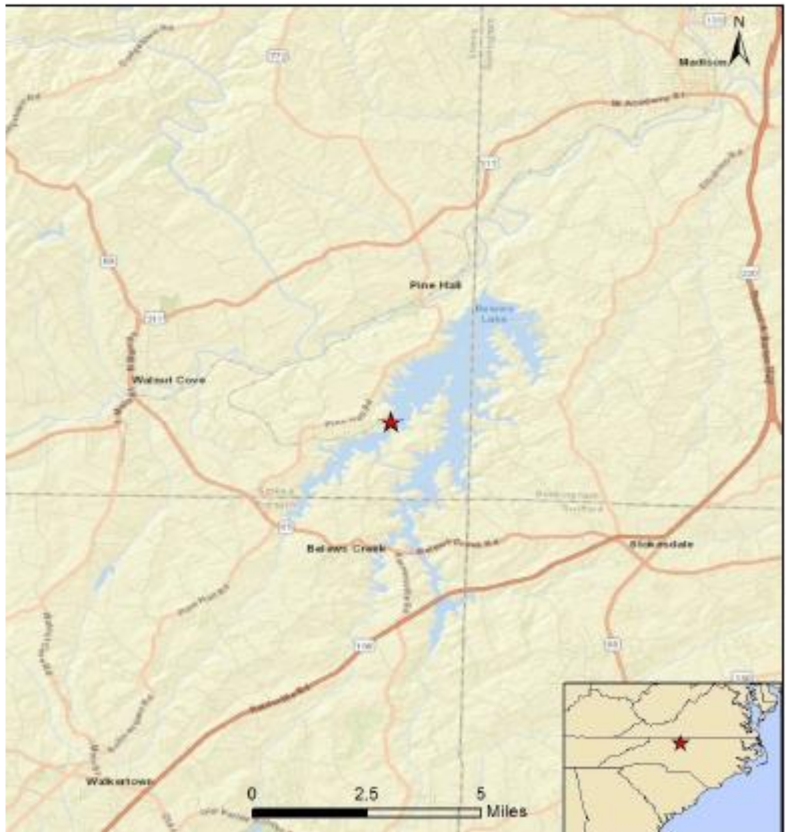
DEC's application has been reviewed by the North Carolina Division of Air Quality (DAQ), Permitting Section staff, to determine compliance with the requirements of all DAQ air pollution regulations and has made a preliminary determination, based on the information submitted, that it complies with all applicable North Carolina air quality regulations including the PSD requirements. Therefore, the attached draft air permit (Appendix A) for the modification described herein, with specific permit conditions and emission limits, is being submitted for public comment. The purpose of the public comment period is to develop a complete record, taking into account all available information, so that the DAQ can make a fully informed determination of whether this application in fact meets all legal and regulatory requirements.

DEC requested that the application be processed using the two-step process pursuant to rule 15A NCAC 02Q .0501(b)(2) and .0504, satisfying the permitting requirements in 02D .0530 (PSD) and 02Q .0300 (construction and operation permits). DEC will be required to submit an application for a Title V operating permit pursuant to 15A NCAC 02Q .0500 within 12 months of commencement of operation for these changes.

2.0 Area Description

2.1 Site Description

The Belews Creek Station is located in southeast Stokes County. The plant site is located approximately 31 kilometers (km) northeast of Winston-Salem, North Carolina. The approximate UTM coordinates are Zone 17, 584.394 km east and 4,015.569 km north at an elevation of approximately 800 feet above mean sea level. The largest city near the site is Winston-Salem, North Carolina. The Belews Creek Station is located in the Piedmont region of North Carolina and the terrain surrounding the site can be considered gently rolling. Figure 2-1 shows the site location.



DUKE ENERGY CAROLINAS, LLC BELEWS CREEK STEAM STATION WALNUT COVE, NC	AECOM 1600 Perimeter Park Drive, Suite 400 Morrisville, North Carolina 27560 Telephone 919-461-1100	SITE LOCATION	PROJECT NO. 60560209 FIG. NO. 2-1

2.2 Attainment Status of Area

Stokes County, where the Belews Creek Station is located, is classified as "better than national standards" for total suspended particulates (TSP, also referred to as Particulate Matter, PM, which includes particulate matter less than 10 microns, PM10) and for sulfur dioxide (SO2). Stokes County is designated as "unclassifiable/attainment" for carbon monoxide (CO), PM2.5, Lead, ozone, and 1-hour nitrogen dioxide (NO2), and is designated as "cannot be classified or better than national standards" for the annual NO_2 standard. The current Section 107 attainment status designations for areas within the state of North Carolina are summarized in 40 CFR 81.334.

3.0 Existing Facility Operations

DEC's Belews Creek Steam Station is an electric utility that generates electrical power using boilers. The Belews Creek facility has two coal/No. 2 fuel oil-fired electric utility boilers (ID Nos. ES-1 and ES-2, 12,000 million Btu per hour heat input each), two No. 2 fuel oil-fired auxiliary boilers (ID Nos. ES-3 and ES-4, 172 million Btu per hour heat input, each), one No. 2 fuel oil-fired emergency/blackout protection diesel generator (2000 kW), one No. 2 fuel oil-fired diesel emergency air compressor (525 hp), two emergency diesel IC engines, and various supporting scrubber limestone equipment.

4.0 Project Emissions

A. Emission Factors

To calculate emissions from the project, DEC used appropriate emission factors and throughputs. These sources include:

U.S. EPA AP-42 Emission Factors

Emission factors from U.S. EPA's AP-42 document (5th edition unless otherwise noted) were relied upon to calculate emissions from the project where test data, manufacturer guarantees, and EPRI factors were not available or representative. The following AP-42 sections were utilized to obtain emission factor data:

- Section 1.1, Bituminous and Subbituminous Coal Combustion;
- Section 1.3, Fuel Oil Combustion;
- Section 1.4, Natural Gas Combustion; and
- Section 13.5, Industrial Flares.

PM10 and PM2.5 Emission Factors for Natural Gas Combustion

The EPA's spreadsheet, *Emissions Factors for Particulate Matter from Natural Gas Combustion (xls)* found on their 2014 NEI documentation page (https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-documentation). The reference section states that the "EPA believes that the current AP-42 factors for condensable emissions are too high based on some limited data from a pilot-scale dilution sampling method that is similar to EPA's CTM 39." EPA's Roy Huntley developed corrected emission factors from preliminary test data gathered by Ron Myers (EPA) who was the lead on the development of a condensable PM test method at the time. The spreadsheet was last updated in 2012 and provides adjusted particulate matter emission factors for natural gas, process gas, and LPG combustion in boilers, engines, and heaters as listed. Rich Mason of the EPA confirmed with EPA emission factor experts that natural gas emission factors posted to the NEI/WebFIRE pages are valid replacements to the old AP-42 (and WebFIRE) emission factors.

The emissions calculations in the application utilize the condensable PM, PM10 filterable, and PM2.5 filterable emission factors for natural gas fired boilers that are referenced from the "Final table with Natural Gas Adjustment factors Nov 21 2006.xls." PM filterable is not addressed in this spreadsheet therefore the AP-42 Section 1.4 factor was retained. The ammonia emission factor was also utilized from this reference.

Electric Power Research Institute (EPRI) Data

EPRI is a nonprofit organization that conducts research on the power industry. EPRI's research is supported by electric utilities, government agencies, and corporations. DEC used emission factors from EPRI Report, *Guidelines for Estimating Trace Substance Emissions from Fossil-Fuel-Fired Steam Electric Power Plants, 2014 Technical Report* for certain specified sources.

Site Specific Data and Vendor Guarantees

Historical stack test and CEMS data were used to estimate emissions from existing sources where data was available and is preferred over published emission factors by EPRI or the EPA. NOx emissions were estimated using the maximum vendor emission guarantee in combination with the 80% SCR design control efficiency for Units 1 and 2. NOx emission guarantees were also used to estimate emissions from natural gas combustion in the auxiliary boilers and heaters with no control efficiency applied.

Regulatory and Permit Limits

The proposed VOC and CO BACT limits were used to estimate emissions increases from the addition of natural gas firing capability to Units 1 and 2, the auxiliary boilers, and the heaters. Potential emissions are estimated using permit limits, as applicable.

Greenhouse Gas Emission Factors

The U.S. EPA Mandatory Greenhouse Gas (GHG) reporting rule emission factors and global warming potentials from Subparts A and C were used to calculate emissions from carbon dioxide (CO_2), methane(CH_4), and nitrous oxide (N_2O) from combustion. Tables C-1 and C-2 to Subpart C of Part 98 list default CO_2, CH_4, and N_2O emission factors and high heat values for various fuel types. N_2O emissions from flaring natural gas during the pigging operation were calculated using 40 CFR Part 98, Subpart W, equation W-40.

B. Project Emissions

DEC performed a PSD applicability analysis to determine whether the project resulted in an emission increase of any regulated NSR pollutant above the applicable significance levels listed in 40 CFR 51.166(b)(23)(i). The PSD applicability analysis evaluated all applicable PSD-regulated air pollutants to be emitted, including NOx, PM (filterable), PM_{10}, $PM_{2.5}$, SO_2, VOCs, CO, HF, Pb, sulfuric acid (H_2SO_4), TRS, and carbon dioxide as CO_2e. The following describes the methodology used to determine the increases for the existing and new units:

PSD Applicability Test for Existing Units

For the existing units (Units 1 and 2, and Auxiliary Boilers 1 and 2), the *actual-to-projected actual test* was used in accordance with 40 CFR 51.166(a)(7)(iv)(c) to compare the difference between the *projected actual emissions* and the *baseline actual emissions* for each existing emissions unit as follows:

Projected Actual Emissions

In accordance with 40 CFR 40 51.166(b)(40)(i), *projected actual emissions* means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant, and full utilization of the unit would result in a significant emissions increase, or a significant net emissions increase at the major stationary source.

To determine the maximum annual rate, a source must consider all relevant information, including historical operational data, the company's expected business activity, and the company's highest projections of business activity for the five-year period after implementation of the project.

This project does not involve increasing the permitted heat input (design capacity) of the existing sources (Units 1 and 2 or its potential to emit. Post-project emissions for the addition of natural gas firing capability to Units 1 and 2 are based on the 5-year fuel use projection for Units 1 and 2 and the maximum projected total 12-month heat inputs for coal and gas during that period. The projected 12-month fuel heat input use (each unit) during this 5-year period is 38,950,845 mmBtu (57%) for burning coal and 29,740,090 mmBtu (43%) for burning natural gas. Projected actual emissions for Units 1 and 2 are based on a combination of coal and gas firing because the units will not be able to fire gas at their maximum capacity rating and the actual fuel mix will vary based on cost and availability. Projected actual emissions for the auxiliary boilers are based on historical heat input (no increase in utilization over the baseline is projected).

The projected actual emissions for the existing sources are shown in Table 1.

Table 1 – Projected Actual Emissions for Existing Sources, tons per year

Regulated NSR Pollutant	Projected Actual Emissions*						
	Unit 1		Unit 2		Aux Boiler 1	Aux Boiler 2	Total
	coal fired	gas fired	coal fired	gas fired	gas fired	gas fired	
NOx (as NO_2)	1,948	1,487	1,598	1,506	5.15	5.74	6,550
PM (filterable)	178	27.7	126	28.1	4.80E-02	5.35E-02	359.9
PM_{10}	509	7.58	404	7.68	1.31E-02	1.46E-02	928.3
$PM_{2.5}$	441	6.27	356	6.35	1.09E-02	1.21E-02	809.6
SO_2	3,830	8.75	2,983	8.86	1.52E-02	1.69E-02	6830.6
VOC	107	37.2	87.9	37.6	1.42E-01	1.58E-01	270.0
CO	1,558	1,190	1,278	1,205	2.06	2.30	5,235.4
HF	15.7	ND	12.9	ND	ND	ND	28.6
Lead	1.40E-02	7.29E-03	2.25E-02	7.38E-03	1.26E-05	1.41E-05	5.12E-02
Sulfuric Acid Mist	130	ND	45.6	ND	ND	ND	175
GHG as CO_{2e}	4,057,236	1,737,603	3,306,206	1,759,707	3,011	3,356	10,867,119

* From application Tables B-7 through B-10

<u>Baseline Actual Emissions</u>
In accordance with 15A NCAC 2D .0530(b)(1)(A), *baseline actual emissions* for an existing emissions unit are calculated as the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the five-year period immediately preceding the date that a complete permit application is received. However, the Director shall allow a different time period, not to exceed 10 years immediately preceding the date on which a complete permit application is received by the Division, if the owner or operator demonstrates that it is more representative of normal source operation. In accordance with 15A NCAC 2D .0530(b)(1)(a)(v), for a regulated NSR pollutant, if a project involves multiple emissions units, only one consecutive 24-month period shall be used to determine the baseline actual emissions for all the emissions units being changed. A different consecutive 24-month period for each regulated NSR pollutant may be used for each regulated NSR pollutant.

For this project, varying baseline periods were selected between 2013 and 2017 for the various pollutants (see Appendix B of the application). *Baseline actual emissions* represent the highest historical 24-month average annual emissions in tons per year for each pollutant.

The baseline emissions for the existing sources are shown in Table 2.

Table 2 - Baseline Actual Emissions for Existing Sources

Regulated NSR Pollutant	24 Month Baseline Period	Baseline Actual Emissions, tpy (average for 24 months)*				
		Unit 1	Unit 2	Aux Boiler 1	Aux Boiler 2	Total
NOx (as NO_2)	Jan 2015 – Dec 2016	3,567.5	3,374.5	5.65	6.85	6,954
PM (filterable)	Jan 3013 – Dec 2014	266.66	241.4	0.0945	0.1235	508
PM_{10}	Jan 3013 – Dec 2014	784.1	741.0	0.1285	0.1685	1,525
$PM_{2.5}$	Jan 3013 – Dec 2014	682.95	649.3	0.1105	0.145	1,333
SO_2	Nov 2013 - Oct 2015	3,583.5	3,332.0	0.0168	0.0232	6,915

Regulated NSR Pollutant	24 Month Baseline Period	Baseline Actual Emissions, tpy (average for 24 months)*				
		Unit 1	Unit 2	Aux Boiler 1	Aux Boiler 2	Total
VOC	Apr 2013 – Mar 2015	73.0	72.685	0.011	0.015	146
CO	Apr 2013 – Mar 2015	609.95	606.4	0.284	0.380	1217
HF	Apr 2013 – Mar 2015	24.34	24.18	0.00086	0.0012	48.5
Lead	Oct 2013 – Sep 2015	0.0211	0.04325	0.000052	0.0000715	0.0645
Sulfuric Acid Mist	Jan 2015 – Dec 2016	175.75	77.755	0.000297	0.0003575	253.5
GHG as CO_{2e}	Apr 2013 – Mar 2015	6,294,908.5	6,206,340	1,272.65	1,703.2	12,504,224

* From application Tables B-2 through B-5.

The total increase for the existing sources is the difference between the projected actual emissions from Table 1 and the baseline actual emissions from Table 2 as shown in Table 3.

Table 3 – Total Emissions Increase for Existing Sources, tons per year

Regulated NSR Pollutant	Projected Actual Emissions Minus Baseline Emissions		
	Projected Actual Emissions*	Baseline Actual Emissions*	Total Net Increase
NOx (as NO_2)	6,550	6,954	-404
PM (filterable)	359.9	508	-148.1
PM_{10}	928.3	1,525	-596.7
$PM_{2.5}$	809.6	1,333	-523.4
SO_2	6830.6	6,915	-84.4
VOC	270.0	146	124.0
CO	5,235.4	1,217	4,018.4
HF	28.6	48.5	-19.9
Lead	0.0512	0.0645	-0.0133
Sulfuric Acid Mist	175	253.5	-78.5
GHG as CO_{2e}	10,867,119	12,504,224	-1,637,105

* From Table 1
** From Table 2

PSD Applicability Test for New Units

For the new units (natural gas heaters ES-34a, ES-34b, ES-34c, ES-34d and natural gas line pigging operations ES-PIGGING), the *actual-to-potential test* was used in accordance with 40 CFR 51.166(a)(7)(iv)(d) to compare the difference between the *potential to emit* from each new emissions unit following completion of the project and the *baseline actual emissions* as follows:

Potential to Emit

In accordance with 15A NCAC 2D .0530(b)(4), *potential to emit* means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

Emissions were also calculated for the pigging of the natural gas line that is expected to occur following completion of construction and then once every 5 to 7 years. Emissions from pigging operations were based on engineering calculations using site-specific data and natural gas composition information. Pig receiver venting emissions were estimated assuming the entire internal volume of the receiver is vented to atmosphere each time a pig is received. NOx and CO emissions from flaring the natural gas supply during pigging operations were calculated using emission factors from AP-42, Table 13.5-1 and 13.5-2.

N_2O emissions from flaring were calculated using 40 CFR Part 98, Subpart W, equation W-40. VOC, methane, and organic HAP emissions were estimated using the supplier natural gas composition information and an assumed 98 percent destruction efficiency. SO_2 and CO_2 emissions from flaring were calculated using mass balance.

The potential emissions for the new sources are shown in Table 3.

Table 4 – Potential Emissions for New Sources, tons per year

Regulated NSR Pollutant	Potential Emissions, tpy*			
	Natural Gas Heaters	Pigging Fugitive	Flare	Total
	gas fired	gas released	gas burned	
NOx (as NO_2)	21.0	ND	2.12	23.12
PM (filterable)	2.61E-01	ND	ND	2.61E-01
PM_{10}	7.17E-02	ND	ND	7.17E-02
$PM_{2.5}$	5.91E-02	ND	ND	5.91E-02
SO_2	8.24E-02	ND	3.49E-01	4.314E-01
VOC	9.03	2.24E-01	4.56	13.814
CO	12.8	ND	9.68	22.48
HF	ND	ND	ND	ND
Lead	6.87E-05	ND	ND	6.87E-05
Sulfuric Acid Mist	ND	ND	ND	ND
GHG as CO_{2e}	16,378	28.3	4,493	20,899
TRS		3.38E-04	6.89E-03	7.23E-03

* From application Tables B-11 through B13.

Baseline Actual Emissions

In accordance with 15A NCAC 2D .0530(b)(1)(B), for a new emissions unit the *baseline actual emissions* shall equal zero and thereafter, for all other purposes, shall equal the unit's potential to emit.

The total net increase in emissions for the project is the increase for the existing sources from Table 3 plus the increase in potential emissions for the new sources from Table 4 as shown in Table 5. The total project emissions increases demonstrate that major New Source Review is required for VOCs and CO, while project increases for all other compounds are below the PSD significant emission rates. (Appendix B of the application contains the project emissions calculations).

Table 5 – Emissions Increases for Proposed Project, tons per year

Regulated NSR Pollutant	Increases for Existing Sources*	Increases for New Sources**	Emissions Increase/Decrease	Significant Emission Rate	Major Modification Review Required?
NOx (as NO_2)	-404	23.12	-381	40	No
PM (filterable)	-148.1	2.61E-01	-148	25	No
PM_{10}	-596.7	7.17E-02	-597	15	No
$PM_{2.5}$	-523.4	5.91E-02	-523	10	No
SO_2	-84.4	4.314E-01	-84	40	No
VOC	124.0	13.814	138	40	**Yes**
CO	4,018.4	22.48	4,041	100	**Yes**
HF	-19.9	ND	-19.9	3	No
Lead	-0.0133	6.87E-05	-0.0133	0.6	No
Sulfuric Acid Mist	-78.5	ND	-78.5	7	No
GHG as CO_{2e}	-1,637,105	20,899	-1,616,206	75,000	No
TRS		7.23E-03	7.23E-03	10	No

* From Table 3
** From Table 4

Table 6 – Projected Actual Emission Summary for the 02D .0530(u) Condition, tons per year

Regulated NSR Pollutant	Projected Actual Emissions			
	Unit 1	Unit 2	Aux Boiler 1	Aux Boiler 2
NOx (as NO_2)	3,435	3,104	5.15	5.74
PM (filterable)	205.7	154.1	4.80E-02	5.35E-02
PM_{10}	516.58	411.68	1.31E-02	1.46E-02
$PM_{2.5}$	447.27	362.35	1.09E-02	1.21E-02
SO_2	3,838.75	2,991.86	1.52E-02	1.69E-02
HF	15.7	12.9	ND	ND
Lead	0.0213	0.0299	1.26E-05	1.41E-05
Sulfuric Acid Mist	130	45.6	ND	ND
GHG as CO_{2e}	5,794,839	5,065,913	3,011	3,356

5.0 Regulatory Analysis

A. Existing sources
The following existing sources are affected by this modification:

1. **Two natural gas/coal-fired electric utility boilers equipped with alkaline-based fuel additive (ID Nos. ES-1 and ES-2), and associated flue gas conditioning systems (ID Nos. CD-1, CD-1A, CD-4, and CD-4A), low NOx burner systems (ID Nos. CD-2 and CD-5), SCR (ID Nos. CD-2A and CD-5A), hydrated lime dry sorbent injection (ID Nos. CD-U1DSI and CD-U2DSI, electrostatic precipitators (ID Nos. CD-3 and CD-6), and wet Flue Gas Desulfurization systems (ID Nos. CD (U1FGDa), CD (U1FGDb), CD (U2FGDa) and CD (U2FGDb))**

   The following regulations apply to these sources:

   a. Existing applicable regulations
   The following existing regulations are affected by this application:

15A NCAC 02D .0501(e): COMPLIANCE WITH EMISSION CONTROL STANDARDS
Emissions of sulfur dioxide from these sources shall not exceed 1.02 pounds per million Btu heat input.

No change to this regulation is required for co-firing natural gas with coal.

15A NCAC 02D .0519: CONTROL OF NITROGEN OXIDES EMISSIONS
Emissions of nitrogen oxides from these sources when burning coal and/or oil shall be calculated by the following equation:

$$E = [(Ec)(Qc) + (Eo)(Qo)]/Qt$$

Where: E = emission limit for combined burning of coal and gas in pounds per million Btu heat input
Ec = 1.8 pounds per million Btu heat input for coal only
Eo = 0.8 pounds per million Btu heat input for gas
Qc = coal heat input in Btu per hour
Qo = gas heat input in Btu per hour
Qt = Qc + Qo

No change to this regulation is required for co-firing natural gas with coal since the emission limit for gas, Eo, of 0.8 pounds per million Btu heat input is the same previously as for oil.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
This rule applies to all fuel burning sources and other processes that may have visible emissions. The permit condition for 15A NCAC 02D .0521 has two mutually exclusive options for monitoring visible emissions using either a continuous opacity monitor system (COMS) or a particulate matter continuous emissions monitor system (PM CEMS) as described below.

When using the COMS option, compliance with the 40 percent opacity limit shall be determined as follows:

i. No more than four six-minute periods shall exceed the opacity standard in any one day.
ii. The percent of excess emissions (defined as the percentage of monitored operating time in a calendar quarter above the opacity limit) shall not exceed 0.8 percent of the total operating hours. If a source operates less than 500 hours during a calendar quarter, the percent of excess emissions shall be calculated by including hours operated immediately previous to this quarter until 500 operational hours are obtained.
iii. Excess emissions during startup and shutdown shall be excluded from the determinations in sections i and ii above, if the excess emissions are exempted according to the procedures set out in 02D .0535(g). Excess emissions during malfunctions shall be excluded from the determinations in sections i and ii above above, if the excess emissions are exempted according to the procedures set out in 02D .0535(c).
iv. All periods of excess emissions shall be included in the determinations in sections i and ii above until such time that the excess emissions are exempted according to the procedures in 02D .0535.

When using the PM CEMS option**,** visible emissions shall not be more than 40 percent opacity when averaged over a six-minute period except that six-minute periods averaging not more than 90 percent opacity may occur not more than once in any hour nor more than four times in any 24-hour period.

No change to this regulation is required for co-firing natural gas with coal.

15A NCAC 02D .0536: PARTICULATE EMISSIONS FROM ELECTRIC UTILITY BOILERS
The permit condition for 15A NCAC 02D .0536 has two mutually exclusive options for monitoring, recordkeeping and reporting using either COMS or PM CEMS as described below.

Emissions of particulate matter from these sources shall not exceed 0.15 pounds per million Btu heat input.

A stack test is required to be conducted for particulate matter in accordance with either Method 5 or Method 5B of Appendix A of 40 CFR Part 60 once per calendar year.

When using the COMS option, compliance with the particulate limit shall be demonstrated through the Compliance Assurance Monitoring (CAM) Plan (see 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING (40 CFR Part 64) below).

When using the PM CEMS option, compliance with the particulate limit shall be demonstrated using a PM CEMS.

No change to this regulation is required for co-firing natural gas with coal.

State-Enforceable Requirement
15A NCAC 02D .0536: PARTICULATE EMISSIONS FROM ELECTRIC UTILITY BOILERS (Annual average opacity for electric utility boilers)
The permit condition for 15A NCAC 02D .0536 has two mutually exclusive options for monitoring, recordkeeping and reporting using either COMS or PM CEMS as described below.

Visible emissions from the utility boiler units shall not exceed 17 percent annual average opacity (AAO).

When using the COMS option, compliance is based on calculating an annual average opacity value each day for the most recent 365-day period ending with the end of the previous day.

When using the PM CEMS option, compliance is based on calculating an annual average opacity value each day for the most recent 365-day period ending with the end of the previous day. The hourly opacity values shall be determined using the PM CEMS hourly average output values as follows:

$$\text{Opacity, average for each hour} = \frac{(\text{Actual PM CEMS Output, average for each hour})(\text{Z, Opacity})}{(\text{Y, mg / m}^3)}$$

where:

Y = The average PM CEMS output value (mg/m^3) established during the initial PM CEMS PS-11 certification procedure at or near, but no greater than, the AAO limit. A concurrent Method 9 test shall be conducted during the PM CEMS measurements to determine opacity. At least 60 minutes of PM CEMS and Method 9 data shall be averaged.

Z = The average concurrent Method 9 opacity readings obtained during the initial PM CEMS PS-11 certification procedure corresponding to the PM CEMS measurements for Y above. The ratio of Z/Y has been determined from the initial CEMS certification testing to be 0.38 % opacity/mg/m^3 for Unit 1and 0.40 % opacity/mg/m^3 for Unit 2.

No change to this regulation is required for co-firing natural gas with coal.

15A NCAC 02D .0535: EXCESS EMISSIONS REPORTING AND MALFUNCTIONS
All electric utility boiler units shall have a malfunction abatement plan approved by the Director as specified in 15A NCAC 02D .0535(d).

No change to this regulation is required for co-firing natural gas with coal.

15A NCAC 02D .0606: SOURCES COVERED BY APPENDIX P OF 40 CFR PART 51 (SULFUR DIOXIDE MONITORING, CONTINUOUS OPACITY MONITORING, AND EXCESS EMISSIONS)
The permit condition for 15A NCAC 02D .0606 has two mutually exclusive options for monitoring opacity using either COMS or PM CEMS as described below.

Opacity Monitoring
When using the COMS option, continuous emissions monitoring and recordkeeping of opacity shall be performed as described in Paragraphs 2 and 3.1.1 through 3.1.5 of Appendix P of 40 CFR Part 51.

The quarterly excess emissions (EE) reports required under Appendix P of 40 CFR Part 51 shall be used as an indication of good operation and maintenance of the electrostatic precipitators. These sources shall be deemed to be properly operated and maintained if the percentage of time the opacity emissions, calculated on a 6-minute average, in excess of 40 percent (including startups, shutdowns, and malfunctions) does not exceed 3.0 percent of the total operating time for any given calendar quarter, adjusted for monitor downtime (MD) as calculated below. In addition, these sources shall be deemed to be properly operated and maintained if the %MD does not exceed 2.0 percent for any given calendar quarter as calculated below.

Calculations for %EE and %MD

Percent Excess Opacity Emission (%EE) Calculation:

$$\%EE = \frac{Total\ Excess\ Emission\ Time*}{Total\ Source\ Operating\ Time*** - Monitor\ Downtime}\ x100$$

Percent Monitor Downtime (%MD) Calculation for COMS:

$$\%MD = \frac{Total\ Monitor\ Downtime**}{Total\ Source\ Operating\ Time***}\ x\,100$$

Where:

* Total Excess Emission Time contains any 6-minute period greater than 40% opacity including startup, shutdown, and malfunction.

** Total Monitor Downtime includes Quality Assurance (QA) activities unless exempted by regulation or defined in an agency approved QA Manual. The amount of exempt QA Time will be reported in the quarterly report as such.

*** If a source operates less than 2200 hours during any quarter, the source may calculate the %EE and/or %MD using all operating data for the current quarter and the preceding quarters until 2200 hours of data are obtained.

When using the PM CEMS option, the alternative monitoring and recordkeeping procedure applies as allowed by Paragraph 3.9 of Appendix P of 40 CFR Part 51. The quarterly excess emissions (EE) reports shall be used as an indication of good operation and maintenance of the electrostatic precipitators. These sources shall be deemed to be properly operated and maintained if the percentage of time the PM emissions, calculated on a one-hour average, greater than 0.030 pounds per million Btu heat input* does not exceed 3.0 percent of the total operating time for any given calendar quarter, adjusted for monitor downtime (MD) as calculated in above, except that Total Excess Emission Time contains all one-hour periods greater than 0.030 pounds per million Btu heat input*. In addition, these sources shall be deemed to be properly operated and maintained if the %MD does not exceed 2 percent for any given calendar quarter as calculated above.

Sulfur Dioxide Monitoring
The Permittee shall use a CEMS to monitor and record sulfur dioxide emissions. Continuous emissions monitoring and recordkeeping of sulfur dioxide emissions shall be performed as described in Paragraphs 2 and 3.1.1 through 3.1.5 of Appendix P of 40 CFR Part 51. The monitoring systems shall meet the minimum specifications described in Paragraphs 3.3 through 3.8 of Appendix P of 40 CFR Part 51.

The quarterly excess emissions (EE) reports required under Appendix P of 40 CFR Part 51 shall be used as an indication of good operation and maintenance of the flue gas desulfurization scrubbers.

These sources shall be deemed to be properly operated and maintained if sulfur dioxide emissions do not exceed 1.02 pounds per million Btu calculated on a 24-hour basis.

No change to this regulation is required for co-firing natural gas with coal.

Federal-Enforceable Only

Cross State Air Pollution Rule (40 CFR Part 97, Subparts AAAAA, BBBBB, and CCCCC)

The Cross State Air Pollution Rule (CSAPR) replaced EPA's 2005 Clean Air Interstate Rule (CAIR), following the direction of a 2008 court decision that required EPA to issue a replacement regulation. CSAPR implementation began on January 1, 2015 to address sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) emissions from upwind states that crosses state lines and affects air quality in downwind states. The CSAPR requires fossil fuel-fired electric generating units at coal-, gas-, and oil-fired facilities in 27 states to reduce emissions to help downwind areas attain fine particle and/or ozone National Ambient Air Quality Standard (NAAQS).

These sources shall comply with all applicable requirements of 40 CFR Part 97, Subpart AAAAA "TR NOx Annual Trading Program", Subpart BBBBB "TR NOx Ozone Season Trading Program", and Subpart CCCCC "TR SO_2 Group 1 Trading Program".

No change to this regulation is required for co-firing natural gas with coal.

15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING (40 CFR Part 64)

The CAM rule applies to each emissions unit (source) at a Title V facility if the individual emissions unit uses an active control device to achieve compliance with an emission limit or standard, and if the potential pre-control emissions from that specific source are equal to or greater than the major source thresholds of any regulated pollutant. This regulation applies only during periods when the COMS compliance option is used. In order to assure the electrostatic precipitators are properly operated and maintained to control PM emissions in compliance with the 15A NCAC 02D .0536 PM limit of 0.15 pounds per million Btu heat input, these sources are subject to the following excursion points defined as an opacity value (based on a 3-hour block average) greater than:

ES-1 (Unit 1 Boiler) – 23 Percent
ES-2 (Unit 2 Boiler) – 28 Percent

Excluding periods of startup, shutdown, off-line activities, malfunction, and maintenance (e.g. soot blowing). Excursions trigger an inspection of the control system and corrective action. If five percent or greater of COMS data (averaged over a three hour block period and excluding startup, shutdown, off-line activities, malfunction, and maintenance) recorded in a calendar quarter show opacity values higher than those listed above, a stack test shall be performed in the following calendar quarter to demonstrate compliance with the 0.15 pounds per million Btu heat input particulate standard. If the stack test exceeds 80 percent of the PM limit, then retesting shall be conducted.

No change to this regulation is required for co-firing natural gas with coal.

15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (40 CFR PART 63, SUBPART UUUUU)

Subpart UUUUU MACT, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units" (MATS rule) applies to any coal-fired EGU or an oil-fired EGU as defined in §63.10042 of this subpart as specified in §63.9981.

These EGUs meet the definition of a coal-fired electric utility steam generating unit as defined in §63.10042 as:

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years.

The Belews Creek units are existing EGUs under the MATS rule since they did not commence construction or reconstruction after May 3, 2011 (§63.9982(d)). An existing EGUs must comply with the MATS rule no later than April 16, 2015 (§63.9984(b)).

There are two subcategories of EGUs per §63.9990 as defined in §63.10042:

i. EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and
ii. EGUs designed for low rank virgin coal.

The Belews Creek EGUs burn coal with a heating value greater than 8,300 Btu/lb. The requirements are different depending on which subcategory applies.

Belews Creek has chosen to comply with MATS by limiting emission as follows:

i. filterable particulate matter (PM) to 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh (using PM CEMS),
ii. sulfur dioxide (SO_2) to 2.0E-1 lb/MMBtu or 1.5E0 lb/MWh (using SO_2 CEMS), and
iii. mercury (Hg) to 1.2E0 lb/TBtu or 1.3E-2 lb/GWh (using Hg CEMS and/or sorbent trap(s)).

No change to this regulation is required for co-firing natural gas with coal. However, if these sources burn natural gas to the extent that coal is not burned for more than 10.0 percent of the average annual heat input during the 3 previous calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, they would not meet the definition of a *Coal-fired electric utility steam generating unit* and would therefore no longer be subject to Subpart UUUUU.

15A NCAC 02Q .0402 (40 CFR Part 72) PHASE II ACID RAIN PERMIT REQUIREMENTS

North Carolina air quality regulation 15A NCAC 2Q .0400 implements Phase II of the federal acid rain program pursuant to Title IV of the CAA as provided in 40 CFR Part 72 for sulfur dioxide and nitrogen oxides emissions from coal-fired utility unit. Issuance or denial of acid rain permits shall follow the procedures under 40 CFR Part 70 (Title V) and Part 72.

40 CFR Part 73 establishes the procedures for allocation, tracking, holding and transfer of sulfur dioxide emission allowances, including the initial allowances allocated to each applicable Phase II unit account to be held in calendar years 2000 through 2009 (per Table 2, column C) and in calendar years 2010 and each year thereafter (Table 2, column F).

40 CFR Part 76 establishes the NO_X emission limitations. DEC Energy has exercised the option to use NO_X emissions averaging to comply with the NO_X emissions limits. NO_X emissions averaging is a NO_X compliance option under 40 CFR 76.11 which allows any affected units subject to a NO_X emissions limit under 40 CFR 76.5, 76.6 or 76.7, under the control of the same owner and operator, and with the same designated representative, to average their NO_X emissions under an approved averaging plan.

No change to this regulation is required for co-firing natural gas with coal.

b. New applicable regulations

The following new regulations apply:

15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

Congress first established the New Source Review (NSR) program as part of the 1977 Clean Air Act Amendments and modified the program in the 1990 Amendments. The NSR program requires preconstruction review prior to obtaining a permit. The basic goal of NSR is to ensure that the air quality in clean (i.e. attainment) areas does not significantly deteriorate while maintaining a margin for future industrial growth. The NSR regulations focus on industrial facilities, both new and modified, that create large increases in the emission of certain pollutants. Prevention of Significant Deterioration (PSD) permits are a type of NSR permitting requirement for new major sources or sources making a major modification in an attainment area.

Pursuant to the Federal Register notice on February 23, 1982, North Carolina (NC) has full authority from the Environmental Protection Agency (EPA) to implement the PSD regulations in the State effective May 25, 1982. The DAQ's State Implementation Plan (SIP) - approved PSD regulations have been codified in 15A NCAC 02D .0530, which implement the requirements of 40 CFR 51.166. The Code of Federal Regulations (CFR) in 15A NCAC 2D .0530 are incorporated by reference unless a specific reference states otherwise.

Under PSD requirements all new major stationary sources and major modifications to major stationary sources are required by the Clean Air Act to obtain an air pollution permit prior to construction. This process of preconstruction review and approval by the permitting authority of the application for an air permit is called "new source review" (NSR). A "major stationary source" is defined as any one of 28 named source categories, listed in 40 CFR 51.166(b), which has the potential to emit 100 tons per year or more of any regulated pollutant, or any other stationary source which has the potential to emit 250 tons per year or more of any PSD regulated pollutant.

The Belews Creek Station is listed as one of the 28 PSD source categories (fossil-fueled steam electric plants greater than 250 mmBtu/hr heat input) and is a major stationary source for the purposes of PSD applicability. As such, the proposed project's emissions were evaluated to determine whether PSD permitting is required.

For existing major stationary sources, there are several steps to determine whether the modification is a *major modification* and therefore subject to PSD preconstruction review. The first step is to determine whether there is a physical change or change in the method of operation. Second, there must be an emissions increase. And third, the emissions increase must be equal to or greater than certain *significance levels* as listed in 40 CFR 51.166(b)(23)(i) for the regulated pollutants.

The change to add natural gas co-firing capability and remove oil-firing on Units 1 and 2 and the auxiliary boilers, and the addition of the new natural gas heaters is both a physical change and a change in the method of operation.

The project emissions increases/decreases presented in Table 5 show that emission increases for CO and VOCs are greater than the *significance levels*.

Because the proposed facility is a major stationary source, each pollutant with a *potential to emit* greater than the *significance levels* is subject to PSD review and must meet certain review requirements. *Potential to emit* is the maximum capacity of a stationary source to emit a pollutant under its physical and operational design, including any physical or operational limitation on the capacity of the source to emit a pollutant, provided the limitation or the effect on emissions is practically enforceable.

Therefore, the proposed project will be a PSD major modification to a major source for CO and VOCs, and PSD permitting is required for these compounds.

Facilities classified as major for PSD and applying for a significant modification are subject to all the requirements as defined in 40 CFR 51.166. These requirements include:

- a BACT determination, including an evaluation of unregulated pollutants such as toxic air pollutants,

- an Air Quality Impact Analysis including monitoring and air modeling to determine extent and significance of any potential air quality impact, and

- an Additional Impacts Analysis including effects on soils, vegetation, and visibility.

DEC performed these requirements related to PSD for CO and VOCs emissions.

The following new PSD requirements are being added to the permit for co-firing natural gas with coal:

Emission Limits

The following Best Available Control Technology (BACT) limits shall not be exceeded:

POLLUTANT	BACT EMISSION LIMIT	CONTROL TECHNOLOGY
CO	0.08 lb/million Btu (6-hour average), all operations except startups and shutdowns	Good combustion practices
	Work practice standards during start-ups and shut-downs See Section 2.1.A.12.b.i. through iii	Work practice standards
VOCs	0.0055 lb/million Btu (6-hour average), all operations except start-ups and shut-downs	Good combustion practices
	Work practice standards during start-ups and shut-downs See Section 2.1.A.12.b.i. through iii	Work Practice Standards

i. For startup of a unit, the Permittee shall use clean fuels as defined in paragraph iii below for ignition. When firing coal, the Permittee shall utilize all of the applicable control technologies except dry scrubber and SCR. The Permittee shall start dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation.
ii. While firing coal during shutdown, the Permittee shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. If, in addition to the fuel used prior to initiation of shutdown, another fuel shall be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in paragraph iii below and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.
iii. Clean fuel means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) oil, including those fuels meeting the requirements of 40 CFR part 80, subpart I ("Subpart I-Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel").

Testing

Under the provisions of North Carolina General Statute 143-215.108, the Permittee shall demonstrate compliance with the BACT emission limits for Units 1 and 2 when burning (i) natural gas only and (ii) natural gas and coal co-firing, by conducting annual performance tests at greater than 90% of maximum rated heat input, utilizing EPA reference methods, as in effect on the date of permit issuance, contained in 40 CFR 60, Appendix A, AND in accordance with a testing protocol (using testing protocol submittal form) approved by the Division of Air Quality, as follows:

POLLUTANT	TEST METHOD
Carbon Monoxide	Method 10
Volatile Organic Compounds	Method 25A or Method 18

Use of any other test method for compliance purposes shall be approved in advance by the Division of Air Quality and must be based on a test protocol that documents the alternate method is at least as accurate as the reference method test listed above.

i. Test results shall be the average of 3 valid test runs.

ii. Within 60 days after achieving the maximum production rate at which the facility will be operated, but not later than 180 days after the commencement of natural gas burning in Units 1 and 2, the Permittee shall conduct the initial performance test(s) and submit a written report of the test(s) to the Regional Supervisor, Division of Air Quality. The Permittee shall conduct the subsequent annual performance tests (no more than 12 calendar months following the previous performance test) and submit the written reports to the Regional Supervisor, Division of Air Quality, within 60 days of completion of such annual performance tests.
iii. This permit may be revoked, with proper notice to the Permittee, or enforcement procedures initiated, if the results of the test(s) indicate that the facility does not meet applicable limitations.

Monitoring/Recordkeeping/Reporting
The Permittee shall perform periodic tune-ups on Units 1 and 2 in accordance with the following MACT Subpart UUUUU requirements:

The Permittee shall conduct periodic performance tune-ups of the EGUs, as specified in paragraphs (e)(1) through (9) of §63.10021. For the first tune-up, the Permittee may perform the burner inspection any time prior to the tune-up or delay the first burner inspection until the next scheduled EGU outage provided the requirements of §63.10005 are met. Subsequently, the Permittee shall perform an inspection of the burner at least once every 36 calendar months unless the EGU employs neural network combustion optimization during normal operations in which case an inspection of the burner and combustion controls shall be performed at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the tune-up work practice requirements shall be performed within 30 days after the re-start of the affected unit. The Permittee shall comply with the associated Subpart UUUUU recordkeeping and reporting.

15A NCAC 2D .0530(u): USE OF PROJECTED ACTUAL EMISSIONS TO AVOID APPLICABILITY OF PREVENTION OF SIGNIFICANT DETERIORATION REQUIREMENTS
Under 15A NCAC 2D .0530(u), for projects at existing emissions units at a major stationary source, the owner or operator may elect to use projected actual emissions to avoid applicability of prevention of significant deterioration requirements. DEC has provided projected actual emissions as shown in Table 1 for the existing sources. For those pollutants for which the increase has been demonstrated to not exceed the PSD significance level as shown in Table 5, the owner or operator shall maintain records of annual emissions in tons per year, on a calendar year basis related to the modifications, for 10 years following resumption of regular operations after the change if the project involves increasing the emissions unit's design capacity or its potential to emit the regulated NSR pollutant; otherwise, these records shall be maintained for five years following resumption of regular operations after the change. The owner or operator shall submit a report to the Director within 60 days after the end of each year during which these records must be generated. The project does not involve increasing the emissions unit's design capacity or its potential to emit; therefore, records of annual emissions shall be maintained for five years. DECs post-project emissions for the addition of natural gas firing capability to Units 1 and 2 are based on the 5-year fuel use projection for Units 1 and 2 and the maximum projected 12-month heat input during that period, assuming natural gas is available year-round. Units 1 and 2 projected actual emissions are based on a combination of coal and gas firing. The projected actual emissions shown in Table 6 are placed in the 02D .0530(u) condition for Units 1 and 2.

15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT
See Section 5.D.2 below.

2. Two natural gas-fired auxiliary boilers (ID Nos. ES-3 and ES-4)

The following regulations apply to these sources:

a. Existing applicable regulations
The following existing regulations are affected or potentially affected by burning of natural gas instead of fuel oil for this modification:

15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT

EXCHANGERS

Emissions of particulate matter from the combustion of natural gas that are discharged from these sources (ID Nos. ES-3 and ES-4) into the atmosphere shall not exceed 0.079 pounds per million Btu heat input.

The 0.079 pound per million Btu heat input limit remains the same to the nearest two significant figures as follows:

This rule applies to installations burning fuel, including natural gas and fuel oils, for the purpose of producing heat or power by indirect heat transfer. The affected sources, as shown below, to which this regulation applies are the three new combustion turbines (duct burner only), the new natural gas-fired auxiliary boiler, the new natural gas-fired fuel gas heater, and the three new natural gas-fired dew point heaters. For the purpose of this rule, the maximum heat input shall be the total heat content of all fuels which are burned in a fuel burning indirect heat exchanger, of which the combustion products are emitted through a stack or stacks. The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site which are in operation, under construction, or permitted shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter for each fuel burning indirect heat exchanger. Fuel burning indirect heat exchangers constructed or permitted after February 1, 1983, shall not change the allowable emission limit of any fuel burning indirect heat exchanger whose allowable emission limit has previously been set. The removal of a fuel burning indirect heat exchanger shall not change the allowable emission limit of any fuel burning indirect heat exchanger whose allowable emission limit has previously been established. However, for any fuel burning indirect heat exchanger constructed after, or in conjunction with, the removal of another fuel burning indirect heat exchanger at the plant site, the maximum heat input of the removed fuel burning indirect heat exchanger shall no longer be considered in the determination of the allowable emission limit of any fuel burning indirect heat exchanger constructed after or in conjunction with the removal. The emission rate for these sources is determined below.

The facility-wide heat inputs will be as follows:

Source	Heat Input (mmBtu/hr)
Boiler ES-1 (existing)	12,000
Boiler ES-2 (existing)	12,000
Auxiliary boiler ES-3 (AuxB1) (existing)	172
Auxiliary boiler ES-4 (AuxB2) (existing)	172
ES-34a natural gas supply line heater (new)	8
ES-34b natural gas supply line heater (new)	8
ES-34c natural gas supply line heater (new)	8
ES-34d natural gas supply line heater (new)	8
Total	24,376

Allowable emissions of particulate matter from fuel combustion shall be calculated as follows:

$$E = 1.090\ Q^{-0.2594}$$

where: E = allowable particulate emission rate, pounds per million Btu
Q = maximum heat input rate (total at plant site), million Btu per hour

Therefore, emissions of particulate matter from the combustion turbines shall not exceed the following:

$$\begin{aligned} E &= 1.090\ Q^{-0.2594} \\ &= 1.090\ (24{,}376)^{-.2594} \\ &= \mathbf{0.079\ lb/mmBtu} \end{aligned}$$

Compliance

Since these boilers will only fire natural gas, emissions of particulate matter will be much less than the above limit and therefore no monitoring/recordkeeping/reporting is required for emissions of particulate matter from this source to assure compliance with this regulation.

15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
Emissions of sulfur dioxide from these sources shall not exceed 2.3 pounds per million Btu heat input. No monitoring, recordkeeping, or reporting is required for sulfur dioxide emissions.

No change is required for burning natural gas.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
For sources manufactured as of July 1, 1971, visible emissions shall not be more than 40 percent opacity (except during startup, shutdowns, and malfunctions) when averaged over a six-minute period except that six-minute periods averaging not more than 90 percent opacity may occur not more than once in any hour nor more than four times in any 24-hour period.

Compliance
Monitoring, recordkeeping and reporting of visible emissions was removed since visible emissions for burning natural gas are insignificant.

15A NCAC 02D .1109: 112(j) CASE-BY-CASE MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
These boilers are subject to this §112(j) standard until May 19, 2019. The initial compliance date for the applicable Subpart DDDDD MACT standard for "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters" is May 20, 2019 (see below).

No change is required for burning natural gas.

15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
(40 CFR PART 63, SUBPART DDDDD)
Replacing the burning of fuel oil/propane with burning of natural gas results in the boilers being subject to the Subpart DDDDD *Unit designed to burn gas 1 subcategory*. DEC has requested the limited-use boiler provisions in the previous permit (Permit No. 01983T33) be removed. However, DEC will be allowed to operate these boilers under those limited-use boiler provisions in the previous permit until startup of the boilers on natural gas.

These boilers are subject to the 112(j) Case-By-Case MACT requirements until May 19, 2019, and become subject to the Subpart DDDDD MACT requirements on May 20, 2019. The following table shows the changes being made to change from the limited-use boiler provisions to the *Unit designed to burn gas 1 subcategory* provisions.

Permit Section	Subpart DDDDD Section	Subpart DDDDD Requirement
New Permit Sections Changed or Added		
2.1.B.5.a	§63.7575 §63.7499(l)	*Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas.
2.1.B.5.d 2.1.B.5.k (added)	§63.7510(e)	For existing affected sources you must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date.
2.1.B.5.i	§63.7515(d)	If you are required to meet an applicable tune-up work practice standard, you must conduct an annual tune-up according to §63.7540(a)(10). Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up.
2.1.B.5.h	§63.7540(a)(10)	If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or

		process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up.
2.1.B.5.n 2.1.B.5.l	§63.7550(b)	For units that are subject only to a requirement to conduct subsequent annual tune-up according to §63.7540(a)(10) and not subject to emission limits or Table 4 operating limits, you may submit only an annual compliance report as specified in paragraphs (b)(1) through (4) of this section instead of a semi-annual compliance report.
Permit Section Removed		
2.1.B.5.b	§63.7575	Limited-use provisions no longer apply.

b. New applicable regulations
The following new regulations apply:

15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See regulatory discussion in Section 5.A.1.b above.

The following new PSD requirements are being added to the permit for co-firing natural gas with coal:

Emission Limits
The following Best Available Control Technology (BACT) limits shall not be exceeded:

POLLUTANT	BACT EMISSION LIMIT	CONTROL TECHNOLOGY
CO	0.08 lb/million Btu (6-hour average), all operations except startups and shutdowns	Good combustion practices and the use of pipeline quality natural gas
VOCs	0.0055 lb/million Btu (6-hour average), all operations except start-ups and shut-downs	

Testing
Under the provisions of North Carolina General Statute 143-215.108, the Permittee shall demonstrate compliance with the BACT emission limits for the auxiliary boilers by conducting an initial one time performance test at the maximum achievable heat input, utilizing EPA reference methods, as in effect on the date of permit issuance, contained in 40 CFR 60, Appendix A, AND in accordance with a testing protocol (using testing protocol submittal form) approved by the Division of Air Quality, as follows:

POLLUTANT	TEST METHOD
Carbon Monoxide	Method 10
Volatile Organic Compounds	Method 25A or Method 18

Use of any other test method for compliance purposes shall be approved in advance by the Division of Air Quality and must be based on a test protocol that documents the alternate method is at least as accurate as the reference method test listed above.

i. Test results shall be the average of 3 valid test runs.
ii. Within 60 days after achieving the maximum production rate at which the facility will be operated, but not later than 180 days after the commencement of natural gas burning in the auxiliary boilers, the Permittee shall conduct the initial performance test(s) and submit a written report of the test(s) to the Regional Supervisor, Division of Air Quality.

iii. This permit may be revoked, with proper notice to the Permittee, or enforcement procedures initiated, if the results of the test(s) indicate that the facility does not meet applicable limitations.

Monitoring/Recordkeeping/Reporting
The Permittee shall perform periodic tune-ups on the auxiliary boilers (ID Nos. ES-3 and ES-4) in accordance with the MACT Subpart DDDDD requirements in Section 2.1.B.5.h through j of the permit and comply with the associated Subpart DDDDD recordkeeping and reporting.

15A NCAC 2D .0530(u): USE OF PROJECTED ACTUAL EMISSIONS TO AVOID APPLICABILITY OF PREVENTION OF SIGNIFICANT DETERIORATION REQUIREMENTS
Under 15A NCAC 2D .0530(u), for projects at existing emissions units at a major stationary source, the owner or operator may elect to use projected actual emissions to avoid applicability of prevention of significant deterioration requirements. DEC has provided projected actual emissions as shown in Table 1 for the existing sources. For those pollutants for which the increase has been demonstrated to not exceed the PSD significance level as shown in Table 5, the owner or operator shall maintain records of annual emissions in tons per year, on a calendar year basis related to the modifications, for 10 years following resumption of regular operations after the change if the project involves increasing the emissions unit's design capacity or its potential to emit the regulated NSR pollutant; otherwise, these records shall be maintained for five years following resumption of regular operations after the change. The owner or operator shall submit a report to the Director within 60 days after the end of each year during which these records must be generated. The project does not involve increasing the emissions unit's design capacity or its potential to emit; therefore, records of annual emissions shall be maintained for five years. DECs post-project emissions for the addition of natural gas firing capability to Units 1 and 2 are based on the 5-year fuel use projection for Units 1 and 2 and the maximum projected 12-month heat input during that period, assuming natural gas is available year-round. Post-project emissions for the substitution of natural gas firing capability from fuel oil firing are based on the 5-year fuel use projection for Auxiliary Boiler 1 and 2 and the maximum projected total 12-month heat input during that period, assuming natural gas is available year-round. Auxiliary Boilers 1 and 2 projected actual emissions are based on 100% gas firing. The projected actual emissions shown in Table 6 are placed in the 02D .0530(u) condition for auxiliary boilers 1 and 2.

15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT
See Section 5.C.2 below.

B. New Sources
The following new sources are being added:

1. Four natural gas-fired, natural gas supply line heater (ID Nos. ES-34a, ES-34b, ES-34c and ES-34d)

The following regulations apply to these sources:

15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
Emissions of particulate matter from the combustion of natural gas that are discharged from these sources (ID Nos. ES-34a, ES-34b, ES-34c and ES-34d) into the atmosphere shall not exceed 0.079 pounds per million Btu heat input.

This limit remains the same to the nearest two significant figures (see Section 5.B.1 above).

Compliance
No monitoring, recordkeeping, or reporting is required for emissions of particulate matter from the firing of natural gas in these sources.

15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
Emissions of sulfur dioxide from these sources shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

Compliance
No monitoring, recordkeeping, or reporting is required for sulfur dioxide emissions from the firing of natural gas in these sources.

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
Visible emissions from these sources shall not be more than 20 percent opacity (except during startups, shutdowns, and malfunctions) when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Compliance
No monitoring/recordkeeping/reporting is required for visible emissions from the firing of natural gas in these sources.

15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY
(40 CFR PART 63, SUBPART DDDDD)
As specified in Subpart DDDDD §63.7485, this subpart applies to owners or operators of industrial, commercial, or institutional boilers or process heaters as defined in §63.7575 that is located at, or is part of, a major source of HAP (as defined in §63.2), except as specified in §63.7491. This subpart applies to new, reconstructed, and existing affected sources as follows:

> The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in §63.7575.
>
> The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in §63.7575, located at a major source.

A boiler or process heater is new if construction is commenced after June 4, 2010. A boiler or process heater is existing if it is not new or reconstructed.

These heaters will burn natural gas and therefore are classified as Units designed to burn gas 1 fuels as listed in §63.7499(l).

The following Subpart DDDDD sections apply:

Permit Section	**Subpart DDDDD Section**	**Subpart DDDDD Requirement**
2.1.K.4.a.i	§63.7495(a)	If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.
2.1.K.4.h 2.1.K.4.k 2.1.K.4.l	§63.7540(a)	You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.
2.1.K.4.h	§63.7540(a)(11)	If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.
2.1.K.4.h	§63.7500(e)	Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission

		limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.
2.1.K.4.i	§63.7510(g)	For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable biennial schedule as specified in §63.7515(d) following the initial compliance date. Thereafter, you are required to complete the applicable biennial tune-up as specified in §63.7515(d).
2.1.K.4.j	§63.7515(d)	If you are required to meet an applicable tune-up work practice standard, you must conduct a biennial tune-up according to §63.7540(a)(11). Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed affected source, the first biennial tune-up must be no later than 25 months after the initial startup of the new affected source.
2.1.K.4.n	§63.7550(b)	For units that are subject only to a requirement to conduct subsequent biennial tune-up according to §63.7540(a)(11), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only a biennial compliance report as specified in paragraphs (b)(1) through (4) of this section according to the dates the permitting authority has established instead of a semi-annual compliance report.

<u>15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION</u>
See regulatory discussion in Section 5.A.1.b above.

The following new PSD requirements are being added to the permit for co-firing natural gas with coal:

<u>Emission Limits</u>
The following Best Available Control Technology (BACT) limits shall not be exceeded:

POLLUTANT	BACT EMISSION LIMIT	CONTROL TECHNOLOGY
CO	0.0914 lb/million Btu (6-hour average), all operations except startups and shutdowns	Good combustion practices and the use of pipeline quality natural gas
VOCs	0.0644 lb/million Btu (6-hour average), all operations except start-ups and shut-downs	

<u>Monitoring/Recordkeeping/Reporting</u>
The Permittee shall perform periodic tune-ups on the natural gas supply line heaters (ID Nos. ES-34a, ES-34b, ES-34c and ES-34d) in accordance with the MACT Subpart DDDDD requirements in Section 2.1.B.5.h through j of the permit and comply with the associated Subpart DDDDD recordkeeping and reporting.

<u>15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT</u>
See Section 5.D.2 below.

2. Natural gas supply line pigging operation including fugitive emissions from pig receiver vent (ID No. ES-PIGGING) with associated temporary flare of natural gas from supply line (ID No. CD-PIG FLARE)

The following regulations apply to this source:

15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
Emissions of sulfur dioxide from these sources shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

Compliance
No monitoring/recordkeeping/reporting is required for sulfur dioxide emissions from the firing of natural gas in this source

15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS
Visible emissions from these sources shall not be more than 20 percent opacity (except during startups, shutdowns, and malfunctions) when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Compliance
No monitoring/recordkeeping/reporting is required for visible emissions from the firing of natural gas from this source.

15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION
See regulatory discussion in Section 5.A.1.b above.

The following Best Available Control Technology (BACT) limits shall not be exceeded:

POLLUTANT	BACT EMISSION LIMIT	CONTROL TECHNOLOGY
CO	work practices	flare
VOCs	work practices	

Monitoring/Recordkeeping
CO and VOC emissions from the natural gas supply line pigging operation (ID No. ES-PIGGING) shall be controlled as follows:

The flare (ID No. CD-PIG FLARE) shall be adequately sized and designed for combustion of the natural gas to be vented. Prior to each scheduled day for pigging, the flare will be inspected and maintained in accordance with the manufacturer's recommendations and a record of this activity maintained. A copy of the recommended inspection and maintenance procedure will be maintained on-site and any deviations from standard protocols due to site-specific considerations will be documented and maintained. The work practice standard for the receiver will be to keep access openings to the receiver closed at all times except when a pig is being placed into or removed from the receiver, or during active maintenance operations.

State-Only Requirement
15A NCAC 02D .1100 CONTROL OF TOXIC AIR POLLUTANTS
See Section 5.D.1 below.

15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT
See Section 5.D.2 below.

C. Multiple Emission Sources

Applicable Regulations

1. Facility-wide Toxics Demonstration

State-Only Requirement
15A NCAC 02D .1100 CONTROL OF TOXIC AIR POLLUTANTS
As a result of this modification to add natural gas co-firing, a facility-wide toxics modeling analysis is triggered for the toxic pollutants emitted by these sources.

In accordance with 15A NCAC 02Q .0709(a), the owner or operator of a source who is applying for a permit or permit modification to emit toxic air pollutants shall:

i. demonstrate to the satisfaction of the Director through dispersion modeling that the emissions of toxic air pollutants from the facility will not cause any acceptable ambient level listed in 15A NCAC 02D .1104 to be exceeded beyond the premises (adjacent property boundary); or
ii. demonstrate to the satisfaction of the Commission or its delegate that the ambient concentration beyond the premises (adjacent property boundary) for the subject toxic air pollutant shall not adversely affect human health (e.g., a risk assessment specific to the facility) though the concentration is higher than the acceptable ambient level in 15A NCAC 02D .1104.

As required by NCAC 02Q .0706(b), the owner or operator of the facility shall submit a permit application to comply with 15A NCAC 02D .1100 if the modification results in:

i. a net increase in emissions or ambient concentration of any toxic air pollutant that the facility was emitting before the modification; or
ii. emissions of any toxic air pollutant that the facility was not emitting before the modification if such emissions exceed the levels contained in 15A NCAC 02Q .0711.

As required by NCAC 02Q .0706(c), the permit application shall include an evaluation for all toxic air pollutants covered under 15A NCAC 02D .1104 for which there is:

i. a net increase in emissions of any toxic air pollutant that the facility was emitting before the modification; and
ii. emission of any toxic air pollutant that the facility was not emitting before the modification if such emissions exceed the levels contained in 15A NCAC 02Q .0711.
   All sources at the facility, excluding sources exempt from evaluation in 15A NCAC 02Q .0702, emitting these toxic air pollutants shall be included in the evaluation.

Duke performed a facility-wide air toxics analysis, for all sources in the permit, including the four new natural gas heaters and a flare and vent for the natural gas line pigging operations. The highest potential to emit emissions rates for Unit 1 and Unit 2 over all of the operating scenarios were used in the modeling analysis. PTEs were also calculated and modeled for all other facility sources that emit any of the natural gas combustion pollutants that exceed the toxic pollutant emission rates (TPERs).

AERMOD (18081), using five years (2012-2016) of meteorological data from Winston-Salem (surface) and Greensboro (upper air) was used to evaluate impacts in both simple and elevated terrain. Direction specific building dimensions, determined using EPA's GEP-BPIP Prime program (95086), were used as input to the model for building wake effect determination. Receptors were placed along the property boundary at 50 m intervals. Extending to 500 m from the property boundary receptors were placed at 50 m intervals. Receptors from 500 m to 10 km increased grid spacing to 100, 250, and 500 m.

Air toxics emissions for the sources in this permit subject to a Part 63 MACT (e.g., the existing electric generating Units 1 and 2 subject to the utility MACT Subpart UUUUU, the existing engines subject to MACT Subpart ZZZZ, and the existing auxiliary boilers 1 and 2 and the four new gas heaters all subject to the boiler MACT Subpart DDDDD) are exempt from air permitting, pursuant to 02Q .0702(a)(27)(B). Nevertheless, the Permittee has included emissions for all such exempt sources in the modeling analysis.

The first step of the modeling analysis was to perform a facility-wide TPER analysis using potential emissions to determine if the TPERs in rule 02Q .0711 are exceeded for any toxic emitted.

The results of the TPER analysis indicates which toxic pollutants exceed their respective TPERs as shown in Table 7.

Next, potential emissions were modeled for comparison to the respective Acceptable Ambient Levels (AALs) for the following pollutants:

- Ammonia (7664-41-7) – Hourly TPER exceeded
- Arsenic and Inorganic Arsenic Compounds (ASC) – Annual TPER exceeded
- Benzene (71-43-2) – Annual TPER exceeded
- Beryllium (7440-41-7) – Annual TPER exceeded
- Cadmium (7440-43-9) – Annual TPER exceeded
- Ethyl Mercaptan (75-08-1) – Hourly TPER exceeded
- Formaldehyde (50-00-0) – Hourly TPER exceeded
- N-Hexane (110-54-3) – Daily TPER exceeded
- Manganese (MNC) – Daily TPER exceeded
- Mercury Vapor (7439-97-6) – Daily TPER exceeded
- Nickel (7440-02-0) – Daily TPER exceeded
- Soluble Chromate (VI) Compounds (SOLCR6) – Daily TPER exceeded

Table 8 shows the resulting modeled impacts for the baseline analysis. All pollutants are well below 100% of their respective AALs. Then, based on the resulting concentrations from the potential model run, the emission rates were then increased to an optimized rate such that modeled allowable emission rates result in ambient concentrations that are 98% of the AAL. Results for the optimized analysis are shown in Table 9 below. Optimizing the emission rates provides the Belews Creek Plant with additional operational flexibility and should reduce the need for future TAP modeling analyses for these sources at the facility.

Table 7 - Toxic Pollutant Emission Rate (TPER) Analysis

Compound	Toxic Pollutant Emission Rates (TPER)				Belews Creek Steam Station Natural Gas Co-firing Modification							
	Acute Irritants	Acute Systemic Toxicants	Chronic Toxicants	Carcinogens	Acute Irritants		Acute Systemic Toxicants		Chronic Toxicants		Carcinogens	
	lb/hr	lb/hr	lb/day	lb/yr	lb/hr	Exceed TPER?	lb/hr	Exceed TPER?	lb/day	Exceed TPER?	lb/yr	Exceed TPER?
ARSENIC AND INORGANIC ARSENIC COMPOUNDS				0.053							202	**Yes**
BERYLLIUM				0.28							14.3	**Yes**
CADMIUM				0.37							230	**Yes**
MANGANESE AND COMPOUNDS			0.63						1.08	**Yes**		
MERCURY, VAPOR			0.013						0.152	**Yes**		
NICKEL METAL			0.13						1.37	**Yes**		
SOLUBLE CHROMATE COMPOUNDS, AS CHROMIUM (VI) EQUIVALENT			0.013						0.119	**Yes**		
AMMONIA	0.68				11.71	**Yes**						
BENZENE				8.10							456	**Yes**
BENZO(A)PYRENE				2.20							0.387	no
ETHYL MERCAPTAN		0.025					1.22	**Yes**				
P-DICHLOROBENZENE	16.8				0.0287	no						
FORMALDEHYDE	0.04				1.81	**Yes**						
N-HEXANE			23.0						3202	**Yes**		
TOLUENE	14.4		98.0		0.0939	no			2.25	no		

Table 8 – Summary of Baseline Modeling Analysis

Compound	Year	Averaging Period	Maximum Concentration ($\mu g/m^3$)	AAL ($\mu g/m^3$)	Percent of AAL (%)
Ammonia	2012	1-hour	1.81	2700	0.067
Arsenic	2012	Annual	0.0000595	0.0021	2.835
Benzene	2012	Annual	0.00280	0.12	2.333
Beryllium	2012	Annual	0.0000157	0.0041	0.382
Cadmium	2014	Annual	0.0000328	0.0055	0.596
Chromium VI	2015	24-hour	0.000100	0.62	0.016
Ethylene Mercaptan	2013	1-hour	11.79	100.00	11.793
Formaldehyde	2013	1-hour	1.34	150.00	0.890
n-Hexane	2012	1-hour	49.00	1100.00	4.455
Manganese	2015	24 hour	0.00310	31	0.010
Mercury	2012	24 hour	0.000208	0.6	0.035
Nickel	2015	24 hour	0.000979	6	0.016

Table 9 – Summary of Optimized Modeling Analysis

Compound	Year	Averaging Period	Maximum Concentration ($\mu g/m^3$)	AAL ($\mu g/m^3$)	Percent of AAL (%)
Ammonia	2012	1-hour	2638.72	2700	98
Arsenic	2012	Annual	0.00206	0.0021	98
Benzene	2012	Annual	0.118	0.12	98
Beryllium	2012	Annual	0.00402	0.0041	98
Cadmium	2014	Annual	0.00539	0.0055	98
Chromium VI	2015	24-hour	0.61	0.62	98
Ethylene Mercaptan	2013	1-hour	97.63	100.00	98
Formaldehyde	2013	1-hour	146.77	150.00	98
n-Hexane	2012	1-hour	1076.48	1100.00	98
Manganese	2015	24 hour	30.34	31	98
Mercury	2012	24 hour	0.59	0.6	98
Nickel	2015	24 hour	5.88	6	98

Duke’s toxics dispersion modeling analysis was approved by Alex Zarnowski, AQAB, (see memo to Ed Martin dated August 15, 2018) demonstrating compliance.

No toxics monitoring is required since the potential emissions are significantly below the optimized emissions which demonstrates compliance with the AALs as shown in Tables 8 and 9.

Detailed toxic emission calculations are presented in Duke’s application Appendix B.

The permit toxic limits for all sources modeled, except for the MACT sources, which are exempt from toxics permitting, are shown below in Table 10 and in permit condition 2.2.D.1.a.

Table 10
Permit Toxic Emission Limits

Emission Source	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
ES-6 (RUL), ES-6a (RULa), ES-6b (RULb), ES-7 (LUBF) Common exhaust through bagfilter CD (RULBf) Model ID DUSTRAIN	Arsenic and inorganic arsenic compounds	2.70E-01	-	-
	Beryllium	2.15E-01	-	-
	Cadmium	2.66E-01	-	-
	Manganese and compounds	-	1.20E+01	-
	Mercury Vapor	-	3.68E-04	-
	Nickel Metal	-	3.12E-01	-
ES-8 (LCB1) Model ID LIMEDROP (8 drop points)	Arsenic and inorganic arsenic compounds	1.03E-01	-	-
	Beryllium	8.20E-02	-	-
	Cadmium	1.02E-01	-	-
	Manganese and compounds	-	4.58E+00	-
	Mercury Vapor	-	1.40E-04	-
	Nickel Metal	-	1.19E-01	-
ES-10 (LCB2) Model ID LIMEDROP (8 drop points)	Arsenic and inorganic arsenic compounds	1.03E-01	-	-
	Beryllium	8.20E-02	-	-
	Cadmium	1.02E-01	-	-
	Manganese and compounds	-	4.58E+00	-
	Mercury Vapor	-	1.40E-04	-
	Nickel Metal	-	1.19E-01	-
F1 Limestone Stockpile, IES-74 Model ID LIMESTON	Arsenic and inorganic arsenic compounds	9.51E-01	-	-
	Beryllium	7.56E-01	-	-
	Cadmium	9.37E-01	-	-
	Manganese and compounds	-	4.22E+01	-
	Mercury Vapor	-	1.29E-03	-
	Nickel Metal	-	1.10E+00	-
ES-11a (LRGF) Model ID LIMEDROP (8 drop points)	Arsenic and inorganic arsenic compounds	1.03E-01	-	-
	Beryllium	8.20E-02	-	-
	Cadmium	1.02E-01	-	-
	Manganese and compounds	-	4.58E+00	-
	Mercury Vapor	-	1.40E-04	-
	Nickel Metal	-	1.19E-01	-

Emission Source	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
ES-11b (LCB3) Model ID LIMEDROP (8 drop points)	Arsenic and inorganic arsenic compounds	1.03E-01	-	-
	Beryllium	8.20E-02	-	-
	Cadmium	1.02E-01	-	-
	Manganese and compounds	-	4.58E+00	-
	Mercury Vapor	-	1.40E-04	-
	Nickel Metal	-	1.19E-01	-
ES-13a (LCB3a), ES-15 (SCB4), ES-16 (SCB5), ES-17 (LS1), ES-18 (LS2) Common exhaust point through bagfilter CD (LPTTBf) Model ID DUSTLPTT	Arsenic and inorganic arsenic compounds	1.57E-01	-	-
	Beryllium	1.25E-01	-	-
	Cadmium	1.55E-01	-	-
	Manganese and compounds	-	6.99E+00	-
	Mercury Vapor	-	2.14E-04	-
	Nickel Metal	-	1.82E-01	-
ES-19 (LCB6) Model ID LIMEDROP (8 drop points)	Arsenic and inorganic arsenic compounds	1.03E-01	-	-
	Beryllium	8.20E-02	-	-
	Cadmium	1.02E-01	-	-
	Manganese and compounds	-	4.58E+00	-
	Mercury Vapor	-	1.40E-04	-
	Nickel Metal	-	1.19E-01	-
ES-20 (LCB7) Model ID LIMEDROP (8 drop points)	Arsenic and inorganic arsenic compounds	1.03E-01	-	-
	Beryllium	8.20E-02	-	-
	Cadmium	1.02E-01	-	-
	Manganese and compounds	-	4.58E+00	-
	Mercury Vapor	-	1.40E-04	-
	Nickel Metal	-	1.19E-01	-
ES-21 (BM1) Model ID LIMEDROP (8 drop points)	Arsenic and inorganic arsenic compounds	1.03E-01	-	-
	Beryllium	8.20E-02	-	-
	Cadmium	1.02E-01	-	-
	Manganese and compounds	-	4.58E+00	-
	Mercury Vapor	-	1.40E-04	-
	Nickel Metal	-	1.19E-01	-
ES-22 (BM2) Model ID LIMEDROP (8 drop points)	Arsenic and inorganic arsenic compounds	1.03E-01	-	-
	Beryllium	8.20E-02	-	-
	Cadmium	1.02E-01	-	-
	Manganese and compounds	-	4.58E+00	-

Emission Source	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
	Mercury Vapor	-	1.40E-04	-
	Nickel Metal	-	1.19E-01	-
ES-33a (Silo,wwtf) Model ID ES33a	Arsenic and inorganic arsenic compounds	7.27E-02	-	-
	Beryllium	5.78E-02	-	-
	Cadmium	7.16E-02	-	-
	Manganese and compounds	-	3.23E+00	-
	Mercury Vapor	-	9.89E-05	-
	Nickel Metal	-	8.40E-02	-
ES-33b(Silo,wwtf) Model ID ES33b	Arsenic and inorganic arsenic compounds	7.27E-02	-	-
	Beryllium	5.78E-02	-	-
	Cadmium	7.16E-02	-	-
	Manganese and compounds	-	3.23E+00	-
	Mercury Vapor	-	9.89E-05	-
	Nickel Metal	-	8.40E-02	-
ES-U1SorbSilo Model ID ESU1A	Arsenic and inorganic arsenic compounds	1.85E-01	-	-
	Beryllium	1.95E-01	-	-
	Cadmium	1.90E-01	-	-
	Manganese and compounds	-	4.01E+00	-
	Mercury Vapor	-	2.18E-04	-
	Nickel Metal	-	2.22E-01	-
ES-U2SorbSilo Model ID ESU2A	Arsenic and inorganic arsenic compounds	1.85E-01	-	-
	Beryllium	1.95E-01	-	-
	Cadmium	1.90E-01	-	-
	Manganese and compounds	-	4.01E+00	-
	Mercury Vapor	-	2.18E-04	-
	Nickel Metal	-	2.22E-01	-
ES-U1WHopper1 , ES-U1Whopper2, ES-U1Whopper3 Model ID ESU1B	Arsenic and inorganic arsenic compounds	1.85E-01	-	-
	Beryllium	1.95E-01	-	-
	Cadmium	1.90E-01	-	-
	Manganese and compounds	-	4.01E+00	-
	Mercury Vapor	-	2.18E-04	-
	Nickel Metal	-	2.22E-01	-
ES-U2WHopper1 , ES-U2Whopper2, ES-U1Whopper3	Arsenic and inorganic arsenic compounds	1.85E-01	-	-
	Beryllium	1.95E-01	-	-

Emission Source	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
Model ID ESU2B	Cadmium	1.90E-01	-	-
	Manganese and compounds	-	4.01E+00	-
	Mercury Vapor	-	2.18E-04	-
	Nickel Metal	-	2.22E-01	-
ES-TS-1 Model ID DFABAG	Arsenic and inorganic arsenic compounds	1.79E+00	-	-
	Beryllium	2.03E+00	-	-
	Cadmium	3.23E-01	-	-
	Manganese and compounds	-	3.73E+00	-
	Mercury Vapor	-	4.71E-03	-
	Nickel Metal	-	1.42E+00	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	1.67E-01	-
SILO-3 and SILO-5 Model ID SILO3-5 Redundant bagilter CD-BF-6 on SILO-3 and SILO-5	Arsenic and inorganic arsenic compounds	1.37E+01	-	-
	Beryllium	1.55E+01	-	-
	Cadmium	2.47E+00	-	-
	Manganese and compounds	-	2.85E+01	-
	Mercury Vapor	-	3.61E-02	-
	Nickel Metal	-	1.09E+01	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	1.28E+00	-
DOME-1 (Storage Dome) Model ID DOME-1	Arsenic and inorganic arsenic compounds	9.46E+00	-	-
	Beryllium	1.08E+01	-	-
	Cadmium	1.71E+00	-	-
	Manganese and compounds	-	1.97E+01	-
	Mercury Vapor	-	2.50E-02	-
	Nickel Metal	-	7.52E+00	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	8.82E-01	-
SILO-3 (Ash Silo 3) Model ID SILO-3	Arsenic and inorganic arsenic compounds	2.73E+01	-	-
	Beryllium	3.11E+01	-	-
	Cadmium	4.94E+00	-	-
	Manganese and compounds	-	5.70E+01	-
	Mercury Vapor	-	7.21E-02	-
	Nickel Metal	-	2.17E+01	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	2.55E+00	-

Emission Source	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
SILO-4 (Ash Silo 4) and DFAL-4a (Dry Flyash Truck Loadout) Model ID SILO-4	Arsenic and inorganic arsenic compounds	6.31E+00	-	-
	Beryllium	7.17E+00	-	-
	Cadmium	1.14E+00	-	-
	Manganese and compounds	-	1.32E+01	-
	Mercury Vapor	-	1.66E-02	-
	Nickel Metal	-	5.02E+00	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	5.88E-01	-
SILO-5 (Ash Silo 5) Model ID SILO-5	Arsenic and inorganic arsenic compounds	2.73E+01	-	-
	Beryllium	3.11E+01	-	-
	Cadmium	4.94E+00	-	-
	Manganese and compounds	-	5.70E+01	-
	Mercury Vapor	-	7.21E-02	-
	Nickel Metal	-	2.17E+01	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	2.55E+00	-
IES-70 Gypsum Radial Stacker Model ID GYPSTACKR	Arsenic and inorganic arsenic compounds	4.20E-01	-	-
	Cadmium	4.99E-01	-	-
	Manganese and compounds	-	3.26E+01	-
	Mercury Vapor	-	7.84E-03	-
	Nickel Metal	-	3.33E-01	-
IES-l Railcar Coal Unloading, Two Coal Drops Model ID RAILCAR, BUNKDROP, PILEDROP	Arsenic and inorganic arsenic compounds	1.67E+01	-	-
	Beryllium	1.89E+01	-	-
	Cadmium	3.02E+00	-	-
	Manganese and compounds	-	3.48E+01	-
	Mercury Vapor	-	4.40E-02	-
	Nickel Metal	-	1.33E+01	-
I-60 FGD Gypsum Landfill Drop Model ID GYPLAND, GYPDROP	Arsenic and inorganic arsenic compounds	8.40E-01	-	-
	Cadmium	9.99E-01	-	-
	Manganese and compounds	-	6.53E+01	-
	Mercury Vapor	-	1.57E-02	-
	Nickel Metal	-	6.66E-01	-
DFAL-4b Dry Flyash Truck Loadout	Arsenic and inorganic arsenic compounds	6.31E+00	-	-
	Beryllium	7.17E+00	-	-

Emission Source	Toxic Air Pollutant	Emission Limit (lb/yr)	Emission Limit (lb/day)	Emission Limit (lb/hr)
Model ID DFAL-4B	Cadmium	1.14E+00	-	-
	Manganese and compounds	-	1.32E+01	-
	Mercury Vapor	-	1.66E-02	-
	Nickel Metal	-	5.02E+00	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	5.88E-01	-
WFAL-3 Model ID WFAL-3	Arsenic and inorganic arsenic compounds	1.90E-01	-	-
	Beryllium	2.15E-01	-	-
	Cadmium	3.43E-02	-	-
	Manganese and compounds	-	3.95E-01	-
	Mercury Vapor	-	5.00E-04	-
	Nickel Metal	-	1.51E-01	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	1.77E-02	-
WFAL-5 Model ID WFAL-5	Arsenic and inorganic arsenic compounds	1.90E-01	-	-
	Beryllium	2.15E-01	-	-
	Cadmium	3.43E-02	-	-
	Manganese and compounds	-	3.95E-01	-
	Mercury Vapor	-	5.00E-04	-
	Nickel Metal	-	1.51E-01	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	1.77E-02	-
IES-73 FGD Gypsum Landfill Model ID GYPPILE	Arsenic and inorganic arsenic compounds	4.20E-01	-	-
	Cadmium	4.99E-01	-	-
	Manganese and compounds	-	3.26E+01	-
	Mercury Vapor	-	7.84E-03	-
	Nickel Metal	-	3.33E-01	-
I-60 Ash Landfill Model ID ASHLAND2 and IES -2 Ash Landfill Model ASHLAND	Arsenic and inorganic arsenic compounds	1.98E+03	-	-
	Beryllium	2.24E+03	-	-
	Cadmium	3.57E+02	-	-
	Manganese and compounds	-	4.12E+03	-
	Mercury Vapor	-	5.21E+00	-
	Nickel Metal	-	1.57E+03	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	1.84E+02	-

Emission Source	Toxic Air Pollutant	Emission Limit		
		(lb/yr)	(lb/day)	(lb/hr)
IES-2, I-60 Truck Ash Dump Model ID ASHDROP	Arsenic and inorganic arsenic compounds	1.05E+00	-	-
	Beryllium	1.20E+00	-	-
	Cadmium	1.90E-01	-	-
	Manganese and compounds	-	2.20E+00	-
	Mercury Vapor	-	2.78E-03	-
	Nickel Metal	-	8.37E-01	-
	Soluble Chromate Compounds as Chromium VI Equivalent	-	9.82E-02	-
IES-1 Coal Storage Pile Model ID COALP	Arsenic and inorganic arsenic compounds	1.32E+00	-	-
	Beryllium	1.50E+00	-	-
	Cadmium	2.38E-01	-	-
	Manganese and compounds	-	2.75E+00	-
	Mercury Vapor	-	3.48E-03	-
	Nickel Metal	-	1.05E+00	-
I-60, IES-67, IES-68, IES-69, IES-71, IES-73 Gypsum Pile Model ID GYPPILE	Arsenic and inorganic arsenic compounds	4.20E-01	-	-
	Cadmium	4.99E-01	-	-
	Manganese and compounds	-	3.26E+01	-
	Mercury Vapor	-	7.84E-03	-
	Nickel Metal	-	3.33E-01	-
ES-PIGGING Model ID FLARE, PIG RECEIVER	Ethyl Mercaptan	-	-	1.02E+01
	n-hexane	-	9.68E+04	-

In addition, a permit TPER limit condition for benzo(a)pyrene, P-dichlorobenzene and toluene was added to the permit in Section 2.2.D.1.b.

2. Two natural gas/coal-fired electric utility boilers equipped with alkaline-based fuel additive (ID Nos. ES-1 and ES-2), and associated flue gas conditioning systems (ID Nos. CD-1, CD-1A, CD-4, and CD-4A), low NOx burner systems (ID Nos. CD-2 and CD-5), SCR (ID Nos. CD-2A and CD-5A), hydrated lime dry sorbent injection (ID Nos. CD-U1DSI and CD-U2DSI, electrostatic precipitators (ID Nos. CD-3 and CD-6), and wet Flue Gas Desulfurization systems (ID Nos. CD (U1FGDa), CD (U1FGDb), CD (U2FGDa) and CD (U2FGDb))

Two natural gas-fired auxiliary boilers (ID Nos. ES-3 and ES-4)

Four natural gas-fired, natural gas supply line heaters (ID Nos. ES-34a, ES-34b, ES-34c and ES-34d)

Natural gas supply line pigging operation including fugitive emissions from pig receiver vent (ID No. ES-PIGGING) with associated temporary flare of natural gas from supply line (ID No. CD-PIG FLARE)

15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT
Pursuant to 15A NCAC 02Q .0501(b)(2) or (c)(2), for completion of the two-step significant modification process initiated by Application No. (8500004.18A), the Permittee shall file an amended application following the procedures of Section 15A NCAC 02Q .0500 within one year from the date the first of these sources (ID Nos. ES-1, ES-2, ES-3, ES-4, ES-34a, ES-34b, ES-34c and ES-34d) to begin burning natural gas.

6.0 BACT Analysis

6.1 Introduction

The PSD regulations (40 CFR 51.166) and North Carolina air regulations (15A NCAC 02D .0530) require a Best Available Control Technology (BACT) analysis for modified emission units at an existing major source that will have an increase in emissions of a PSD-regulated compound subject to PSD review. Post project, both Unit 1 and Unit 2 will have the capability to startup and shutdown on gas and to co-fire gas with coal. The actual fuel mix fired will be based on cost, availability, and demand. Auxiliary Boilers 1 and 2 will be converted to natural gas firing. Oil firing capability will be removed from Units 1 and 2 and the auxiliary boilers. PNG will also install four 8 million British thermal units per hour (mmBtu/hr) natural gas heaters on the new natural gas supply line. The natural gas line on the site will also include a pig receiving station that will be infrequently used for pipeline cleaning and inspection.

As stated in Section 4.0, the project triggers PSD review for CO and VOCs (see Table 1) and the new and modified emissions units will be subject to BACT requirements for the modification.

BACT is defined in 40 CFR 51.166(b)(12) as:

> *… an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each a regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the reviewing authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

As evidenced by the statutory definition of BACT, this technology determination must include a consideration of numerous factors. The structural and procedural framework upon which a decision should be made is not prescribed by Congress under the Act nor by the EPA through any rule. DAQ makes their BACT determinations based on an evaluation of the statutory factors contained in the definition of BACT in the Clean Air Act.

The EPA has issued guidance encouraging all PSD applicants to use the "top-down" approach to BACT. While the EPA Environmental Appeals Board recognizes the “top-down” approach for delegated state agencies,[1] this procedure has never undergone rulemaking. As such, the “top-down” process is not binding on fully approved

[1] See http://es.epa.gov/oeca/enforcement/envappeal.html for various PSD appeals board decisions including standard for review.

states, including North Carolina.[2] In this case, the applicant's BACT analysis is consistent with the EPA based "top-down" approach. However, NC DAQ does not strictly adhere to EPA's top-down guidance. Rather DAQ implements BACT in strict accordance with the statutory and regulatory language. As such, DAQ's BACT conclusions may differ from those of the applicant or EPA.

In order to identify potential controls, previous BACT determinations, as well as EPA's RACT/BACT/LAER Clearinghouse (RBLC) were reviewed.

Based on the controlled emission rates of regulated air pollutants, the facility is subject to the BACT requirements for the discharge of CO and VOCs.

6.2 BACT Analysis for CO and VOC Emissions

Combustion is a thermal oxidation process in which carbon, hydrogen, and sulfur contained in a fuel combine with oxygen in the combustion zone to form CO_2, H_2O, and SO_2. CO is generated during the combustion process as a result of incomplete thermal oxidation of the carbon contained within the fuel. VOCs are also generated due to incomplete combustion of fuel.

High levels of CO and VOC emissions result from poor burner design or sub-optimal firing conditions. With combustion technology/design control, formation of CO and VOC in the boiler is minimized by good combustion efficiency through optimum design and operation. This includes proper air-to-fuel ratios, and a boiler design that provides the necessary temperature, residence time and mixing conditions in the combustion zone.

Care must be taken when incorporating combustion design changes to reduce both NO_X and CO or VOC emissions. Combustion modifications associated with reduction of CO and VOC emissions can increase NO_X emissions and vice versa. For example, the use of low-NOx burners reduces flame temperature and thus reduces the NO_X formation in the combustion zone, but the same technique also leads to increases in products of incomplete combustion such as CO and VOCs. A good balance between these air pollutants must be achieved in order for combustion modification to be useful.

CO and VOC emissions are greater from burning natural gas than for burning coal.

<u>Identification of Control Technologies</u>

<u>Good Combustion Practices</u>
Optimization of the design, operation, and maintenance of the combustion system is the primary mechanism available for lowering CO and VOC emissions for natural gas and coal fired boilers and process heaters. This process is often referred to as combustion control or good combustion practices. The furnace/combustion system design provides all of the factors required to facilitate complete combustion. These factors include continuous mixing of air and fuel in the proper proportions, extended residence time, consistent proper temperatures in the combustion chamber, performing periodic observations of flame pattern, periodic burner inspections, annual stack testing, performing regular tune-ups and maintaining any fans and dampers in proper working condition. As a result, a properly designed furnace/combustion system is effective at limiting CO and VOC formation by maintaining the optimum furnace temperature and amount of excess oxygen. The addition of excess air and maintenance of high combustion temperatures for control of CO and VOC emissions can lead to an increase of NO_X emissions. Consequently, typical practice is to design the furnace/combustion system (specifically, the air/fuel mixture and furnace temperature) such that CO and VOC emissions are reduced as much as possible without causing NOx levels to significantly increase. Proper operation and maintenance of the furnace/combustion system will help to minimize the formation and emissions of CO and VOCs.

<u>Catalytic Oxidation</u>

[2] North Carolina has full authority to implement the PSD program, 40 CFR Sec. 52.1770.

Catalytic oxidation is an add-on or post combustion control technique for reducing emissions of CO and VOCs. The catalytic oxidation system is typically a passive reactor, which consists of a honeycomb grid of metal panels. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (450ºF - 1200ºF). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to lower the activation energy necessary for complete oxidation of these incomplete combustion byproducts to carbon dioxide and water. The active component of most catalytic oxidation systems is platinum metal, which has been applied over a metal or ceramic substrate. This technology can achieve CO reductions as high as 95% and VOC reductions up to 70%.

A major operating drawback of the catalytic oxidizer is that fine particles suspended in the exhaust gases can foul and poison the catalyst. The problem of catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device, however, this would require reheating the exhaust gases to the required operating temperature for the catalytic process. Another significant disadvantage of the catalytic oxidizer is that SO_2 in the flue gas stream may be oxidized to form SO_3. The resulting SO_3 may react with the moisture in the flue gas to create sulfuric acid mist.

The particulate matter and sulfur compounds present in the exhaust gases from coal combustion make catalytic oxidation technically infeasible for controlling CO emissions from Unit 1 or Unit 2. Moreover, catalytic oxidation has not been demonstrated in practice for small emissions units such as the natural gas heaters or infrequently operated equipment such as the auxiliary boilers. Thus, catalytic oxidation is eliminated from further consideration in the BACT analysis.

Thermal Oxidation

Thermal oxidation requires heat (temperatures typically between 1400ºF to 1600ºF) and oxygen to convert CO and VOC in the flue gas to CO_2 and H_2O. There are two general types of thermal oxidizers that are used for the control of CO and VOC emissions: regenerative thermal oxidization and recuperative thermal oxidization. Thermal oxidation has generally been utilized for emission reductions of CO and VOC in non-combustion sources and have not been demonstrated in practice on full scale operations nor are they commercially available for use on coal-fired utility boilers, auxiliary boilers or natural gas heaters and therefore thermal oxidation is eliminated from further consideration in the BACT analysis.

6.2.1 BACT Determinations for CO Emissions for Units 1 and 2, Auxiliary Boilers and Natural Gas Heaters

Units 1 and 2

DEC performed a search of EPA's RACT/BACT/LAER Clearinghouse (RBLC) that included CO BACT determinations since 2006 for utility boilers greater than 250 mmBtu/hr firing natural gas (Process Type 11.310). The RBLC search results are summarized in Table 5-1 of the application. The RBLC search shows five BACT determinations for gas fired units that are based on good combustion practices to minimize CO (of the seven determinations in Table 5-1, DAQ notes the two not showing a control method indicate "No controls feasible" in the RBLC data, which is essentially the same as good combustion practices). Although one BACT determination for a gas-fired unit suggested that oxidation catalyst was required to control CO emissions, a review of the permit issued for the facility indicates that catalytic controls were not required for the listed boiler. DEC found the range of BACT limits for similar units in the RBLC for CO is 0.08 to 0.465 lb/mmBtu for gas-fired units.

DEC's RBLC search included CO BACT determinations since 2006 for utility boilers greater than 250 mmBtu/hr firing coal (Process Type 11.110). The RBLC search results are summarized in Table 5-2 of the application. There are 40 BACT determinations for CO from coal-fired utility boilers and none of the determinations indicate that add-on controls were required. The majority of these determinations explicitly identify good combustion practices as the emission control technique; however, it is likely that all of the determinations are based on good combustion practices. DEC found the range of BACT limits for similar units in the RBLC for CO is 0.1 to 0.5 lb/mmBtu for coal fired units.

Results of DEC's BACT analysis indicate that BACT for CO emissions from Units 1 and 2 when firing natural gas or co-firing natural gas with coal is a work practice approach. DEC indicates they will implement good combustion practices as BACT and that this is ensured by maintaining a proper excess air level, performing periodic observations of flame pattern, periodic burner inspections, annual stack testing, and performing regular tune-ups. DEC's proposed BACT limit for CO emissions from Units 1 and 2 when firing gas or gas with coal is 0.08 lb/mmBtu (6-hour average). DEC notes that this BACT limit is based on vendor guarantees and is equivalent to the BACT limit recently permitted for Cliffside Unit 5 for natural gas co-firing.

DAQ has reviewed the RBLC data for gas-fired utility boilers greater than 250 mmBtu/hr (Process Type 11.310) for the same period DEC used (1/1/06 to 1/31/19) to evaluate the BACT for CO. The search returned 81 facility determinations; however, most are not applicable. As examples, determinations IN-0234 at CO of 0.0365 lb/mmBtu, IL-0114 at CO of 0.02 lb/mmBtu and LA-0315 at CO of 0.035 lb/mmBtu are not applicable because IN-0234 and IL-0114 are not utility boilers (i.e., not SIC 4911/4931), IN-0234 is associated with a stationary corn wet milling plant, IL-0114 is a chemical production facility, and LA-0315 will be a natural gas to gasoline production facility. DAQ's search of the RBLC confirmed DEC's results that good combustion practices are BACT for CO in the range of 0.08 to 0.465 lb/mmBtu for burning natural gas.

DAQ has also reviewed RBLC data for coal-fired utility boilers greater than 250 mmBtu/hr (Process Type 11.110) for the same period Duke used (1/1/06 to 9/18/18) to evaluate the BACT for CO. The search returned 69 facility determinations and confirmed DEC's search results ranging from 0.1 to 0.5 lb/mmBtu.

DEC states they will conduct annual CO stack testing using the EPA reference test method for a minimum of 6 hours to demonstrate compliance with the BACT limit. As good combustion practices, DEC will perform periodic tune-ups on Units 1 and 2 as required under MATS to ensure good combustion during normal operation. For periods of startup and shutdown, DEC proposes the use of startup and shutdown work practices similar to those listed in Table 3 of 40 CFR 63, Subpart UUUUU (MATS) as BACT. These work practices to be placed in the permit are:

i. For startup of a unit, the Permittee shall use clean fuels as defined in §63.10042 for ignition. When firing coal, the Permittee shall utilize all of the applicable control technologies except dry scrubber and SCR. The Permittee shall start dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation.

ii. While firing coal during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in §63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

iii. Clean fuel means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) oil, including those fuels meeting the requirements of 40 CFR part 80, subpart I ("Subpart I-Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel").

DAQ agrees that DEC's proposed BACT limit for CO emissions from Units 1 and 2 when firing gas or gas with coal at 0.08 lb/mmBtu (6-hour average) is BACT during all operations except startups and shutdowns, with work practices used during startups and shutdowns. This is the same BACT limit established for the recently permitted Cliffside Unit 5 natural gas co-firing project determination and lower than the Unit 6 BACT limit of 0.12 lb/mmBtu for that project.

Auxiliary Boilers

Auxiliary Boilers 1 and 2 are infrequently operated and used to provide steam for heating up Units 1 and 2 during startup. Projected actual emissions for each boiler are 2 tons CO per year.

The RBLC search as summarized as Table 5-3 of the application includes six BACT determinations for gas-fired auxiliary boilers ranging from 0.0013 to 0.082 lb/mmBtu. The determinations resulted in a requirement for good combustion practices (no add-on controls). Duke Energy does not use add-on controls to reduce CO emissions from its auxiliary boilers. None of the BACT determinations established catalytic oxidation or thermal oxidation as BACT for CO for a gas-fired auxiliary boiler. Duke Energy does not utilize catalytic oxidation or thermal oxidation to control CO emissions from auxiliary boilers at any of its facilities.

Based on vendor guarantees following retrofitting of the auxiliary boiler with natural gas burners, DEC's proposed BACT is 0.08 lb/mmBtu (6-hr average). DEC states this value is within the range of RBLC results and is appropriate for a retrofitted boiler. DEC will meet this limit by firing pipeline quality natural gas and conducting tune-ups no less frequently than required under 40 CFR 63, Subpart DDDDD. Due to the intermittent operation of these units and low emissions from these units DEC requests that stack testing not be required for these units.

DAQ's review of RBLC determinations since 2006 for industrial sized boilers with heat inputs between 100 and 250 mmBtu/hr burning natural gas (Process Type 12.310) showed several facilities using good combustion practices for similar sized auxiliary boilers with BACT determinations near 0.036 lb/mmBtu (IN-0287 (Duke energy) at 0.036 lb/mmBtu (draft determination), VA-0328 at 0.037 lb/mmBtu (draft), VA-325 at 0.035 lb/mmBtu (draft), OH-0354 at 0.036 lb/mmBtu and MI-0389 at 0.035 lb/mmBtu). DEC's RBLC search, ranging from 0.0013 to 0.082 lb/mmBtu, included three determinations with CO limits of 0.036 lb/mmBtu. Based on this search, DAQ questioned DEC on whether the higher proposed 0.08 lb/mmBtu CO BACT limit was appropriate. DEC argues that IN-0287, VA-0328, VA-0325 and OH-0354 are new installations, not retrofit applications; most are draft, not final, determinations; and that MI-0398 is a case-by-case, not a BACT determination, and as noted above. As DEC notes, achieving efficient combustion and optimum design and operation is much easier in a new installation where all of the boiler parameters can be designed to peak conditions; whereas, the Belews Creek auxiliary boilers will be retrofitted to accommodate natural gas firing. Because of this retrofit, vendors will minimize emissions as best they can with the existing configuration; however, emissions will inherently be higher than a greenfield installation because there are some combustion parameters that cannot be changed/optimized as part of the modification. Therefore, DEC proposes to retain the proposed 0.08 lb/mmBtu CO limit.

DAQ concludes DEC's proposed BACT limit of 0.08 lb/mmBtu is appropriate for CO emissions. However, DAQ will require one-time CO stack testing.

Natural Gas Heaters

Four 8 million Btu/hr natural gas-fired heaters will be used to temperature-precondition natural gas prior to combustion at the facility. Potential emissions from all four units combined will be approximately 12.8 tons CO per year. The RBLC has only a few determinations for natural gas heaters; however, these units are two orders of magnitude larger than the ones to be installed with this project. Although not directly applicable, all RBLC determinations were based on use of good combustion practices with no add-on pollution controls. Add-on pollution controls are not feasible for these small natural gas-fired units. Duke Energy does not use add-on control devices for any of its small natural gas heaters.

The proposed BACT limit, based on vendor guarantees, is 0.0914 lb/mmBtu. DEC will meet this limit utilizing good combustion practices and by conducting periodic tune ups as required by 40 CFR 63, Subpart DDDDD. Due to the small size of these units, a typical stack configuration incompatible with Reference Method testing, and low emissions from these units DEC requests that stack testing not be required for these units.

DAQ agrees with DEC's proposed BACT for these natural gas-fired heaters and that no stack testing is required.

Economic Impacts

There are no adverse economic impacts associated with implementation of good combustion controls on Units 1 or 2, Auxiliary Boilers 1 or 2, or the natural gas heaters.

Environmental and Energy Impacts

There are no adverse environmental or energy impacts associated with implementation of good combustion controls on Unit 1 or Unit 2, Auxiliary Boilers 1 or 2, or the natural gas heaters.

6.2.2 BACT Determinations for VOC Emissions for Units 1 and 2, Auxiliary Boilers and Natural Gas Heaters

Units 1 and 2

DEC performed a search of EPA's RBLC that included VOC BACT determinations since 2008 from boilers greater than 250 mmBtu/hr firing natural gas (Process Type 11.310). The search results are presented in Table 5-4 of the application. The only BACT limit for a similar gas-fired unit found in the RBLC is equivalent to 0.0055 lb/mmBtu (CT-0156). This determination indicated that the boiler was required to install catalytic oxidation to control VOC emissions, although a review of the permit indicates that catalytic controls were not required for the listed boiler. DEC does not use add-on controls to reduce VOC emissions from its utility boilers.

DEC's search of EPA's RBLC included VOC BACT determinations since 2008 from boilers greater than 250 mmBtu/hr firing coal and results are presented in Table 5-5 of the application. DEC found that VOC the coal-fired utility boilers in the RBLC have BACT limits predominantly in the 0.003 to 0.004 lb/mmBtu range, but these values do not represent gas firing or co-firing of coal with higher VOC-emitting natural gas.

DEC's Results of the BACT analysis indicate that BACT for VOC emissions from Units 1 and 2 when firing gas or gas and coal is a work practice approach.

DEC states they will implement good combustion practices as BACT by maintaining a proper excess air level, performing periodic observations of flame pattern, periodic burner inspections, annual stack testing, and performing regular tune-ups. DEC notes that Cliffside Units 5 and 6 were recently permitted with a VOC BACT limit of 0.0055 lb/mmBtu (6-hour average) for gas firing. One coal-fired unit (AR-0094, John Turk Power Plant PC Boiler) has a VOC BACT limit of 0.0008 lb/mmBtu, but according to the company's website, this unit was installed in 2012 as a first of its kind "ultra-supercritical" unit, referred to as "advanced coal combustion technology." This unit is not representative of Unit 1 and 2's design or operation.

DEC's proposed BACT limit for Units 1 and 2 for gas firing or co-firing gas and coal is 0.0055 lb/mmBtu (6-hr average) based on vendor guarantees (the guarantee is for firing natural gas only) and the recent Cliffside 5 VOC BACT limits. DEC states they will conduct annual VOC stack testing while firing a mixture of coal and gas using the EPA reference test method for a minimum of 6 hours to demonstrate compliance with the BACT limit. As good combustion practices, DEC will perform periodic tune-ups on Units 1 and 2 as required under MATS to ensure good combustion during normal operation. For periods of startup and shutdown, DEC proposes the use of startup and shutdown work practices similar to those listed in Table 3 of 40 CFR 63, Subpart UUUUU (MATS) as BACT. These work practices to be placed in the permit will cover both CO and VOCs as shown in Section 6.2.1 above for CO.

DAQ has reviewed the RBLC data for gas-fired utility boilers for gas (Process Type 11.310) for the same period Duke used (1/1/06 to 1/31/19 to evaluate the BACT for VOCs. The search returned 51 facility determinations; however, most are not applicable. DAQ found several determinations that confirmed DEC's same proposed VOC limit of 0.0055 lb/mmBtu when burning natural gas, although those are for smaller boilers (ie: AL-0271, VA-0320, LA-0254) as there is only one determination in the time period selected for a similar size utility boiler at 0.0055 lb/mmBtu (AR-0094, as noted above). Therefore, DAQ agrees with DEC's proposed limit of a gas-only limit of 0.0055 lb/mmBtu. This is the same limit recently permitted for Cliffside 5 and 6 for natural gas only.

DAQ's RBLC search indicates several coal-only determinations in the 0.003 to 0.0036 lb/mmBtu range (TX-0585, MI-0399, TX-0554, MI-0389, OH-0310 and MO-0077) which confirms DEC's search.

DAQ considered whether a weighted gas/coal average VOC limit would be appropriate when burning a mixture of gas and coal which accounts for the lower VOC emissions from coal as seen in previous coal-only BACT determinations. This approach[3] which accounts for the coal contribution was permitted for the recent Cliffside 6 VOC BACT determination. However, DEC provided some additional information to supplement the application and argues that the proposed VOC limit of 0.0055 lb/mmBtu for Units 1 and 2 at Belews Creek is more appropriate than imposing the Cliffside Unit 6 weighted limit which applied to a relatively new coal-fired unit with different boiler characteristics and not a retrofit application where the combustion parameters cannot be optimized to achieve the low emission rates seen on greenfield installations. The following information provided by DEC from their equipment engineers for a comparison of Belews Creek Units 1 and 2 to Cliffside Unit 6 indicates the differences between the boiler design parameters and that Cliffside 6 and Belews Creek are not an "apples-to-apples" comparison.

- Burner design and combustion efficiency impacts flame propagation and length. A minimum furnace residence time is necessary to ensure complete combustion within a given amount of furnace residence time which is calculated from the top burner to furnace exit. Less than optimal combustion efficiency with a retrofitted design will also increase VOC emissions since VOC emissions are minimized with proper combustion that promotes good mixing at the burners. Since the original Belews Creek cell burners had a very high heat release rate, these were retrofitted with overfire air (OFA) and DRB-XCL low NOx burners. Since then, there has been an upward shift in the staging of combustion that has changed the firing intensity in the lower furnace and negatively influenced residence time for the Belews Creek units.
- Burner zone heat release rate affects the thermal NOx formation in the furnace (e.g. higher temperature = higher VOC destruction = higher NOx emissions). Since the Belews Creek furnace was originally designed with a high release cell burner arrangement and later retrofitted with lower heat release DRB-XCL low NOx burners, this has shifted the fireball upward and is a very different firing arrangement as compared to the Cliffside 6 boiler design. The figure below shows the variation from where Belews Creek was originally to the expected retrofit design and compared to Cliffside Unit 6.

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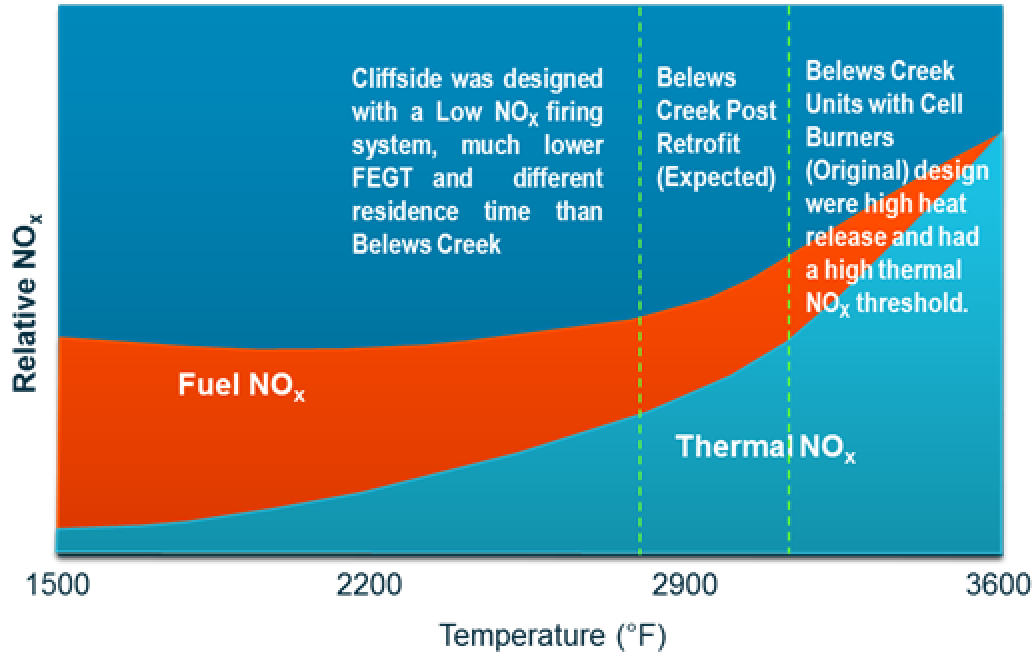
[3] $E_{gc} = (E_g * Q_g + E_c * Q_c)/Q_t$ (6-hour average)

Where:
E_{gc} = BACT for natural gas and coal co-firing, lb/million Btu
E_g = 0.08 lb/million Btu
E_c = 0.003 lb/million Btu
Q_g = natural gas heat input in million Btu
Q_c = coal heat input in million Btu
$Q_t = Q_g + Q_c$



- The Belews Creek design furnace exit gas temperature (FEGT) is greater than 2,400ºF and is one of the highest heat release boilers in DEC's fleet, compared to Cliffside 6 at less than 2,200ºF. Because of this, the inefficiencies of firing natural gas mixed with less radiant heat transfer at Belews Creek can increase FEGT further and push a small percent of high sulfur fuel well beyond the fluid temperature of the ash, allowing it to stick to heating surfaces and/or burners, negatively influencing combustion.
- The age of the Belews Creek boilers is also very different and promotes the degradation of gas tightness, allowing the onset of some air in-leakage (which we have measured in the past). This in turn impacts the amount of excess air required since air in-leakage can induce insufficient combustion air, poor airflow distribution, poor mixing in the burner zone or burner mechanical problems.
- Cliffside 6 has advanced coal milling systems with automated hydraulics, dynamic classifiers to help automate and optimize combustion, while Belews Creek milling systems have static hydraulic systems and centrifugal classifiers.

Considering the above, DAQ agrees that the Belews Creek boilers retrofitted for gas burning cannot be directly compared to the Cliffside 6 design, and that DEC's proposed BACT limit for VOC emissions from Units 1 and 2 when firing gas or gas with coal at 0.0055 lb/mmBtu (6-hour average) is BACT during all operations except startups and shutdowns, with work practices used during startups and shutdowns. The work practice standards shown in Section 6.2.1 for CO will apply for startups and shutdowns for VOCs.

Auxiliary Boilers

Auxiliary Boilers 1 and 2 are infrequently operated and used to provide steam for heat-up of Units 1 and 2 during startup conditions. Total projected actual emissions for each boiler are approximately 0.14 tons VOC per year. DEC's RBLC determinations as presented in Table 5-6 of the application for auxiliary boilers are generally 0.0055 lb/mmBtu. DEC proposes a limit of 0.0055 lb/mmBtu (6-hr average) based on vendor guarantees and the recent BACT limits permitted at Cliffside utility boilers 5 and 6. DEC will meet this limit by conducting tune-ups no less frequently than required for limited use boilers under 40 CFR 63, Subpart DDDDD. Due to the intermittent operating of these units and relatively low emissions from these units DEC requests that stack testing not be required.

DAQ's review of RBLC determinations since 2006 for industrial sized boilers with heat inputs between 100 and 250 mmBtu/hr burning natural gas (Process Type 12.310) showed a couple facilities for similar sized auxiliary boilers with BACT determinations lower than DEC's proposed limit of 0.0055 lb/mmBtu (MI-0389 at 0.0013 lb/mmBtu and MI-0423 at 0.004 lb/mmBtu) in addition to a lower limit of 0.0014 lb/mmBtu (IA-0105) as DEC found. Based on this search, DAQ questioned DEC on whether the higher proposed 0.0055 lb/mmBtu VOC BACT limit was appropriate. DEC argues that the above three determinations are for new installations, not retrofit applications. DEC notes, achieving efficient combustion and optimum design and operation is much easier in a new installation where all of the boiler parameters can be designed to peak conditions; whereas, the Belews Creek auxiliary boilers will be retrofitted to accommodate natural gas firing. Because of this retrofit, vendors will minimize emissions as best they can with the existing configuration, however, emissions will be inherently higher than a greenfield installation because there are some combustion parameters that cannot be changed/optimized as part of the modification. Therefore, DEC proposes to retain the proposed 0.0055 lb/mmBtu VOC limit.

DAQ concludes DEC's proposed BACT limit of 0.0055 lb/mmBtu is appropriate for VOC emissions. However, DAQ will require one-time CO stack testing.

<u>Natural Gas Heaters</u>
Four 8 million Btu/hr natural gas fired heaters will be used to temperature precondition natural gas prior to combustion at the station. Potential emissions from all four units combined will be approximately 9 tons VOC per year. The RBLC does not contain any determinations for VOC emitted from small natural gas heaters.

The proposed BACT limit based on vendor guarantees is 0.0644 lb/mmBtu. DEC will meet this limit utilizing good combustion practices and periodic tune ups as required by 40 CFR 63, Subpart DDDDD. Due to the small size of these units, a typical stack configuration that would not lend itself to Reference Method testing, and low emissions from these units DEC requests that stack testing not be required for these units.

DAQ agrees with DEC's proposed BACT for these natural gas-fired heaters and that no stack testing is required.

<u>Economic Impacts</u>
There are no adverse economic impacts associated with implementation of good combustion controls on Units 1 or 2, Auxiliary Boilers 1 or 2, or the natural gas heaters.

<u>Environmental and Energy Impacts</u>
There are no adverse environmental or energy impacts associated with implementation of good combustion controls on Unit 1 or Unit 2, Auxiliary Boilers 1 or 2, or the natural gas heaters.

6.3 BACT Analysis for CO and VOC Emissions for Gas Line Pigging

Pigging operations are designed to periodically clean and inspect the natural gas pipeline and are considered a maintenance activity. The motive force to drive the pig through the pipeline is typically air during initial commissioning prior to energizing the pipeline with natural gas. Following initial commissioning, natural gas will be used to drive the pig. These activities are routine for the natural gas transmission industry and are anticipated to be conducted at most seven times per year at 1.75 hours per event. There are two types of emissions that occur during pigging: 1) emissions that occur due to venting the pipeline natural gas after the pig is launched until it arrives at the receiver, and 2) fugitive emissions from the pig receiver that occur during pig retrieval. Potential emissions are estimated based on up to seven pig launches per maintenance activity.

Due to the significant volume of natural gas that is typically vented during pigging events, a flare is typically used to combust the natural gas (resulting in CO and VOC emissions). Due to the infrequent nature of these operations, use of other combustion technologies is not needed and otherwise is impractical. Use of a flare is the proposed control technology for pipeline venting during pigging operations. A relatively minute amount of natural gas is released as a fugitive from the pig receiver when it is opened. Due to the impracticality of controlling these fugitives, standard industry practice is to vent this small quantity of gas. No RBLC determinations for pigging operations were located.

The proposed flare for this process will be adequately sized and designed for combustion of the natural gas that will be vented. Prior to each scheduled day for pigging, the flare will be inspected and maintained in accordance with the manufacturer's recommendations and a record of this activity maintained. A copy of the recommended inspection and maintenance procedure will be maintained at the site and any deviations from standard protocols due to site-specific considerations will be documented and maintained. The work practice standard for the receiver will be to keep access openings to the receivers closed at all times except when a pig is being placed into or removed from the receiver, or during active maintenance operations.

DEC proposed that the BACT determination for these pigging operations be based on the above work practices and that a numerical emission limit not be established due to the impracticality of attempting to measure/demonstrate compliance with a numerical limit.

DAQ agrees with DEC's proposed BACT work practice control technology.

7.0 Air Quality Ambient Impact Analysis

As shown in Table 5, the total project emissions increases demonstrate that major New Source Review is required for VOCs and CO since emissions of those pollutants exceed their respective PSD significant emission rate (SER). Therefore, PSD regulations in 40 CFR 51.166 requires an air quality analysis for those pollutants.

7.1 Preliminary Class II Impact Modeling Analysis

An air quality preliminary impact analysis is conducted to determine if a full impact air quality analysis is needed and to define the impact area within which a full impact analysis is conducted. If the highest modeled concentrations for any pollutant and averaging period evaluated are less than the applicable SIL, a full impact air quality analysis is not required for that pollutant and averaging period.

A preliminary impact analysis was conducted for CO and VOCs since these pollutants exceed their respective SER (See Table 5). The modeling results were then compared to the applicable SILs as defined in Appendix W to determine if a full impact air quality analysis would be required for that pollutant.

DEC evaluated significant emissions using AERMOD 18081 model and five years (2012-2016) of meteorological data from surface (Winston-Salem) and upper air (Greensboro). Full terrain elevations were included, as were normal regulatory defaults. A preliminary PSD SIL Cartesian receptor grid system extending to 25 km from Belews Creek. Receptors were placed along the fence line at 25 m spacing. Receptor grid spacing increased with distance from the fence line. Optimized emission rates for this specific project were used and the maximum impacts were then compared to the SIL. Since the results showed impacts below the SIL for CO, no further modeling was required. Therefore, no NAAQS or increment consumption analysis is required. SIL results are shown in Table 7. No preconstruction monitoring is required due to the 8-hr CO value being less than the Significant Monitoring Concentration (SMC).

Table 7 - CO Modeled Significant Impact Levels

Pollutant	Averaging Period	Year	Maximum Modeled Impacts ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Percent of SIL	SMC ($\mu g/m^3$)	Percent of SMC
CO	1-hr	2014	338.4	2000	17%	--	--
	8-hr	2013	122.4	500	26%	575	21%

7.2 Secondary Ozone Impacts

As required by 40 CFR 51.166(m)(l)(i)(a), an ambient air quality analysis of project emission impacts was performed for VOC precursor secondary impacts on ozone. EPA's *Guidance on the Development of Modeled Emission Rates/or Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program* was used to show compliance for secondary ozone impacts. DEC used the MERPs values, established by EPA, for the Eastern United States. Conservatively, DEC shows the project emission increases for VOCs compared to the Eastern United States MERP as a percentage of significance. As shown in Table 8, project emissions are well below the EPA MERPs values. No ozone impacts are expected due to the project increases for VOCs. The MERP value used is found in the EPA MERPs Guidance (Table 7-1). The table below shows the project increases compared to the Eastern Region MERP for VOC as a percentage of significance.

Table 8. Project Emissions compared to MERPs.

Compound	Emissions (tpy)	MERP (tpy)	Percent of Significance
VOC	143.6	814	17.6%

7.3 Class I Impact Analysis

A Class I area impacts analysis is not required for this project because the project is not subject to PSD review for any pollutants that have Class I SILs or PSD increments. In an email 3-27-18 from Melanie Pitrolo (Federal Land Manager, FLM) to Tom Anderson (AQAB supervisor), DAQ was informed that based on the potential emissions from the project, it is not anticipated that there will be any adverse impacts to air quality related values (AQRVs) at Forest Service Class I areas and therefore the FLM would not be requesting that an AQRV modeling analysis be included as part of the permit application.

7.4 Additional Impacts Analysis

All PSD permit applicants are required to conduct additional impact analyses for each pollutant subject to PSD and which will be emitted by the proposed new or modified sources. The additional impact analysis assesses the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

Growth Impacts
The project will not result in any additional employees at the facility.

Soils and Vegetation
The modeled CO impacts 338.4 $\mu g/m^3$ (1-hr) and 122.4 $\mu g/m^3$ (8-hr) are well below the screening contractions of 1,800,000 $\mu g/m^3$ (1-week). Therefore, no significant impacts to soil and vegetation are expected from the project.

Visibility Impairment
A visible plume analysis is not required for this project because the project is not subject to PSD review for those pollutants that contribute to visible plume impacts (such as NOx and PM10/PM2.5).

8.0 Permit Changes

The following changes were made to the Duke Energy Carolinas LLC - Belews Creek Steam Station Air Permit No. 01983T33:

Old Page	Old Section	New Page	New Section	Description of Change(s)
cover	--	cover	--	Amended permit numbers and dates.
3-8	1, table of permitted emission sources	3-8	1, table of permitted emission sources	Revised emission source description for ES-1 and ES-2 from “No. 2 fuel oil/coal-fired electric utility boiler” to “natural gas/coal-fired electric utility boiler.” Revised emission source description for ES-3 (AuxB1) and ES-4 (AuxB2) from “Two No. 2 fuel oil-fired (propane for start-up only) auxiliary boilers” to “Two natural gas-fired auxiliary boilers.” Added sources: ES-34a, ES-34b, ES-34c, ES-34d and ES-PIGGING. Added second sentence to footnote 1. Added footnotes 8 and 9.

9	2.1.A, equipment description	9	2.1.A, equipment description	Revised from “coal/No. 2 fuel oil-fired electric utility boilers” to “natural gas/coal-fired electric utility boilers” Added note that the Permittee may operate these sources on oil under the provisions in Permit No. 01983T33 until the conversion to natural gas is complete.
9-10	2.1.A, regulation table	9-10	2.1.A, regulation table	Replaced oil with gas for 15A NCAC 02D .0519 limits. Added 15A NCAC 02D .0530, 15A NCAC 02D .0530(u) and 15A NCAC 02Q .0504.
11	2.1.A.2	11	2.1.A.2	Replaced oil with gas.
11	2.1.A.2.c	11	2.1.A.2.c	Removed redundant emission limits.
19	2.1.A.10.a	19	2.1.A.10.a	Replaced No. 2 fuel oil with natural gas.
--	--	28-30	2.1.A.12	Added 15A NCAC 02D .0530 PSD condition.
--	--	30	2.1.A.13	Added 15A NCAC 02D .0530(u) condition.
29	2.1.B, equipment description	31	2.1.B, equipment description	Revised from “No. 2 oil/propane” to “natural gas.” Added note that the Permittee may operate these sources on oil under the provisions in Permit No. 01983T33 until the conversion to natural gas is complete.
29	2.1.B, regulation table	31	2.1.B, regulation table	Added 15A NCAC 02D .0530, 15A NCAC 02D .0530(u) and 15A NCAC 02Q .0504.
30	2.1.B.3.c, d and e	32	2.1.B.3.c	Removed monitoring, recordkeeping and reporting for visible emissions.
31	2.5.B.5	33	2.1.B.5	Added note that this section is not shielded pursuant to 15A NCAC 2Q .0512(a). Added statement to allow operation under the Subpart DDDDD limited-use boiler provisions in Permit No. 01983T33 until startup on natural gas.
31	2.1.B.5.a	33	2.1.B.5.a	Revised requirements from limited-use boilers to the *Unit designed to burn gas 1 subcategory*. Removed noncompliance statements.
31	2.1.B.5.b	--	removed	
32	2.1.B.5.i	34	2.1.B.5.h	
32	2.1.B.5.j	34	2.1.B.5.i	
--	added	34	2.1.B.5.k	
32	2.1.B.5.m.i	34	2.1.B.5.l.i	
33	2.1.B.5.p	35	2.1.B.5.n	
--	--	35-36	2.1.B.6	Added 15A NCAC 02D .0530 PSD condition.
--	--	36-37	2.1.B.7	Added 15A NCAC 02D .0530(u) condition.
50	2.1.J.4.b	--	--	Removed reporting requirement to notify the Regional Office in writing of the date of beginning operation of sources and control

				devices ID Nos. ES-TS-1, CD-BF-7 and CD-BF-6 since this has been completed.
--	--	55-58	2.1.K	Added this section for the new natural gas-fired natural gas supply line heaters ES-34a, ES-34b, ES-34c, ES-34d.
--	--	59-60	2.1.L	Added this section for the natural gas supply line pigging operation ES-PIGGING.
54-62	2.2.D.1.a	64-71	2.2.D.1.a	Revised toxic emission limits.
--	--	71-72	2.2.D.2	Added TPER limit condition.
--	--	72	2.2.E.1	Added requirement to file an amended application for completion of the two-step significant modification process within one year from the date the first of sources ES-1, ES-2, ES-3, ES-4, ES-34a, ES-34b, ES-34c, ES-34d or ES-PIGGING begins to burn natural gas.

9.0. Public Participation

In accordance with 40 CFR 51.166(q), *Public participation,* the reviewing authority (DAQ) shall:

1. **Make available in at least one location in each region in which the proposed source would be constructed a copy of all materials the applicant submitted, a copy of the preliminary determination, and a copy or summary of other materials, if any, considered in making the preliminary determination.**

   These materials will be available at the Winston-Salem Regional Office located at 450 West Hanes Mill Road, Suite 300, Winston-Salem, NC 27105, phone number (336) 776-9800.

2. **Notify the public, by advertisement in a newspaper of general circulation in each region in which the proposed source would be constructed, of the application, the preliminary determination, the degree of increment consumption that is expected from the source or modification, and of the opportunity for comment at a public hearing as well as written public comment.**

   Pursuant to 15A NCAC 02Q .0307, the public notice of the draft permit will be published in the Winston-Salem Journal on March 4, 2019 to provide for a 30-day comment period with an opportunity for a public hearing. Appendix B contains a copy of the public notice. There is no increment consumption for this project.

3. **Send a copy of the notice of public comment to the applicant, the Administrator and to officials and agencies having cognizance over the location where the proposed construction would occur as follows: Any other State or local air pollution control agencies, the chief executives of the city and county where the source would be located; any comprehensive regional land use planning agency, and any State, Federal Land Manager, or Indian Governing body whose lands may be affected by emissions from the source or modification.**

   The public notice will be sent via email (US mail for the Winston-Salem County Manager) to the affected parties.

4. **Provide opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate consideration.**

   The public notice provides for the opportunity to request a public hearing for the modification.

5. **Consider all written comments submitted within a time specified in the notice of public comment and all comments received at any public hearing(s) in making a final decision on the approvability of the application. The reviewing authority shall make all comments available for public inspection in the same locations where the reviewing authority made available preconstruction information relating to the proposed source or modification.**

The DAQ will consider all timely comments submitted. All documents related to this determination, including comments received, will be available as public records at both the Regional Office and the Central Office.

6. **Make a final determination whether construction should be approved, approved with conditions, or disapproved.**

   After completion of the public notice process of the draft permit, DAQ will issue a final determination regarding the change.

7. **Notify the applicant in writing of the final determination and make such notification available for public inspection at the same location where the reviewing authority made available preconstruction information and public comments relating to the source.**

   The applicant will be informed of the final determination via a revised permit. All documents related to this determination, including comments received, will be available as public records at both the Regional Office and the Central Office.

Appendix C includes a mail listing of entities and associated materials to be sent for this proposed PSD major modification application, satisfying the requirements in §51.166(q) "public participation".

10.0 Other Requirements

PE Seal
The D5 form for technical portions of the application was sealed by Cynthia C. Winston, PE, Seal No. 030410 on June 20, 2018 pursuant to 15A NCAC 02Q .0112. This was not included in the original application as stated in the application "completeness" letter to DEC dated June 8, 2018 and was received June 21, 2018.

Zoning
A Zoning Consistency Determination form was received on May 23, 2018, signed and dated May 18, 2018 by David Sudderth with Stokes County Planning and Inspections.

Fee Classification
The facility fee classification before and after this modification will remain as "Title V".

Increment Tracking
Stokes County has triggered increment tracking under PSD for PM-10 and SO_2. However, this permit modification does not consume or expand increments for any pollutants since the lb/hr rates when burning 100% coal will not change.

11.0 Comments on Pre-Noticed Draft Permit

Comments from WSRO and SSCB
The pre-noticed draft permit and review were sent to Samir Parekh with Stationary Source Compliance Branch and Robert Barker at the Winston-Salem Regional Office on February 18, 2019 for review.

On February 19, 2019, in an email Robert Barker responded with the following comment:

1. On reviewing the draft Title V permit for Belews Creek, I only have one comment. Under 2.1.J.4.b, it requires notification to DAQ for the beginning operation of emission source ES-TS-1 and control devices CD-BF-7 and CD-BF-6, postmarked no later than 30 days after such date. This notification (report) has been received by DAQ. The facility sent DAQ the notification for operation for this source and control devices on March 19, 2018. ES-TS-1 and CD-BF-7 had a startup date of February 28, 2018 and CD-BF-6 had a startup date of February 26, 2018.

   Permitting Response

This change was made.

No comments were received from SSCB.

Comments from DEC

The pre-noticed draft permit and review were sent to Erin Wallace at DEC on February 20, 2019 for review. Duke responded on February 21 and 22, 2019 with the following major comments.

1. Do we need to have language added at Sections 2.1.A and 2.1.B equipment descriptions to allow for oil firing until the conversion is completed?

   DAQ Response

   Added notes that the Permittee may operate these sources on oil under the provisions in Permit No. 01983T33 until the conversion to natural gas is complete.

2. To be consistent with the Cliffside permit and others across the fleet, we respectfully request that the following footnote be added to the table of Permitted Sources:

   > *The control systems (ESP and SCR) may be operated independently of each other or in combination. Each system may be operated intermittently as necessary, based on boiler system requirements, to maintain compliance with applicable regulatory requirements.*

   DAQ Response

   DEC was notified that the ESPs can't be included in this footnote, as the MATs rule in Section 2.1.A.11.c.i of the permit, requires the Permittee to engage all applicable control technologies except the SCR, as follows:

   > *Once the unit converts to firing coal, the Permittee shall engage all of the applicable control technologies except the SCR. The Permittee shall start the SCR system appropriately to comply with relevant standards applicable during normal operation.*

   DAQ will add footnote 9 without the ESP to the table of Permitted Sources, as follows:

   > *The SCR NOx control system may be operated intermittently as necessary, based on boiler system requirements, to maintain compliance with applicable regulatory requirements.*

12.0 Comments on and Changes to Draft Permit (after public notice)

To be determined.

13.0 Recommendations

Based on the application submitted and review by the DAQ, the DAQ is making a preliminary determination that the modification can be approved and a permit issued. A final determination will be made following public notice and comment and consideration of all comments.

APPENDIX A

Draft Permit

APPENDIX B

Public Notice

APPENDIX C

Mail Listing

	Letters	Email
APPLICANT	Mr. Reginald Anderson, General Manager III Belews Creek Steam Station Duke Energy Carolinas LLC 3195 Pine Hall Rd. Belews Creek, NC 27009	Reginald.Anderson@duke-energy.com
WINSTON-SALEM REGIONAL OFFICE	Mr. Robert Barker 450 West Hanes Mill Road, Suite 300 Winston-Salem, NC 27105	robert.barker@ncdenr.gov
EPA	Ms. Ceron Heather Air Permits Section U.S. EPA Region 4 Sam Nunn Atlanta Federal Building 61 Forsyth Street, S.W. Atlanta, Georgia 30303-3104	ceron.heather@epa.gov
FLM	Ms. Andrea Stacy National Park Service Air Resources Division 12795 W. Alameda Pkwy P.O. Box 25287 Denver, CO 80225	andrea_stacy@nps.gov bjackson02@fs.fed.us jill_webster@fws.gov mpitrolo@fs.fed.us
COUNTY MANAGER	Mr. . Jake Oakley Stokes County Manager 1014 Main Street Danbury, NC 27016	cmanager@co.stokes.nc.us
NEWSPAPER	Classified Ads	Public Notice only