NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date: DRAFT

Region: Mooresville Regional Office
County: Rowan
NC Facility ID: 8000004
Inspector's Name: Joseph Foutz
Date of Last Inspection: 01/19/2017
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Duke Energy Carolinas, LLC - Buck Combined Cycle Facility

Facility Address:
Duke Energy Carolinas, LLC - Buck Combined Cycle Facility
1385 Dukeville Road
Salisbury, NC 28146

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 .0515, .0516, .0521, .0540, .0614, .1413
NSPS: Subpart IIII
NESHAP: Subpart ZZZZ
PSD: N/A
PSD Avoidance: N/A
NC Toxics: 02D .1100 and 02Q .0711
112(r): N/A
Other: N/A

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Dale Wooten Environmental Coordinator (704) 630-3086 1385 Dukeville Road Salisbury, NC 28146	Henry Botkins, Jr. General Manager (704) 630-3019 1385 Dukeville Road Salisbury, NC 28146	Daniel Markley Lead Environmental Specialist (704) 382-0696 526 South Church Street Charlotte, NC 28202

Application Data

Application Number: 8000004.17B
Date Received: 04/24/2017
Application Type: Modification
Application Schedule: TV-Sign-501(c)(2) Part I

Existing Permit Data

Existing Permit Number: 03786/T34
Existing Permit Issue Date: 01/30/2017
Existing Permit Expiration Date: 07/31/2021

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2015	10.60	147.07	9.42	15.73	67.12	2.26	1.08 [Hexane, n-]
2014	7.90	110.68	33.24	82.32	93.07	1.71	0.8222 [Hexane, n-]
2013	565.71	225.09	39.22	179.04	141.14	42.82	37.71 [Hydrogen chloride (hydrochlori]
2012	1421.36	348.60	41.48	295.56	220.15	112.36	102.60 [Hydrogen chloride (hydrochlori]
2011	3840.47	656.25	11.52	581.26	262.95	342.87	317.99 [Hydrogen chloride (hydrochlori]

Review Engineer: Kevin Godwin

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

Comments / Recommendations:

Issue 03786/T35
Permit Issue Date:
Permit Expiration Date: 07/31/2021

I. Purpose of Application

This application is for the first part of a two-step significant modification of the current Title V permit to install and operate a fly ash processing facility at the Duke Energy Carolinas, LLC Buck Combined Cycle Facility. The proposed facility is designed to annually process up to 400,000 tons of coal combustion fly ash with other ingredient materials to produce a high-quality class F fly ash for use in ready mix concrete or other commercial products. It uses a proprietary technology from the SEFA Group Inc. called STAR® - Staged Turbulent Air Reactor - to chemically and physically convert fly ash into a low-carbon material that meets the American Society for Testing and Materials (ASTM) Standard C618-08, "Standard Specification for Coal Fly Ash and Raw or Calcined Natural Pozzolan for Use in Concrete" of no more than 6 percent by weight loss-on-ignition (LOI) content to be suitable for use in concrete.

The STAR® system is equipped with a dry flue gas desulfurization (FGD) scrubber and bagfilter for emissions control and will be the primary source of new emissions. Additionally, the project will include feed, transfer, byproduct and loadout silos, heat exchangers, a screener and crusher with diesel engines, a storage dome and other material handling and storage operations.

During initial start-up of the STAR® reactor, combustion air is heated by low-NOx start-up burners firing natural gas or propane. These start-up burners have a combined heat input capacity of 60 million Btu's per hour. Fuel and fly ash are then co-fired until the fly ash auto-ignition temperature (approximately 1,400 degrees °F) is reached. At this temperature, residual carbon in the fly ash becomes the heat input source in the reactor, which is rated at 140 million Btu per hour heat input capacity. Although, under certain conditions, auxiliary fuel may be co-fired with the residual carbon in the fly ash.

Turbulence within the reactor ensures thorough mixing of air (oxygen) and carbon for the desired reaction to proceed. Oxidized fly ash gets entrained in the exhaust gas and exits out the top of the reactor and passes through a hot cyclone where a portion of the solids are returned to the reactor for temperature control. The fly ash and gasses leaving the hot cyclone are conveyed to the air preheater and gas coolers external heat exchangers. These units cool the flue gas to a temperature for which the product baghouse is rated and generate hot water to further dry the fly ash prior to entry into the reactor. The cooled flue gas is routed to a baghouse, where the product is collected and removed. Exhaust gases from the baghouse go to a dry FGD scrubber and bagfilter for emissions control before exiting through a stack (140 feet in height) into the atmosphere.[1]

The preparation of fly ash for beneficial use in the manner proposed by Duke Energy is encouraged by the U.S. Environmental Protection Agency (EPA). EPA finds "this practice can produce positive environmental, economic, and product benefits such as reduced use of virgin resources, lower greenhouse gas emissions, reduced cost of coal ash disposal, and improved strength and durability of materials."[2]

2. Facility Description

The Buck Combined Cycle Plant is a 620-megawatt nominal capacity electric power generating facility located on the Yadkin River in Salisbury, Rowan County, N.C. It includes two fuel-efficient and clean burning combined cycle combustion turbine generators that burn natural gas to heat compressed air – which turns a turbine to generate electricity. These units recover heat from the

[1] Maryland Department of Natural of Natural Resources (DNR) Publication No. 12-382012-556Morgantown STAR ERD - Case No. 9229, March 2012.
[2] U.S. EPA, Coal Ash Reuse, https://www.epa.gov/coalash/coal-ash-reuse; Accessed May 10, 2017

exhaust gases to produce steam – which turns another turbine to produce additional electric power. This natural gas plant was placed into service in 2011 and is equipped with advanced emissions control. A selective catalytic reduction (SCR) unit reduces nitrogen oxide emissions and an oxidation catalyst minimizes carbon monoxide (CO) and VOC emissions.

The site originally began producing electricity in 1926 as a coal-fired steam station. However, all coal-fired units were retired in April 2013. The current natural gas plant is a cleaner source of energy with considerably lower emissions, including 92 percent less nitrogen oxides and nearly 100 percent less sulfur dioxide per unit of power generated than the former coal plant.

3. History/Background/Application Chronology

Oct. 15, 2002	Air Permit No. 103786T22 issued to add two combustion turbines (ES-11 and ES-12).
May 14, 2011	Three coal-fired boilers (ES-1, ES-2 and ES-3) were retired.
Dec. 23, 2011	Air Permit No. 103786T28 issued to revise the maximum horsepower ratings for the emergency generator and firewater pump and for the renewal of the Title IV acid rain program permit
Oct. 1, 2012	Air Permit No. 103786T29 issued to replace the 4,000-hour limit on the operation of the duct burners on the two combustion turbines (ES-11 and ES-12) with a maximum heat input limit of 2,480,000 mmBtu per year. Three simple cycle combustion turbines (ES-6 to ES-8) were retired.
Apr. 1, 2013	Two coal-fired boilers (ES-4 and ES-5) were retired.
Sep. 23, 2014	Air Permit No. 103786T30 issued for hot gas path modifications to the two combined cycle combustion turbines (ES-11 and ES-12).
Feb. 23, 2015	Air Permit No. 103786T31 issued to remove five coal/No. 2 fuel oil-fired electric utility boilers (ID Nos. ES-1 to ES-5); three No. 2 fuel oil/natural gas-fired simple-cycle combustion turbines (ID Nos. ES-6 to ES-8); one No. 2 fuel oil-fired auxiliary boiler (ID No. ES-9), rail-car unloading system (ES-10), and coal pile and handling (ES-1A) and for administrative changes.
Jun. 10, 2015	N.C. Division of Air Quality determined that fly ash from a coal-fired power plant's particulate collection infrastructure as well as fly ash received from coal ash landfills or ponds is a non-hazardous solid material (NHSM) and not a solid waste. Therefore, the STAR® system will not be subject to 40 CFR 60 Subpart CCCC "Standards of Performance for Commercial and Industrial Solid Waste Incineration Units: or Subpart DDDD "Emissions Guidelines and Compliance Times for Commercial and Industrial Solid Waste Incineration Units" – commonly known as CISWI when processing fly ash.
Aug. 2, 2016	Air Permit No. 103786T32 issued to incorporate new ammonia injection rates for each turbine's Selective Catalytic Reduction (SCR) NOx control device based on recent performance testing and for administrative changes.
Aug. 26, 2016	Air Permit No. 103786T33 issued for the renewal of the Title IV acid rain program permit and the Title V permit and for the processing of the second step of the two-part significant modification for the emergency generators.

Jan. 19, 2017	Air Permit No. 103786T34 was issued as an administrative amendment to correct typographical errors and the oxidation catalyst 4-hour rolling average inlet temperature at which CO and VOCs will be considered "uncontrolled" in the Title V permit.
Feb 16, 2017	Permit Applicability Determination No. 2994 deemed that the new 55 kW diesel engine is an insignificant activity.
Apr. 24, 2017	Permit application No. 8000004.17B was received for state-only 501(c)(2) modification to add a fly ash processing facility.
May 19, 2017	Duke Energy was asked to revise its air modeling using the 2012-2016 data for the Charlotte International Airport surface station and the Greensboro Airport upper air station.
May 31, 2017	Duke Energy was requested to model emissions from the proposed project (STAR® system, crusher engine and screener engine) to demonstrate compliance with the primary 1-hour NO2 and SO2 NAAQS to demonstrate that the emissions decreases used in the PSD netting exercise are creditable.
Jun 2, 2017	During a telephone conversation with Duke Energy and in follow-up emails dated June 6, 2017, William Willets, Permit Section Chief and Tom Anderson, Permits Supervisor, established the guidelines for conducting the NO_2 and SO_2 1-hour NAAQS modeling analysis as follows: • The property boundary will serve as the "model fence line". • Emission sources for the NO_2 and SO_2 1-hour analysis should include appropriate existing permitted emission sources plus proposed emission sources that emit NO_2 and SO_2. Additional nearby sources will not be included in the analysis. • Modeled impacts will be based on NO_2 1-hour: 98th percentile, high 8th high and SO_2 1-hour: 99th percentile, high 4th high • A representative ambient background concentration for each pollutant will be added to the modeled impact of each pollutant for comparison to the appropriate NAAQS.
Jun. 6, 2017	Zoning consistency determination was received.
Jun. 15, 2017	Duke Energy was sent a letting requesting that it provide the following information related to the proposed fly ash processing facility: • A Compliance Assurance Monitoring (CAM) plan for the SO_2 emissions, • Reasonable Assurance Control Technology (RACT) for the NOx emissions, and • A revised PSD netting demonstration excluding emissions decreases that are outside of the seven-year contemporaneous period.
Jul. 6, 2017	Duke Energy was asked to provide an explanation of how it intends to comply with the acceptable ambient level for chromium VI (soluble chromate).
Jul. 13, 2017	The CAM plan and RACT analysis were received. DAQ had incorrectly added the soluble chromate emissions. The actual soluble chromate emissions are 100% of the modeled emission rate.
Jul. 24, 2017	Duke Energy was asked to specify the applicable emissions standard in 40 CFR §60.4204 for each proposed engine and provide details on the number of liters per cylinder displaced and the maximum engine speed.
Sep. 7, 2017	Telephone conversation including William Willets and Jenny Kelvington, DAQ and Dan Markley, Duke Energy to discuss PSD netting.

Sep. 12, 2017	Follow-up email sent from Jenny Kelvington to Dan Markley confirmed that 02D .0530 (b)(2) sets the "reasonable period" specified in the definition of "net emissions increase" in 40 CFR 51.166(b)(3)(ii) as seven years. Increases and decreases in actual emissions are contemporaneous if they occur no more than seven years prior to the date that the increase in emissions from the project (i.e. STAR fly ash processing facility) occurs. Increases and decreases in actual emissions shall be determined as provided in the definition of baseline actual emissions in paragraph (b)(47) of 40 CFR 51.166, except that paragraphs (b)(47)(i)(*c*) and (b)(47)(ii)(*d*) do not apply. For example, to determine the decreases in emissions from Units 3, 4, 5 and/or 6, you can use the average rate, in tons per year, at which the unit emitted the pollutant during any consecutive 24-month period within the 5-year period immediately preceding its retirement. It is my understanding that should you choose to include emissions decreases from Units 3 and 4 in the netting analysis, the permit will require the fly ash processing facility to be placed in operation on or before May 15, 2018. The netting analysis must exclude any decrease that has been relied on in obtaining an air quality permit and any retired unit for which environmental compliance cost recovery has been sought pursuant to N.C.G.S. 62-133.6.
Sep.13, 2017	Jenny Kelvington requested that Duke Energy provide the following information: 1. A list of all emission factors and the source each factor. 2. A sample calculation showing how emissions from the STAR system were estimated. 3. A table comparing the projected actual emissions from the project to the PSD significant emissions rates and identifying if netting is required. Table 3-1 of Section 3.0 includes most of this information but does not list lead. *This is step 1 of the major modification analysis.* 4. A revised PSD netting analysis.
Nov. 6, 2017	The application was reassigned to Kevin Godwin.
Nov. 17, 2017	A Draft was provided to Mooresville Regional Office.
Feb. 19, 2018	A Final Draft was provided to Supervisor.

4. Statement of Compliance

Mr. Joseph Foutz, Mooresville Regional Office (MRO) inspected the Buck Combined Cycle Plant on January 17, 2017 and concluded that the facility was in compliance with state and federal air quality requirements during the time of inspection. During the past five years, the facility has experience one compliance issue. A Notice of Violation was issued on September 10, 2013 for a continuous emissions monitor (CEM) down-time and malfunction. The down-time and malfunction did not result in an emissions violation.

5. Permit Modifications

Facility Expansion

Duke Energy Carolinas seeks a permit to construct and operate new emission sources and control devices to process fly ash that is a byproduct of coal power plants into a commercial product that can be added to Portland cement in concrete mixes to improve workability, increase durability and lower permeability.

The proposed project involves installation of the following components:

Fugitive Emission Sources

Fly Ash Truck Unloading Options

- Wet Ash Receiving - Transfer of fly ash to storage shed at a rate up to 70 short tons per hour (tph) and then transfer to the feed hopper by a front-end loader.
- Wet Ash Receiving – Transfer of fly ash to the feed hopper at a rate up to 70 tph.
- Wet Ash Receiving – Transfer to a 0.03-acre unloading storage pile and then transfer to the storage shed by a front-end loader.

Other Fugitive Fly Ash Sources

- 67-Acre Ash Basin
- Ash Handling up to 49.1 tph
- Haul Roads.

Point Source Emission Units

- Crusher, powered by a 300 Hp diesel engine and designed to remove larger particles from up to 7 tph of feedstock.
- Screener, powered by a 91 Hp diesel engine and designed to produce up to 165 tph of more fine free flowing feedstock suitable for the STAR® reactor
- Two external heat exchangers with a combined total operation not to exceed 8,760 hours per year drying a maximum of 70 tons per hour of fly ash suspended in transport air. Each exchanger will be controlled by a felted filter baghouse.
- Ash feed silo with bin vent capture devices; filled pneumatically at a rate of 125 tons per hour (tph) and unloaded at the rate of 75 tph. An induced/negative draft bin vent will control particulate emissions.
- STAR® (Staged Turbulent Air Reactor) system with a 140 million Btu/hour total maximum firing rate, processing feedstock (fly ash and other ingredient materials) into a variety of commercial products and equipped with natural gas/propane low-NOx start-up burners (60 million Btu/hour total capacity) for use during start-up or when necessary to maintain the desired reactor temperature; an integral cyclone and baghouse for product recovery; and a dry FGD scrubber and bagfilter for emissions control.
- FGD byproduct silo storing the byproduct solids from the dry FGD system discharged from the fabric filter baghouse. Silo specifications are to be determined (TBD). Material will be unloaded from the silo via gravity into trucks. An induced/negative draft bin vent will control particulate emissions.
- FGD absorbent silo storing absorbent (hydrated lime) used in the dry FGD system and equipped with an induced/negative draft bin vent for particulate control. Silo specifications are TBD.
- Transfer silo equipped with a bin vent capture devices; filled pneumatically at a rate of 125 tph and unloaded at the rate of 75 tph. An induced/negative draft bin vent will control particulate emissions
- Two loadout silo chutes, each equipped with a bin vent capture device and unloaded at a rate of 100 tph

The following table describes the changes to the current permit as requested by the application.

Page*	Section	Description of Changes
Throughout	Throughout	• Updated permit application numbers • Updated dates
4	Table of Permitted Sources	• Included STAR® (Staged Turbulent Air Reactor) system (ID No. ES-74) and associated equipment.
5	Table of Permitted Sources	• Included screener engine (ID No. ES-82B) and crusher engine (ID No. ES-83B).
21	2.1 D.	• Included screener engine (ID No. ES-82B) and crusher engine (ID No. ES-83B).
28 and 32	2.1 F. and G.	• Included STAR® (Staged Turbulent Air Reactor) system (ID No. ES-74) and associated equipment.
35	2.2 A.1.	• Updated condition pertaining to 15A NCAC 02D .1100 based on most recently approved modeling.
40	3	• Updated General Conditions to most recent shell version (version 5.1, 08/03/2017).

6. Emissions

The STAR® system will be a source of nitrogen oxides (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter (PM/PM10/PM2.5), sulfur dioxide (SO_2), hazardous air pollutants (HAPs), toxic air pollutants (TAPs) and greenhouse gases (GHGs). These compounds will be released into the environment through a 140-foot stack. Emissions result from the burning of natural gas or propane during startup and the oxidation of the residual carbon and other constituents in the fly ash. Additionally, particulate matter and toxic/hazardous metals will be emitted during the handling of the fly ash and fly ash product.

Carbon Monoxide (CO) and Volatile Organic Compounds (VOCs)- CO and VOCs will be emitted primarily from the STAR® system due to the incomplete oxidation of the carbon in the fly ash and natural gas. Complete combustion depends upon oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Turbulence within the reactor ensures thorough mixing of air (oxygen) and fuel for the desired oxidation to proceed. The crusher and screener diesel engines will also emit CO and VOCs because of the incomplete combustion.

Nitrogen Oxides (NOx) - NO_x will be emitted from the STAR® system as the result of oxidation of the nitrogen in the fly ash and auxiliary fuel. Thermal NOx is not expected to contribute significantly to emissions because its formation begins at flame temperatures above 1,200°C and the STAR® system will operate at much lower temperatures. Low NOx burners will minimize NO_x emissions associated with the auxiliary fuel. The three permitted STAR® systems (two in South Carolina and one in Maryland) have NO_x limits ranging from 0.05 to 0.34 pounds per mmBtu. 2016 stack tests of the STAR® unit at the Santee Cooper Winyah Generating Station show NO_x emissions ranging from 0.05 to 0.08 pounds per mmBtu. Duke Energy expects to emit from the STAR® system no more than 0.12 pounds of NO_x per mmBtu. Additionally, NO_x will be emitted from the crusher and screener engines.

Particulate Matter (PM) - Particulate emissions consist of filterable and condensable PM emissions resulting from ash, trace quantities of noncombustible metals, and unburned carbon due to incomplete combustion and the handling of the fly ash and the product. A baghouse will reduce PM emissions from the STAR® system to approximately 0.01 grain per actual cubic foot (acf). The induced draft fan moving the product transfer is rated at 56,846 acf per minute.

Sulfur Dioxide (SO_2) -SO_2 will form because of the oxidation of the sulfur in the fly ash and diesel fuel burned in the engines. The fly ash is expected to contain 0.25 percent sulfur on average and the diesel fuel will be limited to no more than 0.0015 percent sulfur. SO_2 formed within he STAR® system will be controlled by a dry scrubber that is designed to reduce SO_2 emissions by 95 percent.

Carbon Dioxide (CO_2) - Carbon dioxide will be the primary GHG and is a product of the complete oxidation of the carbon in the fly ash, natural gas and diesel fuel.

Toxic Air Pollutants (TAPs)/Hazardous Air Pollutants (HAPs) - TAP and HAP emissions will result primarily from fly ash combustion and handling but also from natural gas and diesel combustion. The most abundant TAPs that will be emitted include sulfuric acid mist, formaldehyde, and toluene. The HAP with the most emissions will be formaldehyde. Approximately 4 tons of formaldehyde are expected to be emitted each year.

Emission Factors – Duke Energy has relied on its fly ash analysis and on information provided by the SEFA Group Inc. to estimate emissions from the STAR® system. It also used the EPA AP-42 Compilation of Air Emission Factors where available to calculate emissions as detailed in the following table.

Source of Emissions Factors: AP-42 Chapter	Emission Source(s)
1.1 Bituminous and Subbituminous Coal Combustion	FGD byproduct silo (ES-75) FGD absorbent silo (ES-76) EHE heat exchangers (ES-77 & ES-78)
1.4 Natural Gas Combustion	Low NOx burners firing natural gas during the STAR® system startup (ES-74)
1.5 Liquefied Petroleum Gas Combustion	Low NOx burners firing propane during the STAR® system startup (ES-74)
3.3 Gasoline & Diesel Industrial Engines	Screener engine (ES-82B) Crusher engine (ES-83B)
13.2-2 Unpaved Roads	Haul roads (F-6)
13.2-4 Aggregate Handling and Storage Piles	Wet ash receiving (F-1 and F-2) Transfer of material to hopper (F-2) Ash handing operations (F-5)
13.2-5 Industrial Wind Erosion	Ash basin (F-4)

GHG emissions are based on the loss of ignition and emission factors from Table C-1 of 40 CFR Part 98.

Potential Emissions - The applicant has calculated the maximum emissions based on STAR® system operating continuously at a design rate of 140 mmBtu per hour and the auxiliary burners operating continuously at the design rate of 60 mmBtu per hour. Except for NOx, the higher of the two maximum emission rates is used as the annual potential emissions of each pollutant. To determine worst case NO_x emissions, the applicant added the maximum emissions resulting from the fly ash to the maximum emissions from the auxiliary fuel burners.

Pollutant	Potential STAR® System Emissions *Fly Ash – As Controlled*			Potential STAR® System Emissions *Auxiliary Fuels (nat. gas/propane)*			Potential as Controlled
	lb/mmBtu	lb/hour	ton/year	lb/mmBtu	lb/hour	ton/year	tons/year
CO	0.16	22.4	91.1	0.08	4.97	21.78	91.1
NOx	0.12	16.8	73.6	0.14	8.62	37.75	112.3

Pollutant	Potential STAR® System Emissions *Fly Ash – As Controlled*			Potential STAR® System Emissions *Auxiliary Fuels (nat. gas/propane)*			Potential as Controlled
	lb/mmBtu	lb/hour	ton/year	lb/mmBtu	lb/hour	ton/year	tons/year
PM	0.03	4.87	21.3	0.008	0.46	2.03	21.3
PM10	0.03	4.48	19.6	0.008	0.46	2.03	19.6
PM2.5	0.02	2.58	11.3	0.008	0.46	2.03	11.3
SO2	0.29	40.3	163.6	0.0007	0.04	0.15	163.6
VOC	0.016	2.24	9.1	0.01	0.66	2.90	9.1
Lead	127 ppmw	0.00062	0.0027		0.00003	0.0001	0.003
GHGs as CO2e	190	26,660	116,406	117	7,020	30,748	116,406

Potential emissions from all sources associated with the fly ash processing facility are listed below:

Pollutant	STAR® System (tpy)	Diesel Engines (tpy)	Ash/Product Handling and Fugitives (tpy)	Total (tpy)
CO	91.1	1.16	--	92.3
NOx	112.3	5.36	--	117.7
PM	21.3	0.38	27.4	49.1
PM10	19.6	0.38	23.6	43.6
PM2.5	11.3	0.38	12.9	24.6
SO2	163.6	0.36	--	164.0
VOC	9.1	0.43	--	9.5
Lead	0.003	--	0.003	0.006
Sulfuric acid mist	0.44	--	--	0.44
GHGs as CO2e	116,406	198	--	116,604

7. Regulatory Evaluation

The Buck Combined Cycle Plant is currently subject to the following regulations:

15A NCAC 02D .0503	Particulates from Fuel Burning Indirect Heat Exchangers
15A NCAC 02D .0515	Particulates from Miscellaneous Industrial Processes
15A NCAC 02D .0516	Sulfur Dioxide Emissions from Combustion Sources
15A NCAC 02D .0521	Control of Visible Emissions
15A NCAC 02D .0524	New Source Performance Standards, 40 CFR 60 Dc, IIII, KKKK
15A NCAC 02D .0530 (u)	Use of projected actual emissions to avoid applicability of PSD requirements
15A NCAC 02D .1100	Control of Toxic Air Pollutants
15A NCAC 02D .1111	National Emissions Standards for Hazardous Air Pollutants, 40 CFR 63 ZZZZ
15A NCAC 02D .1407(b)	Boilers and Indirect-Fired Process Heaters Annual Tune-Up
15A NCAC 02D .1418	Reasonable Available Control Technology
15A NCAC 02Q .0317	Avoidance of 02D .0501(c): Compliance with Emission Control Standards
15A NCAC 02Q .0317	Avoidance of 02D .0530: Prevention of Significant Deterioration (PSD)
15A NCAC 02Q .0402	Acid Rain Permitting Requirements, 40 CFR Part 72
15A NCAC 02Q .0711	Emission Rates Requiring a Permit
40 CFR Part 97	Cross State Air Pollution Rule, Subparts AAAAA, BBBBB and CCCCC

The regulations applicable to the proposed fly ash processing facility include:

15A NCAC 02D .0515	Particulates from Miscellaneous Industrial Processes
15A NCAC 02D .0516	Sulfur Dioxide Emissions from Combustion Sources
15A NCAC 02D .0521	Control of Visible Emissions
15A NCAC 02D .0524	New Source Performance Standards, 40 CFR 60 IIII
15A NCAC 02D .0540	Particulates from Fugitive Dust Emission Sources
15A NCAC 02D .1100	Control of Toxic Air Pollutants
15A NCAC 02D .1111	National Emissions Standards for Hazardous Air Pollutants, 40 CFR 63 ZZZZ
15A NCAC 02D .1413	[Nitrogen Oxide] Sources Not Otherwise Listed in This Section [02D .1400]
15A NCAC 02Q .0711	Emission Rates Requiring a Permit

The applicability of New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP) and Prevention of Significant Deterioration (PSD) are addressed in Section 8 of this review. Air Toxics (02D .1100 and 02Q .0711) compliance is discussed in Section 9.

15A NCAC 02D .0515, Particulates from Miscellaneous Industrial Processes[3]

This regulation limits particulate emissions from any stack, vent, or outlet, resulting from any industrial process, for which no other emission control standard is applicable, in proportion to the process rate using one of the following equation.

For process rates of no more than 30 tons per hour: $\mathbf{E = 4.10 \times P^{0.67}}$

For process rates of more than 30 tons per hour: $\mathbf{E = 55.0 \times P^{0.11} - 40}$

Where: E = allowable emission rate in pounds per hour (lbs/hr) and P = process rate in tons per hour (tons/hr).

The table below shows the process rate, allowable PM emission rate and potential pre-control and post-control filterable PM emissions rate for each propose emission source subject to this rule.

Emission Source	ES ID No.	Process Rate (tph)	Allowable PM (lb/hr)	Potential PM before control (lb/hr)	Potential PM after control (lb/hr)	Compliance Expected?
Feed silo filling	73A	125	53.5	N/A	<0.01	Yes
Feed silo unloading	73B	75	48.4	N/A	<0.01	Yes
STAR® reactor	74	75	48.4	4.87	4.87	Yes
FGD byproduct silo	75	TBD	TBD	TBD	0.06	Yes
FGD absorbent silo	76	TBD	TBD	TBD	0.06	Yes
EHE (Units 1/2)	77/78	70	47.8	N/A	5.36	Yes
Storage dome filling	80A	75	48.4	N/A	<0.01	Yes
Storage dome unloading	80B	275	62.0	N/A	0.01	Yes
Transfer silo filling	79A	175	53.5	N/A	<0.01	Yes
Transfer silo unloading	79B	75	48.4	N/A	<0.01	Yes
Loadout silo	81	75	48.4	N/A	<0.01	Yes
Loadout chute (1A/1B)	81A/B	100	51.3	N/A	<0.01	Yes

Emission Source	ES ID No.	Process Rate (tph)	Allowable PM (lb/hr)	Potential PM before control (lb/hr)	Potential PM after control (lb/hr)	Compliance Expected?
Screener	82A	165	56.4	4.13[4]	0.36	Yes
Crusher	83A	7	15.1	N/A	<0.01	Yes

Compliance with this standard is expected for all emissions sources without the use of a particulate emissions control device. Therefore, no monitoring, recordkeeping or reporting will be required in the 02D .0515 permit condition.

15A NCAC 02D .0516, Sulfur Dioxide Emissions from Combustion Sources

This regulation limits the emissions of sulfur dioxide (SO_2) from combustion sources that discharge through a vent, stack, or chimney to no more than 2.3 pounds of SO_2 per million Btu heat input. A source subject to a SO_2 emission standard in 02D .0524, .0527, 01110, .1111, .1205, .1206, .1210 or .1211 of 15A NCAC shall meet the standard in that particular rule rather the 02D .0516 SO_2 limit. The diesel engines for the crusher and screener are subject to a SO_2 standard in 02D .0524 and thus not subject to this rule. For this modification, 02D .0516 applies only to the STAR® system, which is equipped with a dry FGD scrubber for SO_2 emissions control.

The STAR® system is initially fueled by natural gas/propane and then becomes self-sustained by burning fly ash. SO_2 forms when the sulfur contained in the fuel and fly ash is oxidized during combustion. When only natural/propane is fired in the STAR® reactor, compliance is achieved without emissions control. When the STAR® reactor is fueled by fly ash, the associated scrubber is required to reduce SO_2 emissions by at least 60 percent to achieve compliance. As designed, the scrubber is expected to reduce the amount of SO_2 in the flue gas by 95 percent. Therefore, compliance with this rule is expected with emissions control. The 02D .0516 permit condition will require monitoring of the scrubber to ensure compliance is achieved.

STAR® System Fuel	Maximum Sulfur Content	Heat Input Rate (mmBtu/hr)	Potential SO2 before control (lb/mmBtu)	Potential SO2 after control (lb/mmBtu)	Compliance?
Fly ash	0.25 % by weight	140	5.75	0.29	Yes
Natural gas/propane low-NOx burners	0.6 lbs/million cubic feet[5]	60	<0.001	<0.001	Yes

15A NCAC 02D .0521, Control of Visible Emissions

This rule applies to fuel burning sources and other sources that may have visible emissions, if the source is not subject to a visible emission standard in 02D .0506, .0508, .0524, .0543, .0544, .1110, .1111, .1205, .1206, .1210, or .1211. Visible emissions from sources manufactured after July 1, 1971 are limited to no more than 20 percent opacity when averaged over a six-minute period, except as specified in 15A NCAC 02D .0521(d) by this regulation. All proposed sources associated with the fly ash processing facility will be subject to the 20 percent opacity limit for sources manufactured after July 1, 1971. Each point source

[4] Based on AP-42 Table 11.19.2-2 "Crushed Stone Screening (uncontrolled) (SCC 3-05-020-02,03)

[5] AP-42 Table 1.4-2 (rev. 07/98)

that could potentially have significant visible emissions is provided with particulate emissions control. Compliance with this standard is expected using the proposed emissions control equipment.

15A NCAC 02D .0540, Particulates from Fugitive Dust Emission Sources

This rule requires that owners and operators not cause or allow fugitive dust emissions to cause or contribute to substantive complaints or excess visible emissions beyond the property boundary. The applicant has identified six sources of fugitive dust emissions associated with the proposed fly ash processing facility. Compliance is expected.

ID No.	Fugitive Emission Source	Size	PM Emissions (lb/hr)	Comments
F-1	Wet Ash Receiving – Transfer to Shed	185' x 120'	0.0025	Wet ash has a low fugitive dust emissions potential.
F-2	Wet Ash Receiving – Transfer to Hopper	36' x 70'	0.0051	
F-3	Wet Ash Receiving – Unloading Pile	13' x 45'	0.0049	
F-4	Ash Basin	67 acres	0.507	Strong winds will kick up dust but are not expected to cause excessive dust offsite.
F-5	Ash Handling	n/a	0.086	Not expected to cause excessive dust offsite.
F-6	Haul Roads	n/a	0.165	Trucks will kick up dust when transporting some ash to an offsite location but are not expected to cause excessive dust offsite.

15A NCAC 02D .1400, Control of Nitrogen Oxides

This section applies to the existing Buck Combined Cycle plant because it is a facility with potential emissions of NO_x equal to or greater than 100 tons per year or 560 pounds per calendar day beginning May 1 through September 30 of any year in the Rowan County. The 02D .1400 rules establish control requirements for specific NO_x emission sources and sources not otherwise listed that have the potential to emit 100 tons per year or more of nitrogen oxides or 560 pounds per calendar day or more from May 1 through September 30 except as noted in 02D .1402(h). A "source" means a stationary boiler, combustion turbine, combined cycle system, reciprocating internal combustion engine, indirect-fired process heater or a stationary article, machine, process equipment, or other contrivance, or combination thereof, from which nitrogen oxides emanate or are emitted.

02D .1413 in this Section applies to the proposed STAR® reactor as it is a major source of NO_x (greater than 100 tons per year) located in Rowan County. It requires the STAR® reactor to be equipped with reasonably available control technology (RACT) for NO_x abatement. The other proposed sources with NO_x emissions – i.e., the two diesel engines - are exempted from the 02D .1400 rules due to their size.

Control options considered for the STAR® reactor include selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), staging of air or water injection.

Selective reduction can achieve NO_2 control efficiencies ranging from 80 to 90 percent. When NO_2 reacts with ammonia or urea at high temperatures it is reduced to elemental nitrogen (N_2) and water (H_2O). This reduction reaction requires that a SNCR be operated at a temperature of 1600 ^{O}F or more. A SCR can be operated at lower temperatures – typically between 480 ^{O}F and 800 ^{O}F - because it contains a catalyst bed that serves to lower the activation energy required for the NO_2 reduction reaction to proceed. However, the maximum design temperature of the baghouse collecting the fly ash product is only 350 ^{O}F and locating a SCR or SNCR prior to the baghouse would cause the unit to not function properly. The exhaust stream contains 100% of the product ash. Due to the risk of product contamination, both SCR and SNCR are not considered to be technically feasible. No STAR® reactor in operation has SCR or SNCR control.

Staging of air and water injection into the primary combustion zone reduce thermal NO_x formation by lowering the peak temperature in the reactor and decreasing the residence time. Both NO_x reduction techniques are inherent to the STAR® reactor design and considered to be technically feasible. Air and water are ingredients added to the reactor to create the final ash product.

Duke Energy has proposed a combination of air staging and water injection as the reasonably achievable methods for controlling NO_x emissions and a NO_x emissions limit for the STAR® reactor at 0.12 pounds per million Btu. The proposed limit is sufficiently protective as it is much less than the 02D .1407 NO_x limits established for boilers and indirect process heaters as shown below.

MAXIMUM ALLOWABLE NO_X EMISSION RATES FOR BOILERS AND INDIRECT PROCESS HEATERS
(POUNDS PER MILLION BTU)

	Firing Method		
Fuel/Boiler Type	Tangential	Wall	Stoker or Other
Coal (Wet Bottom)	1.0	1.0	N/A
Coal (Dry Bottom)	0.45	0.50	0.40
Wood or Refuse	0.20	0.30	0.20
Oil	0.30	0.30	0.30
Gas	0.20	0.20	0.20

NC DAQ finds the proposed RACT with the use of staging of air and water injection and a 0.12 pounds NO_x per mmBtu satisfies the requirements for RACT in 02D .1413.

Duke Energy will be required to conduct an initial performance test within six months of the proposed STAR® reactor being placed into operation and perform subsequent testing once every five years. Compliance is expected.

8. NSPS, NESHAP/MACT, NSR/PSD, 112(r), CAM

15A NCAC 02D .0524, New Source Performance Standards

The existing facility is subject to the following New Source Performance Standards (NSPS):

1. NSPS Subpart Dc, "Industrial Boilers and Indirect Process Heaters"
2. NSPS Subpart IIII, "Stationary Compression Ignition Internal Combustion Engines"
3. NSPS Subpart KKKK, "Stationary Combustion Turbines"

The NSPS conditions possibly applicable to the fly ash facility include:
1. NSPS Subpart CCCC, "Commercial and Industrial Solid Waste Incineration Units"
2. NSPS Subpart IIII, "Stationary Compression Ignition Internal Combustion Engines"

40 CFR 60 Subpart CCCC -This rule establishes standards of performance for commercial and industrial solid waste incineration units (CISWI). In June 2015, N.C. DAQ made a determination that the STAR® reactor would not be subject to CISWI. The fly ash from a coal-fired power plant's particulate collection infrastructure and well as fly ash received from coal ash landfills or ponds when used as an ingredient product in the reactor – in accordance with 40 CFR 241 .3(b)(4) –is considered a non-hazardous secondary material (NHSM) and not a solid waste.

40 CFR 60 Subpart IIII, "Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE)"- This rule establishes standards of performance for diesel-fired stationary compression engines built after 2004. It requires that Duke Energy purchase diesel-fired engines for the crusher and screener that have been certified by the manufacturer as meeting the applicable emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable. The engines will be a 2007 model year or later non-emergency stationary CI ICE engine with a maximum engine power less than or equal to 2,237 kilowatts (3,000 horsepower) and a displacement of less than 10 liters per cylinder.

Furthermore, Duke Energy must operate the proposed engines per the manufacturer's instructions, burn only low-sulfur fuel with no more than 0.0015 percent sulfur, and install an hour meter on each engine. Duke Energy has consistently met these requirements for the existing engines subject to Subpart IIII and thus, it is expected to comply with all applicable emission limitations, monitoring, recordkeeping and reporting for the new engines.

15A NCAC 02D .1111, National Emissions Standards for Hazardous Air Pollutants (NESHAP)
The Buck Combined Cycle Facility is a minor source of hazardous air pollutants (HAPs) and potential emissions (after controls and limitations) will remain less than 10 tons per year for the largest HAP and less than 25 tons per year for total HAPs when the proposed fly ash processing facility comes online. Minor sources of HAPs are only subject to NESHAPs that apply to area sources.

NESHAP – 40 CFR Part 63, Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines (RICE) applies to the existing fire pump engine, the existing emergency generator and the proposed diesel engines. As per 40 CFR Part 63.6590(c), an affected source that meets the requirements of NSPS Subpart IIII for compression ignition engines satisfies the requirements of Subpart ZZZZ. Compliance is expected.

15A NCAC 02D .0530 Prevention of Significant Deterioration (PSD)/New Source Review (NSR)
Under Prevention of Significant Deterioration (PSD) requirements, all major new or modified stationary sources of air pollutants as defined in Section 169 of the Federal Clean Air Act (CAA) must be reviewed and permitted prior to construction by EPA or permitting authority, as applicable, in accordance with Section 165 of CAA. A *major stationary source* is defined as any one of 28 named source categories, which emits or has a potential to emit (PTE) 100 tons per year of any regulated pollutant, or any other stationary source, which emits or has the potential to emit 250 tons per year of any PSD regulated pollutant.

The facility is an existing major source with respect to PSD and located in Rowan County, which is part of the Charlotte-Gastonia-Rock Hill, NC-SC; 1997 Ozone Attainment/Maintenance area. It has been classified as one of the 28 named source categories under the category of "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input." It emits or has the potential to emit 100 tons per year of the following regulated pollutants: PM10, SO_2, NO_x, and CO.

For existing major stationary sources, there are several conditions that must be meet for a modification to be deemed a *major modification* and therefore subject to PSD pre-construction review. There must be:

1. a physical change or change in the method of operation;
2. a net emissions increase of a PSD regulated pollutant; and
3. the net emissions increase must be equal to or more than applicable "significance level" listed in 40 CFR 51.166(b)(23)(i).

Constructing the STAR® fly ash processing facility is a physical change and its operation will emit several regulated pollutants at rates more than the PSD significance emissions rate (SER) as shown in the table below:

Pollutant	Emissions (tons/yr)	SER (tons/yr)	Netting Required?
PM	49.1	25	Yes
PM10	43.6	15	Yes
PM2.5	24.6	10	Yes
SO_2	164.0	40	Yes
NOx	117.7	40	Yes
CO	92.3	100	No
VOC	9.5	40	No
Lead	0.006	0.6	No
CO2 equiv.	116,604	75,000	Yes
H_2SO_4 mist	0.44	7	No

The next step is to determine if the **"net"** increases in PM/PM10/PM2.5, SO_2, NO_x, and CO_2(e) emissions at the site are significant. 40 CFR 51.166(b)(3) defines a "net emissions increase" to be, the sum of the increases associated with the project plus the contemporaneous increases and decreases. All emissions from the existing combined cycle gas turbines (ID Nos. ES-11 and ES-12) and associated emission sources are considered contemporaneous increases.

For a decrease in emissions to be considered credible, it must:
1. occur "*within a reasonable period*" – North Carolina specifies seven years;
2. be one for which N.C. DAQ *"has not relied on it in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs;"*
3. be "*enforceable as a practical matter at and after the time that actual construction on the particular change begins;*" and (4) have "*approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.*"

On February 27, 2013, Duke Energy filed Application No. 8000004.13A requesting that the following retired combustion sources be removed from its permit:

- Three coal-fired electric utility boilers (ID Nos. ES-1 to ES-3)) *retired 5-14-2011*
- Three simple-cycle combustion turbines (ID Nos. ES-6 to ES8) *retired 10-1-2012*
- Two coal-fired electric utility boilers (ID Nos. ES-4 (B8) and ES-5 (B9)) and one auxiliary boiler (ID No. ES-9) *retired 4-1-2013*

For the netting exercise, Duke Energy included the average emissions for the calendar years 2010 and 2011 baseline period from two coal-fired boilers (ID Nos. ES-4 and ES-5) as contemporaneous decreases. These boilers were retired on April 1, 2013 – less than seven years prior to the date that the fly ash processing facility is expected to begin operations. The 24-month baseline emissions selected is consistent with the definition of "baseline actual emissions" in 15A NCAC 2D .0530(b)(1) which states it is "*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 5-year period immediately preceding the date the application is received by the Division…*" Baseline emissions must also be representative of normal source operation. Only one consecutive 24-month period can be used to determine baseline emissions for each pollutant for all the emission sources being changed; however, a different consecutive 24-month period can be used for each pollutant.

Pollutant	2010-2011 Average (TPY)		
	ES-4 (B8)	ES-5 (B9)	Total
CO	367.06	349.96	717.02
NOX	376.80	404.90	781.70
PM(TSP)	151.76	138.58	290.34
PM10	134.31	126.69	261.00
PM2.5	114.24	106.72	220.96
SO2	2,382.65	2,341.80	4,724.45

Rule 15A NCAC 2D .0530(b)(1)(A)(iv) states that for an electric utility steam generating unit, the baseline emission rate shall be adjusted downward to reflect any emissions reductions under General Statue 143-215.107D. This legislation, known as the "Clean Smokestacks Act," was passed into law by the General Assembly of North Carolina in 2001 to improve air quality in the State by imposing limits on SO_2 and NO_x emissions from Duke Energy and Progress Energy facilities. Thus, the portion of the baseline emissions that were part of the reductions required under the Clean Smokestacks Act must be reduced from the actual emissions. Because the shutdown of the two coal-fired boilers was not required to comply with the Clean Smokestacks Act, no adjustment is necessary.

As demonstrated in the following table extracted from the application, the net emissions increase in CO_2(e) emissions are significant under PSD. However, per 15A NCAC 02D .0544 (a), a PSD permit in not required when only the increase in greenhouse gases emissions is significant – which is the case for the proposed fly ash processing facility. Additionally, because Duke Energy used potential emissions to demonstration that PSD does not apply to this modification, no 15A NCAC 02D .0530 (u) emissions monitoring and reporting condition is required.

It is important to note that even without the emissions control provided by the FGD scrubber, the net increase in SO_2 emissions are insignificant.

Table 3-3. PSD Netting Analysis

Description of Emission	NO_x (TPY)	SO_2 (TPY)	PM (TPY)	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	CO_{2e} (TPY)
Proposed Project Emission (Increases)	117.66	163.98	49.14	43.59	24.64	116,604
PSD Avoidance CAP for ES11 and ES12 (Increases)	599.8	108.52	198.90	160.8	160.8	2,669,078
ES13 – 10 cell cooling tower (Increases)			7.00	7.00	7.00	
ES14 – Auxiliary Boiler (Increases)	1.80	0.22	0.40	0.40	0.40	
ES15 – Fuel oil fired emergency generator (Increases)	0.80	0.0009	0.028	0.023	0.023	
ES16 – Fuel oil fired fire water pump (Increases)	0.10	0.0001	0.004	0.004	0.004	
ES72 – Chiller cooling tower (Increases)			0.60	0.60	0.60	
Ash basin water management pump (Increases)	2.50	0.004	0.016	0.016	0.016	
ES17 – Fuel oil fired emergency generator, 762 hp (Increases)	0.513	0.0005	0.003	0.002	0.002	
Total Increases	723.17	272.73	256.09	212.43	193.48	2,785,682
Contemporaneous Decreases	(781.70)	(4724.45)	(290.26)	(257.94)	(220.84)	(0)
Difference	-58.53	-4451.72	-34.17	-45.50	-27.35	2,785,682
PSD SERS	40	40	25	15	10	75,000
Significant Modification	No	No	No	No	No	Yes

Source: ECT, 2017.

Duke Energy modeled emissions from the proposed project (STAR® system, crusher engine and screener engine) to demonstrate compliance with the primary 1-hour NO2 and SO2 NAAQS to demonstrate that the emissions decreases used in the PSD netting exercise are creditable. The modeling exercise was reviewed by Mr. Matthew Porter, Meteorologist II, Air Quality Analysis Branch (AQAB). According to Mr. Porter's modeling analysis review memo dated February 5, 2018, the 1-hour NO2 and SO2 modeling demonstrates facility-wide impacts will not cause or contribute to a violation of the NAAQS.

112(r)

Per Form A3 entitled "112(r) Applicability Information", the facility is not subject to 40 CFR Part 68 "Prevention of Accidental Releases" – Section 112(r) of the Federal Clean Air Act. The facility is not subject to this rule because it does not store one or more of the regulated substances in quantities above the thresholds in the Rule. This permit modification does not affect the 112(r) status.

Compliance Assurance Monitoring (CAM)

The CAM rule (40 CFR 64; 15A NCAC 02D .0614) applies to each pollutant specific emissions unit (PSEU) at major TV facilities that meets all three following criteria:

1. Is subject to an emission limitation or standard, and
2. Uses a control device to achieve compliance, and
3. Has potential pre-control emissions that exceed or are equivalent to the major source threshold.

However, if the source is subject to an emission limitations or standards for which a permit issued under 15A NCAC 02Q .0500 that specifies a continuous compliance determination method, as defined in 40 CFR 64.1, it is exempt from CAM.

The STAR® system is subject to 02D .0516, is vented to a dry FGD scrubber to comply with this rule, and its potential pre-control SO_2 emissions are 3,272 tons per year – which is more than the 100 tons per year major source threshold. Therefore, CAM applies.

Duke Energy has prepared a CAM plan for the dry FGD scrubber which calls for continuous monitoring of the lime to sulfur ratio to ensure that the scrubber reduces SO_2 emissions from the STAR® system to no more than 2.3 pounds per million Btu of heat input (lb/mmBtu). Duke Energy will conduct initial performance tests for three operating scenarios - processing fly ash with a high sulfur content, a mid-range sulfur content and a low sulfur content - to derive a relationship between the lime to sulfur ratio and SO_2 emissions. These results will then be used to establish a minimum lime to sulfur ratio for each operating scenario that will provide reasonable assurance that SO_2 emissions will not exceed the 2.3 lb/mmBtu limit.

The minimum lime to sulfur ratio will apply when the STAR® system is operating except during periods of startup, shutdown or malfunction. During normal operations, any three-hour rolling period that the lime to sulfur ratio falls below the minimum established value will be considered an excursion. Each excursion must be investigated to determine the monitoring status and/or operating conditions responsible for the excursion and the appropriate corrective measures to reduce the potential for its reoccurrence. These measures will be implemented as needed to restore the lime to sulfur ratio to the appropriate range. Duke Energy will report all excursions in its semi-annual report and include the number, duration and cause of excursions and the corrective measures taken.

The proposed CAM plan provides a reasonable assurance of compliance with 02D .0516. When functioning as designed, the FGD scrubber should reduce SO_2 emissions to 0.29 lb/mmBtu and thus provide 8 times more emissions reduction than the minimum required.

9. Facility Wide Air Toxics

The facility is subject to 02Q .0711 and 02D .1100. The proposed fly ash processing facility will emit nine toxic air pollutants (TAPs) with facility wide emissions rates more than the NC Toxic Pollutant Emission Rates (TPERs) listed in 02Q .0711.

The applicant has performed modeling following the requirements outlined in 40 CFR 51, Appendix W, Guidelines on Air Quality Models and NC DAQ Air Toxics Quality Modeling Guidelines, February 2014. AERMOD, Version 16216r was used in the refined modeling analysis for flat, elevated and complex terrain, which demonstrated compliance with the acceptable ambient levels (AALs) for all nine TAPs with potential emissions above the TPERs. The receptors evaluated are shown in the chart below.

The modeling exercise was reviewed by Mr. Matt Porter, AQAB. According to Mr. Porter's modeling analysis review memo dated February 5, 2018, the modeling analysis of maximum-allowable facility-wide TAP emissions adequately demonstrated compliance with the Acceptable Ambient Levels (AALs) outlined in 15A NCAC 02D .1104, on a source-by-source basis, for all TAPs.

A summary of the modeled emissions rates and results are provided in the tables below. The first table shows model emissions rates in pounds per hour while the second table shows the modeled impact in microgram per cubic meter. The modeled maximum impact for each pollutant is less than the maximum allowable concentration. The maximum impact as a percent of the allowable range from 0.01 percent (mercury) to 93.5 percent (chromium VI - soluble chromate).

TABLE 8-1: Modeled Emissions Rates (lb/hr)

Source	Sulfuric Acid Mist		Benzene	Formaldehyde	As	Be	Cd	Cr VI	Hg	Ni
	1-hr	24-hr	Annual	1-hr	Annual	Annual	Annual	24-hr	24-hr	24-hr
ES-11	1.70	1.70	2.51E-2	4.46E-1	5.11E-4	3.08E-5	2.81E-3	1.43E-4	4.11E-4	5.38E-3
ES-12	1.70	1.70	2.51E-2	4.46E-1	5.11E-4	3.08E-5	2.81E-3	1.43E-4	4.11E-4	5.38E-3
ES-14			2.34E-5	3.68E-3	2.24E-6	1.35E-7	1.23E-5	6.27E-7	1.27E-5	1.03E-4
ES-73					5.27E-7	1.09E-7	9.41E-8	1.54E-7	7.40E-9	1.40E-6
ES-74	0.10	0.10	1.24E-4	4.41E-3	5.89E-4	1.20E-4	1.68E-4	7.71E-5	1.90E-5	8.25E-4
ES-77					6.35E-4	1.32E-4	1.13E-4	8.48E-5	4.07E-6	7.71E-4
ES-78					6.35E-4	1.32E-4	1.13E-4	8.48E-5	4.07E-6	7.71E-4
ES-79					5.27E-7	1.09E-7	9.41E-8	1.54E-7	7.40E-9	1.40E-6
ES-80					5.27E-7	1.09E-7	9.41E-8	2.70E-7	1.30E-8	2.45E-6
ES-81					2.63E-7	5.46E-8	4.70E-8	5.78E-8	2.78E-9	5.26E-7
ES-81A					1.32E-7	2.74E-8	2.35E-8	7.71E-8	3.70E-9	7.01E-7
ES-81B					1.32E-7	2.74E-8	2.35E-8	7.71E-8	3.70E-9	7.01E-
F-1					1.96E-7	4.06E-8	3.52E-8	4.02E-8	1.94E-9	3.66E-7
F-2					3.93E-7	8.13E-8	7.01E-8	8.04E-8	3.86E-9	7.31E-7
F-3					5.28E-7	1.20E-7	1.04E-7	7.76E-8	3.73E-9	7.06E-7
F-4					7.08E-5	1.47E-5	1.26E-5	9.76E-6	4.68E-7	8.87E-5
Total Modeled	**3.5**	**3.5**	**5.03E-2**	**9.00E-1**	**2.96E-3**	**4.61E-4**	**6.04E-3**	**5.44E-4**	**8.62E-4**	**1.33E-2**
Form D1 Expected Ave. Emissions (EAE)	**3.5**		**5.06E-2**	**9.06E-1**	**2.33E-3**	**3.29E-4**	**5.91E-3**	**5.11E-4**	**9.11E-4**	**1.26E-2**
EAE as a % of Modeled Rate	**100%**		**100%**	**100%**	**79%**	**71%**	**98%**	**94%**	**100%**	**95%**

TABLE 8-2: Modeled Impacts (microgram/m^3)

Modeled Year	Sulfuric Acid Mist		Benzene	Formaldehyde	As	Be	Cd	Cr VI	Hg	Ni
	1-hr	24-hr	Annual	1-hr	Annual	Annual	Annual	24-hr	24-hr	24-hr
2012	0.66	0.17	2.5E-4	0.17	3.8E-4	8.0E-5	9.0E-5	5.3E-4	5.0E-5	4.92E-3
2013	0.65	0.18	1.7E-4	0.17	3.7E-4	8.0E-5	8.0E-5	4.9E-4	5.0E-5	4.53E-3
2014	0.68	0.19	2.2E-4	0.18	4.0E-4	8.0E-5	9.0E-5	5.6E-4	5.0E-5	5.17E-3
2015	0.92	0.47	1.7E-4	0.25	4.5E-4	9.0E-5	1.0E-4	5.8E-4	1.3E-4	5.5E-3
2016	0.71	0.20	2.5E-4	0.19	3.7E-4	8.0E-5	9.0E-5	5.6E-4	5.0E-5	5.14E-3
Allowable	100	12.0	0.12	150	2.1E-3	4.1E-3	5.5E-3	6.2E-4	0.60	0.60
Max. as % of Allowable	1.4%	2.5%	0.2%	0.2%	11.2%	5.4%	2.0%	93.5%	0.01%	0.9%

The TAP emission limit table in permit condition 2.2.A.1 has been updated as follows to reflect the modeled emission rates and the new TAP emission sources.

Emission Source	Toxic Air Pollutant	Emission Limit(s)
Turbines (ID Nos. ES-11 and ES-12) (emission limit per turbine)	Acrolein	0.0127 lb/hr
	Arsenic	4.48 lb/yr
	Benzene	220 lb/yr
	Benzo(a)pyrene	6.39E-03 lb/yr
	Beryllium	0.27 lb/yr
	Cadmium	24.6 lb/yr
	Chromium VI (Soluble Chromate)	3.43E-03 lb/day
	Formaldehyde	0.446 lb/hr
	Non-specific Chromium VI Compounds, as Chromium VI Equivalent	1.25 lb/yr
	Manganese	0.0233 lb/day
	Mercury	9.86E-03 lb/day
	Nickel Metal	0.129 lb/day
	Sulfuric Acid Mist	1.70 lb/hr
Cooling Tower (ID No. ES-13)	Chlorine	2.25E-04 lb/hr
		0.054 lb/day
Boiler (ID No. ES-14)	Arsenic	0.0196 lb/yr
	Benzene	0.206 lb/yr
	Benzo(a)pyrene	0.000118 lb/yr
	Beryllium	0.00118 lb/yr
	Cadmium	0.108 lb/yr
	Chromium VI (Soluble Chromate)	1.5E-05 lb/day
	Formaldehyde	0.00368 lb/hr
	Non-specific Chromium VI Compounds, as Chromium VI Equivalent	0.00549 lb/yr
	Manganese	0.000447 lb/day
	Mercury	3.05E-04 lb/day
	Nickel Metal	0.00247 lb/day
Emergency Engine (ID No. ES-15)	Arsenic	4.76E-05 lb/yr
	Benzene	9.21E-03 lb/yr
	Beryllium	3.57E-05 lb/yr
	Cadmium	3.57E-05 lb/yr
	Chrome VI (Soluble Chromate)	3.13E-05 lb/day
	Formaldehyde	8.25E-04 lb/hr
	Mercury	3.13E-05 lb/day

Emission Source	Toxic Air Pollutant	Emission Limit(s)
	Nickel Metal	3.13E-05 lb/day
Fire Water Pump (ID No. ES-16)	Arsenic	7.57E-06 lb/yr
	Benzene	1.77E-03 lb/yr
	Beryllium	5.68E-06 lb/yr
	Cadmium	5.68E-06 lb/yr
	Chromium VI (Soluble Chromate)	4.98E-06 lb/day
	Formaldehyde	1.96E-03 lb/hr
	Mercury	4.98E-06 lb/day
	Nickel Metal	4.98E-06 lb/day
Emergency Engine (ID No. ES-17)	Arsenic	2.44E-05 lb/yr
	Benzene	4.72E-03 lb/yr
	Beryllium	1.83E-05 lb/yr
	Cadmium	1.83E-05 lb/yr
	Chromium VI (Soluble Chromate)	1.60E-05 lb/day
	Formaldehyde	4.21E-04 lb/hr
	Mercury	1.60E-05 lb/day
	Nickel Metal	1.60E-05 lb/day
Chiller Cooling Tower (ID No. ES-72)	Chlorine	2.5E-04 lb/hr
		0.006 lb/day
Feed Silo Filling and Unloading (ID No. ES-73A/73B) (Total)	Arsenic	4.62E-03 lb/yr
	Beryllium	9.56E-04 lb/yr
	Cadmium	8.24E-04 lb/yr
	Chromium VI (Soluble Chromate)	3.70E-06 lb/day
	Mercury	1.78E-07 lb/day
	Nickel Metal	3.36E-05 lb/day
STAR® Reactor (ID No. ES-74)	Arsenic	5.16 lb/yr
	Benzene	1.08 lb/yr
	Beryllium	1.05 lb/yr
	Cadmium	1.47 lb/yr
	Chromium VI (Soluble Chromate)	1.85E-03 lb/day
	Formaldehyde	4.41E-03 lb/hr
	Mercury	4.56E-04 lb/day
	Nickel Metal	0.0198 lb/day
	Sulfuric Acid Mist	0.1 lb/hr
External Heat Exchangers (ID Nos. ES-77 and ES-78) (emission limit per heat exchanger)	Arsenic	5.56 lb/yr
	Beryllium	1.16 lb/yr
	Cadmium	0.99 lb/yr
	Chromium VI (Soluble Chromate)	2.04E-03 lb/day
	Mercury	9.77E-05 lb/day
	Nickel Metal	0.0185 lb/day
Transfer Silo Filling and Unloading (ID No. ES-79A/B) (Total)	Arsenic	4.62E-03 lb/yr
	Beryllium	9.56E-04 lb/yr
	Cadmium	8.24E-04 lb/yr
	Chromium VI (Soluble Chromate)	3.70E-06 lb/day
	Mercury	1.78E-07 lb/day
	Nickel Metal	3.36E-05 lb/day
Storage Dome Filling and Unloading (ID No. ES-80A/B) (Total)	Arsenic	4.62E-03 lb/yr
	Beryllium	9.56E-04 lb/yr
	Cadmium	8.24E-04 lb/yr
	Chromium VI (Soluble Chromate)	6.48E-06 lb/day

Emission Source	Toxic Air Pollutant	Emission Limit(s)
	Mercury	3.12E-07 lb/day
	Nickel Metal	5.89E-05 lb/day
Loadout Silo (ID No. ES-81)	Arsenic	2.31E-03 lb/yr
	Beryllium	4.78E-04 lb/yr
	Cadmium	4.12E-04 lb/yr
	Chromium VI (Soluble Chromate)	1.39E-06 lb/day
	Mercury	6.67E-08 lb/day
	Nickel Metal	1.26E-05 lb/day
Loadout Silo Chutes (ID No. ES-81A/B) (Emissions limit per chute)	Arsenic	1.15E-03 lb/yr
	Beryllium	2.40E-04 lb/yr
	Cadmium	2.06E-04 lb/yr
	Chromium VI (Soluble Chromate)	1.85E-06 lb/day
	Mercury	8.88E-08 lb/day
	Nickel Metal	1.68E-05 lb/day
Screener Engine (ID No. ES-82B)	Arsenic	0.002 lb/yr
	Benzene	0.457 lb/yr
	Beryllium	1.50E-03 lb/yr
	Cadmium	1.50E-03 lb/yr
	Chromium VI (Soluble Chromate)	1.52E-05 lb/day
	Formaldehyde	7.52E-04 lb/hr
	Mercury	1.52E-05 lb/day
	Nickel Metal	1.52E-05 lb/day
Crusher Engine (ID No. ES-83B)	Arsenic	1.00E-04 lb/yr
	Benzene	0.029 lb/yr
	Beryllium	1.00E-04 lb/yr
	Cadmium	1.00E-04 lb/yr
	Chromium VI (Soluble Chromate)	6.30E-06 lb/day
	Formaldehyde	2.48E-03 lb/hr
	Mercury	6.30E-05 lb/day
	Nickel Metal	6.30E-05 lb/day
Wet Ash Receiving – Transfer to Shed (F-1)	Arsenic	1.72E-03 lb/yr
	Beryllium	3.56E-04 lb/yr
	Cadmium	3.08E-04 lb/yr
	Chromium VI (Soluble Chromate)	9.65E-07 lb/day
	Mercury	4.66E-08 lb/day
	Nickel Metal	8.78E-06 lb/day
Wet Ash Receiving – Transfer to Hopper (F-2)	Arsenic	3.44E-03 lb/yr
	Beryllium	7.12E-04 lb/yr
	Cadmium	6.14E-04 lb/yr
	Chromium VI (Soluble Chromate)	1.93E-06 lb/day
	Mercury	9.26E-08 lb/day
	Nickel Metal	1.75E-05 lb/day
Wet Ash Receiving – Unloading Pile (F-3)	Arsenic	5.09E-03 lb/yr
	Beryllium	1.05E-03 lb/yr
	Cadmium	9.10E-04 lb/yr
	Chromium VI (Soluble Chromate)	1.86E-06 lb/day
	Mercury	8.95E-08 lb/day
	Nickel Metal	1.69E-05 lb/day

Emission Source	Toxic Air Pollutant	Emission Limit(s)
Ash Basin (F-4)	Arsenic	0.620 lb/yr
	Beryllium	0.129 lb/yr
	Cadmium	0.110 lb/yr
	Chromium VI (Soluble Chromate)	2.25E-04 lb/day
	Mercury	1.08E-05 lb/day
	Nickel Metal	2.05E-03 lb/day

10. Facility Emissions Review

The project and facility-wide emissions following the modification are shown in the table below.

CRITERIA AIR POLLUTANT EMISSIONS INFORMATION AFTER CONTROLS/LIMITATIONS (Tons per Year)				
AIR POLLUTANT EMITTED	PROPOSED STAR® FACILITY		FACILITY-WIDE (After Project)	
	POTENTIAL EMISSIONS AS CONTROLLED/ LIMITED (Tons/Year)	EXPECTED ACTUAL EMISSIONS* (Tons/Year)	POTENTIAL EMISSIONS AS CONTROLLED/ LIMITED (Tons/Year)	EXPECTED ACTUAL EMISSIONS* (Tons/Year)
PARTICULATE MATTER (PM)	49.14	49.14	256.09	256.09
PARTICULATE MATTER < 10 MICRONS (PM10)	43.59	43.59	212.43	212.43
PARTICULATE MATTER < 2.5 MICRONS (PM2.5)	24.64	24.64	193.48	193.48
SULFUR DIOXIDE (SO2)	163.98	163.98	272.73	272.73
NITROGEN OXIDES (NOx)	117.66	117.66	723.17	723.17
CARBON MONOXIDE (CO)	95.26	95.26	246.47	246.47
VOLATILE ORGANIC COMPOUNDS (VOC)	9.54	9.54	55.70	55.70
CO2 Equivalent (CO2e)	116,604	116,604	2,785,682	2,785,682
TOTAL HAZARDOUS AIR POLLUTANTS (HAPS)	0.53	0.53	7.83	7.83
LARGEST HAP (FORMALDEHYDE)	0.02	0.02	3.97	3.97

11. Public Notice/EPA and Affected State(s) Review

The public, the EPA, the Mecklenburg County Local Program, and other interested parties will have an opportunity to review and make comments on the draft permit. A public notice of the draft permit and review will be published in XXXX and posted to the DAQ website on XXXXX.

According to NCGS 130A-309.203(b) a public hearing is required as follows:

> (b) Notwithstanding G.S. 130A-295.8(e), the Department shall determine whether an application for any permit necessary to conduct activities required by this Part is complete within 30 days after the Department receives the application for the permit. A determination of completeness means that the application includes all required components but does not mean that the required components provide all of the information that is required for the Department to make a decision on the application. If the Department determines that an application is not complete, the Department shall notify the applicant of the components needed to complete the application. An applicant may submit additional information to the Department to cure the deficiencies in the

application. The Department shall make a final determination as to whether the application is complete within the later of (i) 30 days after the Department receives the application for the permit less the number of days that the applicant uses to provide the additional information or (ii) 10 days after the Department receives the additional information from the applicant. The Department shall issue a draft permit decision on an application for a permit within 90 days after the Department determines that the application is complete. The Department shall hold a public hearing and accept written comment on the draft permit decision for a period of not less than 30 or more than 60 days after the Department issues a draft permit decision. The Department shall issue a final permit decision on an application for a permit within 60 days after the comment period on the draft permit decision closes.

12. Other Regulatory Considerations

- Mr. Thomas Pritcher, P.E. License No. 025453 sealed the original application and revision 1, pursuant to 15A NCAC 02Q .0112, on April 17, 2017 and November X, 2017. A search of the registrant directory on the N.C. Board of Examiners for Engineers and Surveyors website confirmed that Mr. Pritchard is licensed to practice engineering in the state.
- The application includes a zoning consistency determinations signed by Ed Muire, Planning and Development Director for Rowan County. Mr. Muire noted that the STAR® plant is preempted from local zoning authority pursuant to HB630/State Law 2016-95.

13. Comments and Recommendations

This permit application has been reviewed by DAQ to determine compliance with all procedures and requirements. DAQ has determined that this facility is expected to achieve compliance as specified in the permit with all applicable requirements. Mr. Jim Hafner of the Mooresville Regional Office (MRO) was provided a draft on November 17, 2017. Mr. Hafner responded with minor comments. All comments were addressed. Mr. Dan Markley, Duke Energy, was provided a draft on November 17, 2017. Mr. Markley responded with comments on December 1, 2017. All comments were addressed. The Division will make a recommendation regarding permit issuance following a public hearing. A summary of the public hearing is provided in Attachment I.

ATTACHMENT I: Public Hearing Summary

Time:
Date:
Location:

Comments: