NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date: TBD

Region: Mooresville Regional Office
County: Rowan
NC Facility ID: 8000004
Inspector's Name: Jim Vanwormer
Date of Last Inspection: 11/20/2020
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: .0503, .0515, .0516, .0521, .0524, .0540, .1100, .1111, .1407, .1413, .1418
02Q: .0317, .0400, .0711
NSPS: 40 CFR Part 60, Subparts Dc, IIII, KKKK
NESHAP: 40 CFR Part 63, Subpart ZZZZ
PSD: Major
PSD Avoidance: 02Q .0317
NC Toxics: 02D .1100, 02Q .0711
112(r): n/a
Other: Cross State Air Pollution Rule

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Dale Wooten Environmental Coordinator (704) 630-3086 1385 Dukeville Road Salisbury, NC 28146	Kristopher Eisenrieth General Manager (704) 630-3015 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: 8000004.20A, .20B, 21A
Date Received: 01/27/2021
Application Type: Renewal/Modification
Application Schedule: TV-Renewal

Existing Permit Data

Existing Permit Number: 03786/T36
Existing Permit Issue Date: 04/03/2020
Existing Permit Expiration Date: 07/31/2021

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2019	9.10	130.13	8.30	14.03	50.08	2.00	0.9580 [Hexane, n-]
2018	10.90	156.38	9.70	16.45	58.41	2.37	1.13 [Hexane, n-]
2017	10.60	150.67	9.52	16.13	57.39	2.32	1.11 [Hexane, n-]
2016	10.40	147.41	9.27	15.72	56.10	2.25	1.08 [Hexane, n-]
2015	10.60	147.07	9.42	15.73	67.12	2.26	1.08 [Hexane, n-]

Review Engineer: Russell Braswell

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

Comments / Recommendations:
Issue 03786/T37
Permit Issue Date: TBD
Permit Expiration Date: TBD+5 years

1. Purpose of Applications:

1. <u>8000004.21A (received January 27, 2021)</u>

   Duke Energy Carolinas, LLC - Buck Combined Cycle Facility (DEC; the facility) currently operates a power plant in Rowan County under Title V permit 03786T36 (the existing permit). The existing permit expired on July 31, 2021. Therefore, as required by General Condition K of the existing permit, DEC has submitted application .21A in order to renew the Title V permit. Because the renewal application was received at least six months before the expiration date, the existing permit will remain in effect, regardless of expiration date, until the renewed permit is issued.

   In addition to renewing the Title V permit, DEC has submitted this application in order to comply with the application submittal requirement in Specific Condition 2.2 B.2.a of the existing permit. DEC was required to submit this application because the Staged Turbulent Air Reactor (STAR®) sources were added to the permit as part of a 2-step significant modification as allowed by 15A NCAC 02Q .0501(b)(2). In the application, DEC states that there have been no changes to the STAR® sources since first step of the significant modification was implemented in the T36 revision of the permit. DEC's requirements under 15A NCAC 02Q .0501(b)(2), 15A NCAC 02Q .0504, and Specific Condition 2.2 B.2.a of the existing permit are discussed in Section 5.1 below.

   DEC also requested the following changes to the existing permit:

   - Make several revisions to the list of insignificant activities. These changes are listed in Section 5.2 below.

   - Allow the use of non-hazardous fire retardants in the STAR® system. This change is discussed in Section 5.5 below.

2. <u>8000004.20A (October 21, 2020)</u>

   The existing permit includes a reference to the facility's Title IV permit (a.k.a. the acid rain permit). The acid rain permit is set to expire at the same time as the Title V permit. Therefore, DEC has submitted application .20A in order to renew the acid rain permit. In this application, DEC specifically requested that the Title IV and Title V permits be renewed at the same time to allow for an easier renewal process in the future.

3. <u>8000004.20B (December 21, 2020)</u>

   The existing permit includes Specific Condition 2.2 B.1.l, which requires DEC to perform initial compliance testing on the STAR® system. In addition, the existing permit includes Specific Condition 2.2 B.1.t, which requires DEC to submit a permit application to incorporate the results of the aforementioned emission testing into the permit. DEC has submitted application .20B in order to comply with this requirement. This change is discussed in Section 5.3 below.

2. Facility Description:

This facility is a power plant that produces electricity for sale to the grid. The facility consists of two combined-cycle natural gas-fired combustion turbines and two heat recovery steam generators (HRSG; one per turbine). Each combustion turbine powers a generator, and the hot exhaust from the turbines is directed into the associated HRSG. The HRSG is supplemented with heat from a natural gas-fired duct burner (one per HRSG), and the steam from the HRSGs is used to generate electricity in a single steam-cycle turbine.

Nominal generating capacity of the entire system is 620 megawatts.[1] Each combustion turbine is equipped with low-NOx burners, selective catalytic reduction (SCR), and oxidation catalyst.

In addition, DEC operates a flyash processing facility (the Staged Turbulent Air Reactor, or STAR® facility). The STAR® facility takes flyash from coal combustion and processes it into a product that meets the definition ASTM Standard 618-08 and has a capacity of 400,000 tons per year.[2] Heat for this process comes from natural gas-fired burners and residual carbon within the flyash. Emissions from the reactor are controlled by a flue gas desulfurization (FGD) scrubber and a baghouse.

The facility also includes several activities that support the above activities, such as emergency-use generators, flyash silos, conveyors, and miscellaneous storage tanks.

This facility formerly operated several coal-fired electric utility boilers. These boilers have been decommissioned and removed from the permit as of the T31 permit revision (issued Feb 23, 2015). The only power generation activities at this facility are combined-cycle turbines mentioned above.

3. Title V Permit Modifications Following the Previous Permit Renewal:

- August 26, 2016 — Permit T33 issued. This action renewed the Title V and Title IV permits and completed a 2-step significant modification for the addition of emergency generators to the facility.
- January 30, 2017 — Permit T34 issued. This action was an administrative amendment to correct typos in the T33 permit revision.
- May 10, 2018 — Permit T35 issued. This action was the 1st step of a 2-step significant modification. This modification added the STAR® system and associated sources to the permit.
- April 3, 2020 — Permit T36 issued. This action was the 1st step of a 2-step significant modification. This modification added additional sources and revise existing sources associated with the STAR® system.

4. Application Chronology:

- October 21, 2020 — Application .20A received (Title IV renewal).
- December 21, 2020 — Application .20B received (administrative amendment).
- January 27, 2021 — Application .21A received (Title V renewal with modification).
- March 8, 2021 — An initial draft of the permit and this application review were sent to RCO staff.
- April 7, 2021 — A draft of the permit and this application review were sent to MRO staff and DEC staff.

[1] See page 2 of the application review for the T22 permit revision (issued October 15, 2008).
[2] See page 2 of the application review for the T35 permit revision (issued May 10, 2018).

- May 18, 2021 — DEC amended the Title V renewal application to include the addition of fire-retardant additives in the STAR® process.
- May 19, 2021 — A request for additional information was sent to Dan Markley requesting additional information regarding the fire-retardant additives.
- June 8, 2021 — Response received to the May 19 request.
- June 10, 2021 — A request for additional information was sent to Dan Markley requesting an updated NHSM determination.
- July 27, 2021 — Response received to the June 10 request.
- September 15, 2021 — A request for additional information was sent to Dan Markley requesting the model year of the NSPS-affected engines at this facility.
- October 7, 2021 — Response received to the September 15 request.
- December 16, 2021 — Email sent to DEC regarding corrections for the permit. These issues included: removing monitoring, recordkeeping, and reporting for control devices that are considered integral, adding monitoring, recordkeeping, and reporting for the bagfilter associated with the STAR®, including the use of water injection in the STAR® as a control device on the list of permitted emission sources, and potentially requiring monitoring for water injection in the STAR®.
- February 4, 2022 — Email sent to DEC regarding potentially requiring a CAM plan for water injection in the STAR®.
- February 16, 2022 — After additional discussion, the issues raised by the December 16 and February 4 emails were resolved. DEC submitted information showing that water injection in the STAR® is integral to the system and therefore not a control device for CAM purposes.
- March 3, 2022 — A new draft of the permit and application review, reflecting the above updates and DAQ's new Title V permit format, were sent to DEC staff.
- XXXX — The Public Notice and EPA review periods began.
- XXXX — The Public Notice period ended.
- XXXX — The EPA Review period ended.
- XXXX — Permit issued.

5. Changes to the Existing Permit:

1. 2-Step Significant Modification under 15A NCAC 02Q .0501(b)(2)

   Per 15A NCAC 02Q .0501(b)(2), DAQ allows in some circumstances applicants to apply for a significant modification to a Title V permit using a 2-step process. The second step of this process requires the applicant to submit a new application for permit modification within 12 months of commencing operation of the modified facility.

On April 24, 2017, DEC submitted application .17B in order to add the STAR® process to the Title V permit. This application was the first step of a 2-step significant modification as allowed by 15A NCAC 02Q .0501(b)(2). As a result, DAQ issued the T35 permit revision on May 10, 2018. This permit included Section 2.2 B.2.a, which required DEC to submit a second application within 12 months of the commencement of operation of the STAR® sources.

After the T35 permit was issued, but before the STAR® process began operating, DEC submitted application .19A in order to update and change various emission sources associated with the STAR® process. This action added additional silos and ash handling systems, removed a crusher, increased the ash basin size, corrected projected emissions and $PM_{2.5}$ emission factors, and added an SO_2 CEMS to the STAR® process (thus removing the need for a CAM plan for the STAR®, see Section 6.16.iii below for a discussion of CAM applicability).

DAQ also processed application .19A as the first step of a 2-step significant modification and issued the T36 permit. This permit revised Section 2.2 B.2.a to include the sources added and modified with the .19A application. which required DEC to submit a second application within 12 months of the commencement of operation of the STAR® sources.

On January 27, 2021, DEC submitted application .21A in order to satisfy the 2nd step requirement in Section 2.2 B.2.a of the existing permit. According to the cover letter to the .21A application, the 12-month deadline for submitting this application would have been April 3, 2021. In addition, DEC stated that "there are no changes to the permitted equipment or emission profiles based on [application .19A]." The .21A application satisfies the 2-step significant modification requirements for both applications .17B and .19A.

The new permit will not include any substantial changes with regards to the STAR® process. For ease of review, DAQ's reviews of applications .17B and .19A are included in this document as Attachment 1 and Attachment 2, respectively. The conclusions reached by those previous reviews have not changed.

The requirement to submit this application was required by 15A NCAC 02Q .0504 and included in the existing permit as Specific Condition 2.2 B.2. This condition and references to 02Q .0504 will be removed from the permit.

2. <u>Changes to Insignificant Activities</u>

DEC included several corrections to the list of Insignificant Activities in the existing permit:

- Revise the descriptions of I-11, I-79, I-85, and I-107;
- Remove I-12, I-24, I-25, I-67, and I-71;
- Add the sources in Table 1:

Table 1: Proposed Additions to Insignificant Activities

Emission Source ID No.	Emission Source Description
I-108	Gasoline storage tank (300 gallons maximum capacity)
I-109	Diesel storage tank (264 gallons maximum capacity) for the ash basin dewatering pump (ES-86)

Emission Source ID No.	Emission Source Description
I-110	Diesel storage tank in the #1 ash pond area (2,000 gallons maximum capacity)
I-111	Diesel storage tank in Ash Beneficiation area (1,000 gallons maximum capacity)
I-112	Laboratory chemical vent hood
I-113	Two spare transformers (602 gallons maximum capacity each, of mineral oil)
I-114	Various small (less than 500 gallon capacity each) mineral oil-filled transformers throughout the site

Emissions from small diesel and mineral oil tanks are expected to be negligible due to the low vapor pressure of those materials. Emissions from the small gasoline storage tank are expected to be less than five tons per year due to the small size of the tank. Emissions from laboratory vent hoods are expected to be negligible due to the small scale of laboratory work at this facility. Therefore, DAQ agrees that these sources should be added to the list of insignificant activities.

These changes are not expected to have an impact on potential or actual emissions from the facility or change DEC's compliance requirements.

3. Emission factor update

The existing permit includes Section 2.2 B.1.l, which requires DEC to perform initial compliance testing on the STAR® process. In addition, the existing permit includes Section 2.2 B.1.t, which requires DEC to submit a permit application to incorporate the test results into the equation in Section 2.2 B.1.p.

DEC completed the initial compliance testing on October 16, 2020 (test reference number 2020-163ST), and submitted application .20B in order to comply with Section 2.2 B.1.t.

The initial compliance testing showed a post-control emission rate of 0.126 pounds of PM per ton of ash processed in ES-74. The equation in Section 2.2 B.1.p will be updated with this emission factor. Additionally, the equation will be reformatted slightly for clarity:

PM emissions, ton/month = [(coal ash processed in ES-74, ton/month) × (0.126 pound/ton) +
(total hours of operation for ES-77 and ES-78, hour/month) × (6.86 pound/hour) +
(hours of operation for ES-84, hour/month) × (0.78 pound/hour)] / (2,000 pound/ton) +
(0.41 ton/month)*

* This is the default total emission rate for STAR® facility ancillary sources (ID Nos. ES-73, ES-75, ES-76, ES-79, ES-80, ES-81, ES-81A, ES-81B, ES-82A1, ES-82A2, ES-82B1, ES-82B2, ES-82C1 through ES-82C6, ES-82D1 through ES-82D6, ES-85, ES-86, and ES-F1 through ES-F6)

The requirement to perform initial compliance testing for the STAR® process will be removed from the new permit. Note that the new permit will still require subsequent compliance testing on a five-year schedule.

4. Use of Projected Actual Emissions (02D .0530(u))

A facility may choose to demonstrate the non-applicability of Prevention of Significant Deterioration (PSD) by calculating the change in emissions from a proposed modification using the "projected actual emissions" method described in paragraph (u) of 15A NCAC 02D .0530. In general, the facility must compare projected post-construction actual emissions to the pre-construction actual emissions to ensure that a PSD review would not be required. The facility must then calculate and report the annual emissions from the modification for five years following the completion of the modification. The facility has no further requirements after the reporting period ends.

The existing permit includes a specific condition for 02D .0530(u) because DEC used projected actual emissions to show the T30 modification (issued September 23, 2014) did not trigger PSD applicability. DEC fully implemented the modification in 2014, and the permit required DEC to report emissions for the next five years (i.e., until 2020). The reporting requirement was included in the existing permit as Specific Condition 2.1 A.4.

Now that the reporting period for this modification has ended, DEC has no requirements under this rule. This condition and references to 02D .0530(u) will be removed from the permit.

5. Use of non-hazardous fire retardants in the STAR® system.

According to an addendum to the renewal application, DEC has had issues with fires in the STAR® system (specifically the external heat exchangers). The addendum states: "In order to alleviate this situation, [DEC is] proposing to add material to the feedstock ash to improve the fluidization of the ash (to eliminate hot spots as the flyash clumps) and to add a level of fire resistance to the flyash. These potential additives will not contain any toxic chemicals and will not affect [DEC's] emissions."

A footnote will be added to the list of permitted emission sources stating that the use of emissions-neutral flyash additives (such as flame retardants) may be used in the STAR® system.

The flyash used in the STAR® system has previously been determined to be a non-hazardous secondary material (NHSM). This determination was initially made without consideration for additives. As part of the request to include fire retardant additives, DEC submitted an updated NHSM determination. Based on this information, it appears the flyash will still qualify as an NHSM.

Furthermore, it appears that the proposed additives do not contain any hazardous air pollutants or solids, and will not increase actual emissions from the STAR® system. See Attachment 3 additional information.

6. Summary of Changes

The following table summarizes the changes made to the existing permit:

Page No.*	Section*	Description of Changes
Throughout	Throughout	• Updated dates and permit numbers. • Fixed formatting. • Corrected typos.

* This refers to the current permit unless otherwise stated.

6. Regulatory Overview and Rules Review:

Under the existing permit, DEC is subject to the following State Implementation Plan (SIP) rules:

1. 15A NCAC 02D .0503 "Particulates from Fuel Burning Indirect Heat Exchangers"
2. 15A NCAC 02D .0515 "Particulates from Miscellaneous Industrial Processes"

3. 15A NCAC 02D .0516 "Sulfur Dioxide Emissions from Combustion Sources"
4. 15A NCAC 02D .0521 "Control of Visible Emissions"
5. 15A NCAC 02D .0524 "New Source Performance Standards" (40 CFR Part 60, Subparts Dc, IIII, and KKKK)
6. 15A NCAC 02D .0540 "Particulates from Fugitive Non-Process Dust Emission Sources"
7. 15A NCAC 02D .1100 "Control of Toxic Air Pollutants"
8. 15A NCAC 02D .1111 "Maximum Achievable Control Technology" (40 CFR Part 63, Subpart ZZZZ)
9. 15A NCAC 02D .1407 "Boilers and Indirect-Fired Process Heaters"
10. 15A NCAC 02D .1413 "Sources Not Otherwise Listed"
11. 15A NCAC 02D .1418 "New Electric Generating Units, Large Boilers, and Large I/C Engines"
12. 15A NCAC 02Q .0317 "Avoidance Conditions" (Avoidance of PSD, NSR, and 02D .0501(c))
13. 15A NCAC 02Q .0400 "Acid Rain Procedures"
14. 15A NCAC 02Q .0711 "Emission Rates Requiring a Permit"

In addition to the above SIP rules, DEC is also subject to the Cross State Air Pollution Rule. This rule is not included in North Carolina's SIP. DEC's requirements under each of these rules are discussed below. In addition, a discussion of several non-applicable rules is also included below.

1. <u>15A NCAC 02D .0503 "Particulates from Fuel Burning Indirect Heat Exchangers"</u>

   This rule limits particulate matter (PM) emissions from indirect heat exchangers with no other specific PM emission limits. This rule applies to the combined-cycle turbines (only when the duct burners are operating) and the auxiliary boiler (ID Nos. ES-11, 12, and 14).

   For any subject emission source at a facility, the PM limit is a function of the total heat input of sources subject to this rule at the facility. The limit is determined initially and is not revised when heat inputs and/or sources are changed thereafter. At the time these sources were added to the permit, the total heat input was 4,191 MMBtu/hr. Therefore, the PM limit was calculated as $E = 1.090 \times (4{,}191)^{-0.2594} = 0.125$ lb/MMBtu.[3] Because these sources were added to the permit at the same time, the PM limit will be the same for each source.

   The only fuel burned in the above-mentioned sources is natural gas. Based on the emission factors published in USEPA's document "Compilation of Air Emissions Factors" (a.k.a. AP-42), natural gas emissions are several orders of magnitude less than the PM limit and the turbines and auxiliary boiler are expected to comply with 02D .0503. Therefore, the permit does not require any monitoring, recordkeeping, or reporting to comply with this rule. Continued compliance is expected.

2. <u>15A NCAC 02D .0515 "Particulates from Miscellaneous Industrial Processes"</u>

   This rule limits PM emissions from emission sources that exhaust through a stack, vent, or outlet, and with no other specific PM emission limits. The emission limit is a function of the process rate of the subject emission source:

$$E = 4.10(P)^{0.67} \quad (P \leq 30)$$
$$E = 55.0(P)^{0.11} - 40 \quad (P > 30)$$

   Where:
   E is the PM limit in pounds per hour, and
   P is the process rate of the source in tons per hour.

[3] See page 14 of the application review for the T22 permit revision, issued October 15, 2008.

At this facility, the cooling towers and the emission sources associated with the STAR® process are subject to this rule.

Cooling towers: The cooling towers were originally evaluated for compliance with this rule during the T22 permit revision. At that time, the potential PM emissions from the tower were expected to be 0.6 tpy. Given the high process rate of the cooling towers (the nominal flow rate of ES-13 is 213,000 gallons per minute), compliance with the above emission limit is assumed, and continued compliance for the cooling towers is expected.

STAR® process: For the reactor portion of the STAR® process (ES-74), the permit includes no specific compliance requirements with regards to 02D .0515. This is an omission, because the STAR® uses a bagfilter to comply with this rule. The permit new permit will include maintenance, monitoring, recordkeeping, and reporting for the bagfilter.

For the other portions of the STAR® process (e.g., the silos), the permit requires DEC to operate fabric filters to control PM emissions. The existing permit requires that DEC perform regular maintenance and keep records regarding the bagfilters and bin vent filters associated with these sources. This is not appropriate, because these filters are integral to their respective sources and are therefore not control devices. Instead, as indicated in Section 1 of the existing permit, these filters are "Non-optional air pollution control equipment that constitutes an integral part of the process equipment as originally designed and manufactured by the equipment supplier." Given that filters are integral to the process, there should not be mandatory additional monitoring, recordkeeping, and reporting for these filters.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

3. <u>15A NCAC 02D 0516 "Sulfur Dioxide Emissions from Combustion Sources"</u>

This rule limits sulfur dioxide (SO_2) emissions from combustion sources for which there are no other SO_2 emission standards. In all cases, the limit is 2.3 pounds of SO_2 per million Btu of heat input. The auxiliary boiler, reciprocating internal combustion engines (RICE), and the reactor portion of the STAR® process are subject to this rule. The turbines are not subject to this rule because each is subject to an SO_2 standard under 02D .0524 (see Section 6.5.iii).

Auxiliary boiler: The only fuel used in the auxiliary boiler is natural gas. Based on the emission factors found in chapter 1.4 of AP-42, this fuel has inherently low sulfur content and is expected to comply with 02D .0516. Therefore, no monitoring, recordkeeping, or reporting is required to demonstrate compliance with this rule for the auxiliary boiler.

RICE: The only fuel used in the RICE is No. 2 fuel oil (a.k.a. diesel fuel). As part of compliance with NSPS Subpart IIII (see Section 6.5.ii), these engines can only burn diesel fuel with low sulfur content. Based on the emission factors found in AP-42 Table 3.3-1 (for small engines) and 3.4-1 (for large engines), this fuel has a maximum potential SO_2 emission rate of less than the limit discussed above. Therefore, no monitoring, recordkeeping, or reporting is required to demonstrate compliance with this rule for the RICE.

Note that the existing permit does not include a reference to this rule for the RICE. A new specific condition for this rule has been added to the permit for each RICE. However, as discussed previously, there are no monitoring, recordkeeping, or reporting requirements associated with this rule for these RICE.

STAR® process: DEC is required to control SO_2 emissions from the reactor portion of the STAR® process with a dry flue-gas desulfurization scrubber (FGD scrubber) and monitor SO_2 emissions with a continuous emission monitoring system (CEMS). In addition, DEC is required to summarize any records excess emissions on a quarterly basis and submit a report of excess emissions twice per year.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

4. <u>15A NCAC 02D 0521 "Control of Visible Emissions"</u>

This rule limits the opacity of non-fugitive visible emissions (VE) from emission sources that do not have a specific VE limit under other 02D .0500 rules. For sources constructed after 1971 (i.e., each source at this facility), the rule limits opacity in most cases to 20%. Each turbine, boiler, RICE, and source associated with the STAR® process at this facility is subject to this rule.

Turbines and boilers: In general, burning natural gas in a combustion turbine or boiler is not expected to produce VE in excess of 20% under normal operations. DAQ has historically not required any specific monitoring, recordkeeping, or reporting to demonstrate compliance with 02D .0521 for burning natural gas in turbines and boilers. Therefore, the permit does not include any specific compliance requirements for these sources and 02D .0521.

RICE: In general, burning diesel fuel in a well-maintained engine is not expected to produce VE in excess of 20% under normal operations. DAQ has historically not required any specific monitoring, recordkeeping, or reporting to demonstrate compliance with 02D .0521 for diesel fuel in engines that are also subject to NSPS Subpart IIII and/or MACT Subpart ZZZZ (see Sections 6.5.ii and 6.8, respectively). Therefore, the permit does not include any specific compliance requirements for these sources and 02D .0521.

STAR® process: In order to demonstrate compliance with VE emissions from the sources associated with the STAR® process, DEC must perform regular VE observations. If above-normal VE is detected, DEC must make appropriate corrective actions as soon as practicable. Records of VE observations must be kept and reported twice per year.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

5. <u>15A NCAC 02D .0524 "New Source Performance Standards" (NSPS; 40 CFR Part 60)</u>

This rule incorporates the NSPS rules issued under 40 CFR Part 60 into North Carolina's SIP (excluding those rules listed in 02D .0524(b)). NSPS Subparts Dc, IIII, and KKKK apply to sources at this facility. See Section 6.16 below for a discussion of rules (including NSPS rules) that do not apply to this facility.

i. <u>NSPS Subpart Dc "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units"</u>

This rule applies to boilers with a heat input between 10 and 100 million Btu per hour and were constructed after June 9, 1989. The auxiliary boiler ES-14 is subject to this rule. Note that §60.40c(e) specifically exempts heat recovery steam generators (HRSG) that are associated with turbines subject to NSPS Subpart KKKK. This facility has two HRSGs (one each for the turbines ES-11 and ES-12). The turbines ES-11 and ES-12 are subject to NSPS Subpart KKKK, and therefore the associated HRSGs are not subject to NSPS Subpart Dc.

For a boiler that only fires natural gas and has a capacity less than 30 million Btu per hour, the only requirement under this rule is for DEC to maintain records of fuel usage in the boiler on a monthly basis. DEC must submit a report of the fuel usage twice per year.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

ii. NSPS Subpart IIII "Standards of Performance for New Stationary Compression Ignition Internal Combustion Engines"

This rule applies to stationary compression ignition engines (i.e., diesel-fired engines) constructed after July 1, 2006. Of the stationary engines at this facility, ID No. I-4 was constructed before this date and is therefore not subject to this rule. The remaining engines (ID Nos. ES-15. ES-16, ES-17EmGen, ES-82B1, ES-82B2, ES-82D1, ES-82D6, and ES-86) are subject to this rule.

The emission limits of this rule differ based on the size, model year of the engine, and purpose of the engine (e.g., emergency use, fire pump, etc.). In general, each engine must be certified to meet the emission limits in 40 CFR 60.4201 based on the model year and engine size. The emission limits for each engine at this facility are summarized in Table 2:

Table 2: Summary of Emission Limits under NSPS Subpart IIII

Engine	Limit (grams per kilowatt-hour)			
	NMHC*+NOx	NOx	CO	PM
ES-16	4.0	--	3.5	0.20
ES-15 and ES-17EmGen	6.4	--	3.5	0.20
ES-82B1 and ES-82B2	--	0.40	3.5	0.02
ES-82D1 through ES-82D6 and ES-86	4.7	--	5	0.03

* Non-methane hydrocarbons

In all cases, DEC must perform regular maintenance, operate with good work practices, and operate the engines according to the manufacturer's instructions. DEC must only burn ultra-low sulfur diesel fuel in these engines. DEC must keep records of maintenance and operation and report these records twice per year.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

iii. NSPS Subpart KKKK "Standards of Performance for Stationary Combustion Turbines"

This rule applies to stationary gas turbines constructed, modified, or reconstructed after February 18, 2005. Both turbines are subject to this rule.

In general, this rule limits emissions of nitrogen oxides (NOx) and SO_2 based on the type of fuel being fired. In general, DEC demonstrates compliance with this rule by operating a NOx CEMS and records of sulfur content in the natural gas fired in the turbines. DEC must keep records of operations and emissions and submit reports semiannually. Note that although the NSPS rules generally require CEMS and excess emission calculations to be performed semiannually, DAQ requires facilities to perform these calculations on a quarterly basis instead. Therefore, the permit requires semiannual reporting but quarterly calculations for CEMS data.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

6. 15A NCAC 02D .0540 "Particulates from Fugitive Non-Process Dust Emission Sources"

This rule limits PM emissions from fugitive sources, such as haul roads and stockpiles. In general, the rule requires that facilities not cause or contribute to dust complaints outside of the property boundary.

If dust complaints are received, DEC may be required to develop and implement a fugitive dust control plan. However, no such complaints have been received against DEC.

Compliance with this rule will be determined during subsequent inspections and investigations of dust complaints (if any are received.)

7. 15A NCAC 02D .1100 "Control of Toxic Air Pollutants" [State-enforceable Only]

This rule requires facilities to emit toxic air pollutants (TAP) at rates less than what would cause an exceedance of the acceptable ambient limits (AAL) listed in 02D .1104.

This facility has previously been reviewed for TAP emissions. DEC submitted air dispersion modeling on July 2, 2019 (approved by DAQ on October 1, 2019) that showed there would be no exceedances of an AAL for any TAP emitted from the facility. Modeling was performed using emission rates that correspond to 98% of the AAL for each TAP. In each case, this "optimized" emission rate was greater than the potential emission rate for that pollutant. Therefore, no recordkeeping, monitoring, or reporting is required for DEC to demonstrate compliance with the modeled emission rates. The modeled emission rates are included in the permit as emission limits.

Note that emission sources subject to a rule under 40 CFR Part 63 (i.e., subject to a MACT) are exempt from TAP emission limits provided that there is no unacceptable risk to human health (see 15A NCAC 02Q .0702(27) and NC GS 143-215.107(a)(5)). Each reciprocating combustion engine at this facility is subject to MACT Subpart ZZZZ (discussed in Section 6.8). DAQ has previously determined that TAP emissions from these sources "…are not expected to present an unacceptable risk to human health."[4]

8. 15A NCAC 02D .1111 "Maximum Achievable Control Technology" (MACT; 40 CFR Part 63)

This rule incorporates the MACT standards under 40 CFR Part 63 into North Carolina's SIP. For the purposes of MACT applicability, this facility is an area source of hazardous air pollutants because it emits less than 10 tons per year (tpy) of any individual hazardous air pollutant (HAP) and less than 25 tpy of total combined HAP.[5] As such, rules that apply to major sources (e.g., the MACT standards for combustion turbines under 40 CFR Part 63, Subpart YYYY) do not apply to this facility.

The only MACT that applies to this facility is Subpart ZZZZ "National Emissions Standards for HAP (NESHAP) from Stationary Reciprocating Internal Combustion Engines (RICE)." This rule applies to

[4] See discussion and emission calculations on pages 17 – 21 of the application review for the T36 permit revision (issued April 3, 2020).

[5] Note that this facility was previously a major source. This facility was reclassified as an area source with the T31 permit revision (issued February 23, 2015). This was possible because DEC chose to remove five coal-fired boilers from the permit.

stationary RICE at major and area sources of HAP. Therefore, each RICE at this facility is subject to this rule.

In general, RICE that are subject to NSPS Subpart IIII (i.e., each diesel-fired engine except I-4) demonstrate compliance with Subpart ZZZZ by complying with the NSPS. The requirements of NSPS Subpart IIII are discussed in Section 6.5.ii above.

For engines not subject to an NSPS, the requirements of the rule differ based on several facts about the engine. For the purposes of this rule, the engine I-4 is considered an existing, emergency-use engine located at an area source of HAP. In general, the requirements for such sources are:

- Change oil, belts, and filters on a regular schedule;
- Operate with good work practices according to manufacturer specifications;
- Keep records of maintenance activities and hours of operation; and
- Install a non-resettable hour meter.

Note that the above requirements only apply to sources on the list of insignificant activities. Therefore, these requirements will not be included in the body of the Title V permit. DEC must still comply with these requirements.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections.

9. 15A NCAC 02D .1407 "Boilers and Indirect-Fired Process Heaters"

This rule applies to boilers located in areas described in 02D .1402. Rowan County is listed, so this rule applies to boilers at this facility. The only such source at this facility is the auxiliary boiler. The HRSGs associated with the turbines are not subject to this rule because they are subject to 02D .1418 instead.

For boilers with a heat input less than 50 million Btu per hour, the only requirement under this rule is to perform regular boiler tune-ups using the criteria in 02D .1404. DEC must maintain records of required tune-ups and maintenance and submit a summary report twice per year.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

10. 15A NCAC 02D .1413 "Sources Not Otherwise Listed"

This rule applies to emission sources that emit NOx (excluding boilers, indirect-fired process heaters, combustion turbines, and internal combustion engines) located at a facility with potential NOx emissions greater than 100 tons per year. In addition, the source must be located in an area described by 02D .1402.

The reactor portion of the STAR® process is subject to this rule. Each other source of NOx at this facility is a boiler, combustion turbine, or internal combustion engine.

This rule requires sources to submit a RACT plan that generally meets the requirements of 02D .1400. In the .17B application, DEC proposed a RACT emission limit of 0.12 pounds of NOx per million Btu of heat input, based on the use of air and water injection into the STAR®. In the application, DEC stated that “Staging of air and water injection in the STAR unit already occur since air and water are part of the ingredients added to the reactor to create the final product."[6] DAQ approved the proposed RACT with the T35 permit.

In order to demonstrate compliance with the limit, DEC must perform an initial performance test, and then a perform new test every five years.

DEC performed the initial compliance test on October 16, 2020 (test reference number 2020-163ST). The test showed a NOx emission rate of 0.07 pounds per million Btu. Continued compliance will be determined with subsequent emission testing.

11. 15A NCAC 02D .1418 "New Electric Generating Units, Large Boilers, and Large I/C Engines"

This rule applies to electric generating units installed after October 31, 2000. The turbines ES-11 and ES-12 were installed after this date, so they are subject to this rule.

This rule specifically limits NOx emissions to the more stringent of 0.15 lb/MMBtu and any applicable limit under 02D .0530. When initially constructed, these turbines were subject to 02D .0530(h). Under 02D .0530(h), the best available control technology (BACT) limit was determined to be 2.0 ppm of NOx for the first 500 hours of operation and 2.5 ppm thereafter on a 30-day rolling average, which is more stringent than the alternative.[7] In addition, the BACT limit included several specific provisions:

- Emission limit exemptions for periods of startup, shutdown, and malfunction,
- Limits on excess emissions due to startup and shutdown, and
- Specific definitions of startup and shutdown.

DAQ determined that 02D .0530(h) no longer applied to the turbines with the T26 permit revision. As part of that revision, DEC agreed to keep the former BACT limit when determining compliance with 02D .1418.[8] Limits formerly included in the permit under 02D .0530(h) were moved to the section for 02D .1418 instead. The specific provisions mentioned above were also included in the section for 02D .1418.

In order to comply with the NOx emission limit, DEC operates selective catalytic reduction (SCR) to reduce NOx emissions. In order to demonstrate compliance, DEC operates a NOx CEMS and monitors the ammonia injection rate for the SCR. DEC must keep records of NOx emissions and submit a report twice per year.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections.

12. 15A NCAC 02Q .0317 "Avoidance Conditions"

DEC has accepted enforceable emission limits in order to avoid additional requirements under 02D .0530, 02D .0531, and 02D .0501(c).

[6] See Appendix G of DEC's application submitted on April 24, 2017 (application 8000004.17B). In response to this application, DAQ issued the T35 permit revision (issued May 10, 2018).
[7] See pages 9, 10, and 21 of the application review for the T22 permit revision (issued October 15, 2008).
[8] See pages 2 and 3 of the application review for the T26 permit revision (issued February 4, 2011).

i. Avoidance of 02D .0530 "Prevention of Significant Deterioration" (PSD)

In order to avoid PSD applicability to the STAR® process and the two turbines, DEC has accepted the limits and requirements listed in Table 3:

Table 3: Summary of PSD Avoidance Requirements

Emission Source	Pollutant / Limit	Requirements	Notes
Turbines (ES-11 and ES-12)	• CO, 147 tpy[9] • NOx, 599.8 tpy[9] • PM, 198.9 tpy[9] • PM_{10}, 160.8 tpy[9] • sulfuric acid, 18.5 tpy[9]	• Operate control devices, • Operate NOx CEMS, • Calculate and report CO and PM_{10} emissions using previously established emission factors,[10] • Limit fuel sulfur content	• Initially included in the T22 revision. At that time, the permit also limited the operation of the duct burners associated with ES-11 and ES-12. • The T22 revision also included specific definitions of startup and shutdown, and exemptions for emissions resulting from startup, shutdown, and malfunction. • Updated in the T29 revision. This changed the duct burner limit from hours of operation to total heat input. • Updated again in the T31 revision. This removed the duct burner operating limit.
STAR® process (ES-73 through 85, ES-F1 through F6)	• PM, 108.2 tpy	• Limit hours of operation, heat input, and total flyash processing, • Limit ash basin size, total truck loads, and truck driving distance, • Periodic emission testing of ES-74, • Keep records of operations, • Calculate and report PM emissions.	• Initially included in the T35 revision. • Updated in the T36 revision to include emission sources added during that revision.

DAQ has determined that data substitution should be required where CEMS are being used to demonstrate compliance with a long-term emission limit. Because DEC is using a NOx CEMS to demonstrate compliance with an annual emission limit for the turbines, the existing permit will be updated to require data substitution (using the procedure in 40 CFR Part 75) for data gathered from the NOx CEMS.

[9] In the existing permit, this limit is incorrectly written in units of "tons per 12-month rolling average." This should have always been the 12-month rolling total, not average. The emission calculation method in the permit has always correctly produced results in units of 12-month rolling total, and DEC has been reporting results in units of 12-month rolling total. In the renewed Title V permit, this limit will be written in the correct unit. This change will not affect DEC's compliance requirements, given that DEC has already been demonstrating compliance with the limit as it was intended.
[10] These emission factors are based on a conservative review of similar units at the Duke – Dan River facility (facility ID 7900015). See page 7 of the application review for the T31 permit revision for details (issued February 23, 2015).

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

ii. Avoidance of 02D .0531 "Sources in Nonattainment Areas" (a.k.a. NSR)

In order to avoid applicability of NSR requirements for the two turbines, DEC accepted a limit on VOC emissions from the turbines.

Table 4: Summary of NSR Avoidance Requirements

Emission Source	Pollutant / Limit	Requirements	Notes
Turbines (ES-11 and ES-12)	• VOC, 44.7 tpy[11]	• Operate control devices, • Calculate and report VOC emissions using previously established emission factors.[12]	• Initially included in the T22 revision. This limit was added separately from the PSD avoidance limits above because this facility was located in an area of ozone nonattainment at that time. Rowan County has since been reclassified as not nonattainment. • The T22 revision also included the definitions and exemptions for startup, shutdown, and malfunction mentioned in Section 6.12.i, above.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

iii. Avoidance of 02D .0501(c) "Emission Control Standards"

During the T22 permit revision, it was determined that the auxiliary boiler would need an operational limit to ensure compliance with the National Ambient Air Quality Standards (NAAQS). This limit was added separately to the PSD and NSR limits above because the auxiliary boiler was already present at the facility was not being modified as part of the T22 revision.

In order to avoid potential NAAQS violations, DEC must limit the sulfur content of the gas burned in the boiler to less than 2.0 grains of sulfur per 100 standard cubic feet and limit the annual hours of operation of the boiler to less than 2,000 per year. DEC demonstrates compliance by recording gas sulfur content from the vendor and keeping records of operating hours of the boiler.

Based on the most recent inspection report, DEC appears to be in compliance with this rule. Continued compliance will be determined with subsequent inspections and reports.

13. 15A NCAC 02Q .0400 "Acid Rain Procedures"

This rule incorporates the acid rain program (40 CFR Part 72) into North Carolina's SIP.

The specific requirements for the acid rain program are included in the Phase II permit application submitted by DEC. The Phase II permit application and requirements are included in the Title V permit

[11] See note 9.
[12] See note 10.

as an attachment. As requested by application 8000004.20A, the Title IV permit will be renewed with the same expiration date as the Title V permit.

In general, compliance with the acid rain program is determined by USEPA, not DAQ. Continued compliance will be determined by US EPA.

14. 15A NCAC 02Q .0711 "Emission Rates Requiring a Permit"

This rule requires a facility that emits TAP at rates greater than the limits in 02Q .0711 to submit air dispersion modeling such that compliance with 02D .1100 and 02D .1104 is demonstrated.

DEC has previously submitted air dispersion modeling (discussed in Section 6.7). At that time, it was determined that DEC had no further requirements to demonstrate compliance with 02Q .0711. TAPs that were not included in the modeling demonstration are included in the permit for future reference.

15. Cross State Air Pollution Rule (CSAPR; 40 CFR Part 97, Subparts AAAAA and CCCCC)

This group of rules applies to fossil-fuel-fired combustion sources that 1) produce electricity for sale, and 2) have a generator capacity greater than 25 megawatts. Each combustion turbine at this facility is subject to CSAPR because it serves a generator with capacity greater than the threshold.

CSAPR limits NOx and SO_2 emissions. In general, CSAPR requires tracking and trading emission credits across multiple facilities, including facilities not within the state of North Carolina. Therefore, compliance with CSAPR is generally determined by US EPA.

The existing permit includes a reference to 40 CFR Part 97, Subpart BBBBB "CSAPR NOX Ozone Season Group 1 Trading Program." This rule applies to areas that are part of the summer ozone season trading program. As of 2017, North Carolina is not such an area. Because Subpart BBBBB does not apply to this facility, all references to this rule have been removed from the permit. For further discussion of the nonapplicability of Subpart BBBBB, see 40 CFR 52.1784(b) and 81 FR 74504.

Note that the CSAPR rules are not currently included in North Carolina's SIP. The Title V permit contains a reference to CSAPR and the relevant portions of 40 CFR Part 97, but no specific compliance requirements.

16. Nonapplicable Rules:

There are several SIP and Federal rules that could potentially apply at this renewal, but ultimately do not. The following discussion addresses the applicability of these rules.

i. 15A NCAC 02D .0530 "Prevention of Significant Deterioration" (PSD) and
15A NCAC 02D .0531 "Sources in Nonattainment Areas" (a.k.a. New Source Review, NSR)

This facility is a major source for PSD because of coal-fired boilers previously operated at this facility. Although those sources have been removed as of the T31 permit revision (issued February 23, 2015), this facility is still considered a major source with regards to PSD.

Regardless of the classification, this facility has no requirements under PSD because all sources that were previously subject to specific requirements under PSD have been removed from the facility. DEC is avoiding triggering new requirements under PSD and NSR by complying with enforceable emission limits (discussed in Section 6.12).

ii. <u>15A NCAC 02D .0530(u) "Use of Projected Actual Emissions"</u>

The existing permit includes a requirement to report actual emissions resulting from the T30 permit modification through CY2020. DEC has no further requirements after the reporting period ends.

Now that the reporting period for this modification has ended, DEC has no further requirements under this rule, and all references to this rule will be removed from the permit. See Section 5.4 for a discussion of DEC's previous requirements under this rule.

iii. <u>15A NCAC 02D .0614 "Compliance Assurance Monitoring" (CAM; 40 CFR Part 64)</u>

The compliance assurance monitoring (CAM) rule requires owners and operators to conduct monitoring to provide a reasonable assurance of compliance with applicable requirements under the act. Monitoring focuses on emissions units that rely on pollution control device equipment to achieve compliance with applicable standards. An emission unit is subject to CAM, under 40 CFR Part 64, if all of the following three conditions are met:

I. The unit is subject to any (non-exempt, e.g., pre-November 15, 1990, Section 111 or 112 standard) emission limitation or standard for the applicable regulated pollutant.
II. The unit uses any control device to achieve compliance with any such emission limitation or standard.
III. The unit's pre-control potential emission rate exceeds 100 percent of the amount required for a source to be classified as a major source; i.e., either 100 tpy (for criteria pollutants) or 10 tpy of any individual/25 tpy of any combination of HAP.

Table 5 compares each control device at this facility to the above criteria:

Table 5: CAM Applicability Analysis

Control Device	Associated Emission Sources	Emission Limit / Rule	Triggers CAM?	Notes
Selective catalytic reduction, controlling NOx	Turbines (ES-11 and ES-12)	02D .0524 (NSPS Subpart KKKK)	No	1
		02D .1418 (RACT)	No	
		02Q .0317 (PSD Avoidance)	No	2
		02Q .0400 (Acid Rain Permit)	No	3
		40 CFR Part 97 (CSAPR)	No	4
Oxidation catalyst, controlling CO and VOC	Turbines (ES-11 and ES-12)	02Q .0317 (PSD Avoidance)	No	2
Fabric filter, controlling PM	STAR® (ES-74)	02D .0515	No	5
		02Q .0317 (PSD Avoidance)	No	2

Control Device	Associated Emission Sources	Emission Limit / Rule	Triggers CAM?	Notes
Flue-gas desulfurization, controlling SO_2	STAR® (ES-74)	02D .0516	No	6
Air staging and water injection, controlling NOx	STAR® (ES-74)	02D .1413	No	7
Fabric filters, controlling PM	STAR® associated sources (ES-73, ES-75 through ES-82, ES-84, and ES-85)	02D .0515	No	8
		02Q .0317 (PSD Avoidance)	No	

Notes:

1. The use of a NOx CEMS constitutes a continuous compliance determination method (CCDM). Limits that are associated with a CCDM are exempt from CAM per 02D .0614(b)(1)(F). The use of NOx CEMS is required for these sources to demonstrate compliance with NSKS Subpart KKKK and RACT. NOx CEMS requirements are discussed in Sections 6.5.iii and 6.11 above. Therefore, CAM is not required per item I above.
2. This is an emissions cap under Subchapter 02Q, which is exempt from CAM per 02D .0614(b)(1)(E). Therefore, CAM is not required per item I above.
3. Acid Rain Program requirements are exempt from CAM per 02D .0614(b)(1)(C). Therefore, CAM is not required per item I above.
4. CSAPR is an emissions trading program, which is exempt from CAM per 02D .0614(b)(1)(D). Therefore, CAM is not required per item I above.
5. This source does not potential emissions of PM greater than the major source threshold. Therefore, CAM is not required per item III above.[13]
6. The use of a SO_2 CEMS constitutes a CCDM. Limits that are associated with a CCDM are exempt from CAM per 02D .0614(b)(1)(F). The use of SO_2 CEMS is required for this source to demonstrate compliance with 02D .0516. SO_2 CEMS are discussed in Section 6.3 above. Therefore, CAM is not required per item I above.
7. Although air staging and water injection are considered the control technology for RACT, these are not control devices for CAM purposes. Air staging and water injection are inherent to the STAR® process.[14] In 40 CFR 64.1, the CAM rule states that "inherent process equipment is not considered a control device."
8. These control devices are not control devices for CAM purposes. As noted in Section 1 of the existing permit, these sources are "Non-optional air pollution control equipment that constitutes an integral part of the process equipment as originally designed and manufactured by the equipment supplier." In 40 CFR 64.1, the CAM rule states that "inherent process equipment is not considered a control device."

Based on the above analysis, CAM does not apply to any control device at this facility.

[13] See page 9 of the application review for the T36 permit revision (issued April 3, 2020). Note that the major source threshold for PM is 100 tons per year, which corresponds to an hourly emission rate of approximately 22.83 pounds per hour.
[14] See note 6. Also, see page 13 of the application review for the T35 permit revision (issued May 10, 2018).

iv. 15A NCAC 02D .1408 "Stationary Combustion Turbines"

Per 02D .1408(b), this rule applies to turbines with a heat input between 100 and 250 million Btu per hour and located in an area listed in 02D .1402. Each turbine at this facility has a heat input greater than 250 million Btu per hour, so this rule does not apply.

v. 15A NCAC 02D .1409 "Stationary Internal Combustion Engines"

This rule applies to engines with a capacity greater than or equal to 650 horsepower, not covered by 02D .1418, and are located in an area listed in 02D .1402. The rule includes NOx limits for rich-burn, lean-burn, and compression ignition engines. Note that, per the definitions in 02D .1401, rich- and lean-burn engines only include spark ignition engines (i.e., turbines are not considered for this rule).

Table 6 summarizes the stationary internal combustion engines at this facility:

Table 6: Engine Applicability for 15A NCAC 02D .1409

Source	Description	Subject?	Notes
I-4	11 kW propane-fired emergency generator	No	1
ES-15	1,490 horsepower No. 2 oil-fired emergency generator	No	2
ES-16	237 horsepower No. 2 oil-fired firewater pump	No	1
ES-17EmGen	762 horsepower No. 2 oil-fired emergency generator	No	2
ES-82B1 and ES-82B2	225 horsepower diesel-fired engine for a vibrating screener (each)	No	1
ES-82D1 through ES-82D6	74 horsepower diesel-fired engine for a tele-stacker (each)	No	1
ES-86	74 horsepower diesel-fired engine for a basin dewatering pump	No	1

Notes:
1. Capacity less than 650 horsepower.
2. 02D .1402(h)(3) specifically states that rules under chapter 02D .1400 do not apply to emergency generators.

Based on the above analysis, 02D .1409 does not apply to this facility.

vi. 15A NCAC 02D .1423 "Large Internal Combustion Engines"

This rule applies to large internal combustion engines that are subject to 15A NCAC 02D .1418 but are also not subject to 15A NCAC 02D .0530.

This rule only applies to reciprocating internal combustion engines with a capacity greater than 2,400 horsepower based on 02D .1423(a)(1)-(4) and the definitions in 02D .1401.

Turbines are not reciprocating engines, so they are not subject to this rule. Each reciprocating engine at this facility has capacity less than 2,400 horsepower, so they are not subject to this rule.

vii. 15A NCAC 02D .2100 "Risk Management Program" (a.k.a. §112(r), Section 112(r) of the Clean Air Act)

In the application for the .21A, DEC indicated on form A3 that no Risk Management Plan (RMP) is required for this facility. The application states "Although the facility uses liquid ammonia in the SCR units, the ammonia concentration does not exceed the 20% threshold for RMP applicability."

This facility does not appear to store any materials above their respective thresholds in 40 CFR 68.130. Therefore, this facility is not required to submit a Risk Management Plan and has no specific requirements under 02D .2100. Note that other requirements under §112(r) (such as the General Duty Clause) may apply to this facility.

viii. 15A NCAC 02Q .0504 "Option for Obtaining Construction and Operation Permit"

The existing permit includes a requirement to submit a "second step" application. With the submittal of application .21A, DEC has satisfied the requirement to submit such an application. DEC has no further requirements under this rule, and all references to this rule will be removed from the permit. See Section 5.1 for a discussion of DEC's previous requirements under this rule.

ix. 40 CFR Part 60, Subpart CCCC "Standards of Performance for Commercial and Industrial Solid Waste Incineration Units" (CISWI)

This rule applies to units that meet the definition of a new commercial and industrial solid waste incineration unit. The STAR® reactor could potentially be subject to this rule because it will burn flyash. However, DAQ has previously determined that the STAR® reactor will not be subject to this rule:

> "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."[15]

As discussed in Section 5.5, DEC plans to include fire retardant additives in the flyash. The use of these additives will not affect the NHSM determination. See Attachment 3 for details.

x. 40 CFR Part 60, Subpart TTTT "Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units"

Per §60.5509(a), this rule applies to electric generating units (such as combustion turbines powering generators) that were constructed or reconstructed after June 18, 2014. Each turbine at this facility was constructed before this date, and have not been reconstructed after this date. Therefore, this rule does not apply to this facility.

[15] See page 14 of the application review for the T35 permit revision (issued May 10, 2018).

xi. 40 CFR Part 63, Subpart EEE "National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors"

This rule applies to all hazardous waste combustors. The STAR® reactor could potentially be subject to this rule because it will burn flyash. However, as discussed in Section 6.16.ix, DAQ has determined that flyash is specifically a non-hazardous secondary material. Therefore, the STAR® reactor does not burn hazardous waste, and this rule does not apply.

7. Compliance Status and Other Regulatory Concerns:

- *Compliance status*: This facility was most recently inspected on November 20, 2020 by Jim Vanwormer. DEC appeared to be in compliance with the Title V permit during that inspection.

- *Compliance history*: There have been no Notices of Violation issued to this facility since the previous Title V permit renewal.

- *Application fee*: Applications for significant modification require an application fee. DEC paid the required fee for application .21A. Applications for renewal of a Title V and/or Title IV permit do not require an application fee.

- *PE Seal*: Pursuant to 15A NCAC 02Q .0112 "Application requiring a Professional Engineering Seal," a professional engineer's seal (PE seal) is required to seal technical portions of air permit applications for new sources and modifications of existing sources as defined in Rule .0103 of this Section that involve:

  (1) design;
  (2) determination of applicability and appropriateness; or
  (3) determination and interpretation of performance; of air pollution capture and control systems.

  A PE Seal was **NOT** required for the .21A application because the need for a PE seal was addressed in the Part 1 application (applications .17B and .19A). Title V and Title IV permit renewals do not require a PE seal.

- *Zoning*: A Zoning Consistency Determination per 02Q .0304(b) was **NOT** required for the .21A application because this was addressed in the Part 1 application (applications .17B and .19A). A zoning consistency determination is not required for Title V and Title IV permit renewals.

8. Facility Emissions Review

The table on the first page of this permit review presents the criteria pollutant (plus total HAP) from the latest available approved facility emissions inventory (2019). The HAP emitted in the largest quantity from the facility is n-hexane. The changes to the permit discussed in Section 5 above are not expected to change the potential to emit any emissions from this facility.

9. Draft Permit Review Summary

Initial draft: A draft of the permit and this application review were sent to RCO and SSCB staff on March 8, 2021. Below is a summary of comments received from RCO and SSCB.

RCO Comment 1: Various typos in draft permit and review.

RCO Comment 2: The application review should address the potential applicability 02D .1409 and re-examine the potential applicability of 02D .1413.

RCO Comment 3: The application review should be clearer as to why an RMP is not required.

RCO Comment 4: The permit should include the phrase "All instances of deviations from the requirements of this permit must be clearly identified" for all reporting requirements.

SSCB Comment 1: When reporting CEMS monitor performance, CEMS downtime should be calculated on a quarterly basis.

All of the above comments were addressed, and a new draft of the permit and application review were prepared.

Second draft: A draft of the permit and this application review were sent to MRO and DEC staff on April 7, 2021. No comments were received from MRO. DEC responded on May 18, 2021 that there were no comments on this draft.

Subsequent draft: Based on the amended application received May 18, 2021 and responses from DEC received June 8, July 27, and October 7, 2021, and February 16, 2022, a new draft of the Title V permit and application review were prepared and sent to DEC staff on March 3, 2022. No comments were received on this draft.

10. Public Notice, EPA Review, and Affected State(s) Review

A notice of the DRAFT Title V Permit shall be made pursuant to 15A NCAC 02Q .0521. The notice will provide for a 30-day comment period, with an opportunity for a public hearing. Consistent with 15A NCAC 02Q .0525, the EPA will have a concurrent 45-day review period. Copies of the public notice shall be sent to persons on the Title V mailing list and EPA. Pursuant to 15A NCAC 02Q .0522, a copy of each permit application, each proposed permit and each final permit shall be provided to EPA. Also, pursuant to 02Q .0522, a notice of the DRAFT Title V Permit shall be provided to each affected State at or before the time notice is provided to the public under 02Q .0521 above. South Carolina is an affected state.

- The Public Notice and EPA Review periods began on XXXX.
- The Public Notice period ended on XXXX.
- The EPA Review period ended on XXXX.

11. Recommendations

This permit application has been reviewed by NC DAQ to determine compliance with all procedures and requirements. NC DAQ has determined that this facility appears to be complying with all applicable requirements.

Recommend issuance of Permit No. 03786T37. MRO has received a copy of this permit and no comments were received, as described in Section 9.

Attachment 1 to Review of Applications 8000004.20A, .20B, & .21A
Duke Energy Carolinas, LLC - Buck Combined Cycle Facility:
Review of Application 8000004.17B

In response to this application, DAQ issued permit 03786T35 on May 10, 2018.
(page numbers in this attachment may differ from the original document due to formatting differences)

Review Engineer: Kevin Godwin **Review Engineer's Signature:** **Date:** [signed by Kevin Godwin on Permit Issue Date]	**Comments / Recommendations:** **Issue** 03786/T35 **Permit Issue Date:** 05/10/2018 **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]

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[1] Maryland Department of Natural of Natural Resources (DNR) Publication No. 12-382012-556Morgantown STAR ERD - Case No. 9229, March 2012.

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 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,

[2] U.S. EPA, Coal Ash Reuse, https://www.epa.gov/coalash/coal-ash-reuse; Accessed May 10, 2017

	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.
April 10, 2018	A Public Hearing was held at North Rowan High School, Spencer, North Carolina.
May 10, 2018	A Final Permit was issued.

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

<u>Facility Expansion</u>

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

<u>Fly Ash Truck Unloading Options</u>

- 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.

<u>Other Fugitive Fly Ash Sources</u>

- 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 5.2, 04/03/2018).

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
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

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?
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
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

[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)

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 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

<u>15A NCAC 02D .0524, New Source Performance Standards</u>
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.

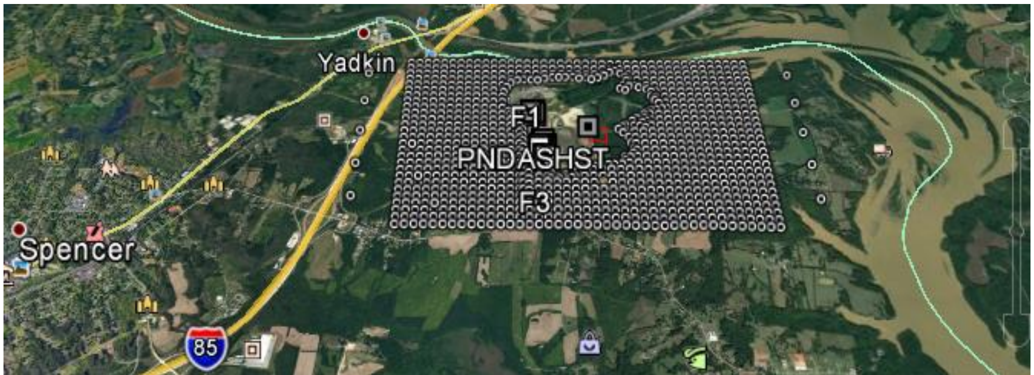
The minimum lime to sulfur ratio will apply when the STAR® system is operating except during periods of startup, shutdown or malfunction. During normal operations, any three-hour rolling period that the lime to sulfur ratio falls below the minimum established value will be considered an excursion. Each 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

Emission Source	Toxic Air Pollutant	Emission Limit(s)
	Mercury	3.13E-05 lb/day
	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	Arsenic	4.62E-03 lb/yr
	Beryllium	9.56E-04 lb/yr

Emission Source	Toxic Air Pollutant	Emission Limit(s)
(ID No. ES-80A/B) (Total)	Cadmium	8.24E-04 lb/yr
	Chromium VI (Soluble Chromate)	6.48E-06 lb/day
	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

Emission Source	Toxic Air Pollutant	Emission Limit(s)
	Mercury	8.95E-08 lb/day
	Nickel Metal	1.69E-05 lb/day
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 was published in the *Salisbury Post* and posted to the DAQ website on March 9, 2018.

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. A summary of the public hearing is provided in Attachment I. The Division recommends permit issuance.

Attachment I [to Review of Application 8000004.17B]: Public Hearing Summary

Time: 7:00 P.M.
Date: April 10, 2018 (comment period expired April 15, 2018)
Location: North Rowan High School, 300 N. Whitehead Avenue, Spencer, NC 28159

Comments: See Hearing Officers Report

Attachment 2 to Review of Applications 8000004.20A, .20B, & .21A
Duke Energy Carolinas, LLC - Buck Combined Cycle Facility: Review of Application 8000004.19A

In response to this application, DAQ issued permit 03786T36 on April 3, 2020.
(page numbers in this attachment may differ from the original document due to formatting differences)

Review Engineer: Rahul Thaker Review Engineer's Signature: Date: April 3, 2020 [Signed by Rahul Thaker on Permit Issue Date]	Comments / Recommendations: Issue 03786/T36 Permit Issue Date: 04/03/2020 Permit Expiration Date: 07/31/2021

1. Purpose of Application

Duke Energy Carolinas LLC, Buck Combined Cycle Facility, Salisbury, Rowan County, NC (hereinafter DEC or Buck), submitted an application to obtain an air permit for the design changes, associated with the previously approved coal ash beneficiation project (Air Quality Permit 03786T35, May 10, 2018). The requested changes are as follows:

- Add Ball Mill Classifier and Ball Mill Feed Silo
- Update of annual emissions for criteria pollutants (except lead) to account for 10 days of down time for routine maintenance for the STAR® (Staged Turbulent Air Reactor), External Heat Exchangers (EHEs), and Ball Mill Classifier, while keeping annual emissions for lead and other pollutants based on 8,760 hours of operation
- Update $PM_{2.5}$ speciation for the STAR®, EHEs, and Pollution Control Silos, based on vendor data
- Remove Compliance Assurance Monitoring (CAM) requirement for SO_2 for STAR® due to the proposed use of continuous emissions monitoring system (CEMS)
- Revise sulfur concentration (percent sulfur by weight) in feed ash
- Remove permitted crusher and crusher engine
- Revise permitted screening operation to include two vibrating screeners with dedicated engines, and six tele-stackers with dedicated engines
- Increase ash basin working area from 10 acres to 25 acres
- Correct chromium (VI) emissions
- Revise stack parameters
- Update air toxic emissions for sources downstream of STAR® to include the metals emissions due to recycled water injection
- Optimize air toxics emissions to 98 percent of Acceptable Ambient Levels (AALs)

As requested, the DAQ will process this application pursuant to the 2-step procedure in 15A NCAC 02Q .0501(b)(2), essentially, using the 02Q .0300 program for the application processing. The applicant will be required to submit another application, pursuant to the Title V program in 02Q .0500, within 12-months of beginning of operation of the coal ash beneficiation project emission sources.

2. Application Chronology

July 2, 2019	Received the application. DAQ classified it as a 1-step significant modification.
January 24, 2020	DEC requested DAQ to prioritize this application for the coal ash beneficiation project redesign. Until this date, DAQ was processing a separate application (PSD) for the "solar influx" project for the same facility. The DAQ did not initiate the processing of the coal ash redesign application until after this request from the DEC.
February 18, 2020	DAQ reclassified the application as a 2-step significant modification under 02Q .0501(b)(2), because, the modification does not conflict or contravene any of the conditions in the existing permit.

3. Facility Information

DEC owns and operates the Buck Combined Cycle Facility. It is a 620-megawatt nominal capacity electric power generating facility located on the Yadkin River in Salisbury, Rowan County, NC. It includes two fuel-efficient and clean burning combined cycle combustion turbine generators that burn a mixture of natural gas and compressed air – which turns a combustion turbine to generate electricity. These units recover heat from the exhaust gases to produce steam – which turns a separate steam turbine to produce additional electric power. This natural gas plant was placed into service in 2011 and is equipped with advanced emissions controls. A selective catalytic reduction (SCR) unit reduces nitrogen oxide emissions and an oxidation catalyst minimizes carbon monoxide (CO) and Volatile Organic Compounds (VOC) emissions.

The site originally began producing electricity in 1926 as a coal-fired steam station. However, all coal-fired units were retired on March 31, 2013[1]. 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.

4. Statement of Compliance

Based upon the most recent compliance inspection, conducted by the MRO (Jim Van Wormer) on November 20, 2019, “this facility appeared to be in compliance with the applicable air quality regulations.”

5. Permit Modifications

As stated in Section 1 above, the DAQ had earlier approved a coal beneficiation project for DEC’s Buck Combined Cycle Facility, consisting of a STAR® and several ancillary sources (described below).

This permitted project is designed to process annually a maximum 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, screeners and tele-stackers 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 per hour. Fuel and fly ash are then co-fired until the fly ash auto-ignition temperature (approximately 1,400 degrees ^{o}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 maximum 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

[1] As per US EPA’s Clean Air Markets Division’s Database.

gases from the product baghouse are directed to a dry FGD scrubber and bagfilter for emissions control before exiting through a stack (140 feet in height) into the atmosphere.

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]

It should be noted that the DAQ provides below, the inventory of all emissions sources of the redesigned STAR® project for ease of understanding. Most of these sources have already been permitted as stated earlier, except the new equipment and changes to the existing equipment described in Section 1 above. The emissions and regulatory applicability of the redesigned project equipment have been discussed in detail in the subsequent Sections 6 through 9 below.

Fugitive Emission Sources

Fly Ash Truck Unloading Options

- Wet Ash Receiving - Transfer of fly ash to storage shed (ID No. ES-F1) and then transfer to the feed hopper (ID No. F-2) at a rate up to 70 short tons per hour (tph) by a front-end loader. Both F-1 and F-2 sources are insignificant activities.

- Wet Ash Receiving - Transfer of fly ash to the feed hopper (ID No. ES-F2) at a rate up to 70 tph. As stated above, source F-2 is an insignificant activity.

- Wet Ash Receiving - Transfer to a 0.33-acre unloading storage pile (ID No. ES-F3) and then transfer to the storage shed (ID No. F-1) by a front-end loader. Source F-3 is an insignificant activity.

Other Fugitive Fly Ash Sources

- 67-Acre Ash Basin (ID No. ES-F4), which is an insignificant activity.
- Ash Handling up to 49.1 tph (ID No. ES-F5), which is an insignificant activity.
- Haul Roads (ID No. ES-F6), which is an insignificant activity.

Point Source Emission Units

- Screening operation consisting of two vibrating screeners (3/8") (ID Nos. ES-82A1 and ES-82A2) with dedicated engines (ID Nos. ES-82B1 and ES-82B2, each 225 HP output capacity) and six tele-stackers (ID Nos. ES-82C1 through ES-C6) with dedicated engines (ID Nos. ES-82D1 through ES-82D6, each 74 HP output capacity), with a capacity to produce 200 tph fine free flowing feedstock suitable for the STAR® reactor. These sources are insignificant activities.

- Two external heat exchangers (ID Nos. ES-77 and ES-78) with a combined total annual operation not to exceed 8,520 hours (excluding 10 days of down time for routine maintenance), drying a maximum of 70 tons per hour of fly ash suspended in transport air. Each exchanger will be controlled by a dedicated felted filter baghouse (ID Nos. CD-77 and CD-78).

- Ash feed silo (ID No. ES-73) with a storage capacity of 76,000 ft^3 for fly ash. Filled pneumatically at a rate of 125 tph and unloaded at the rate of 75 tph. An induced/negative draft bin vent (ID No. CD-73) will control particulate emissions. This is an insignificant activity.

- STAR® system (ID No. ES-74) with a 140 million Btu/hour maximum firing rate, processing feedstock (fly ash and other ingredient materials) into a variety of commercial products and equipped with natural gas/propane-fired low-NOx 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 (ID

[2] U.S. EPA, Coal Ash Reuse, available at https://www.epa.gov/coalash/coal-ash-reuse.

No. CD-74A) and bagfilter (ID No. CD-74B) for emissions control. The STAR® will be operating for not more than 8,520 hours (excluding 10 days of down time for routine maintenance) per year and it will be processing not to exceed 400,000 tons of coal ash per consecutive 12-months period.

- FGD byproduct silo (ID No. ES-75) 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 filter (ID No. CD-75) will control particulate emissions. This is an insignificant activity.

- FGD absorbent silo (ID No. ES-76) storing absorbent (hydrated lime) used in the dry FGD system and equipped with an induced/negative draft bin vent filter (ID No. CD-76) for particulate control. Silo specifications are TBD. This is an insignificant activity.

- Transfer silo (ID No. ES-79) with a capacity of 300 tons to store fly ash, filled pneumatically at a rate of 125 tph and unloaded at the rate of 75 tph. An induced/negative draft bin vent filter (ID No. CD-79) will control particulate emissions. This is an insignificant activity.

- Storage dome silo (ID No. ES-80) with a capacity of 30,000 tons to store fly ash, filled pneumatically at a rate of 75 tph and unloaded at the rate of 275 tph. An induced/negative draft bin vent filter (ID No. CD-80) will control particulate emissions. This is an insignificant activity.

- Loadout silo (ID No. ES-81) with an annual product throughput capacity of 400,000 tons, unloaded at a rate of 300 tph. An induced/negative draft bin vent filter (ID No. CD-81) will control particulate emissions. This is an insignificant activity.

- Two loadout silo chutes (ID Nos. ES-81A and ES-81B) with annual product throughput capacity of 200,000 tons each, each equipped with a bin vent capture device (ID Nos. CD-81A and CD-81B) and unloaded at a rate of 100 tph. These are insignificant activities.

- Ball mill storage silo (ID No. ES-85), filled pneumatically at a rate of 15 tph and unloaded at a rate of 15 tph. An induced/negative draft bin vent filter (ID No. CD-85) will control particulate emissions. This is an insignificant activity.

- Ball mill classifier (ID No. ES-84) with a capacity of 11,081 acfm. An induced/negative draft bin vent filter (ID No. CD-84) will control particulate emissions. This source will be operating for not more than 8,520 hours (excluding 10 days of down time for routine maintenance) per year. This is an insignificant activity.

It needs to be clarified that bagfilters/filters associated with various STAR® facility sources are integral to the process as material is being pneumatically conveyed. As per the DEC, without the baghouse/filter to separate the transfer air from the solid material, the system would not operate. In brief, the bagfilters/filters on various STAR® facility sources are not air pollution control devices and are product recovery devices. Thus, the pre- and post-control emissions for the associated emission sources are the same. Except the STAR® and two EHEs, all other sources can be classified as insignificant sources. However, for clarity and streamlining purposes, with regard to applicable requirements, all STAR® facility sources (regardless of their status as significant or insignificant) will be included in the body of the permit with the detailed requirements.

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 pollutants 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. Finally, products of combustion and toxic/hazardous air pollutant emissions are also expected from stationary engines, namely, two vibrating screener engines and six tele-stacker engines.

CO and 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. Additionally, two screener engines and six tele-stacker engines will also emit CO and VOCs, because of the incomplete combustion.

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. 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 million Btu. 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 million Btu. Duke Energy expects to emit from the STAR® system no more than 0.12 pounds of NO_x per million Btu, which the DAQ has earlier established as the RACT (Reasonably Available Control Technology) for the STAR®. Additionally, NO_x will be emitted from the two screener engines and six tele-stacker engines will also emit CO and VOCs because of the incomplete combustion.

PM, PM10, PM2.5 - Particulate emissions from STAR® 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 0.025 grain per actual cubic foot (acf). The induced draft fan moving the product transfer is rated at 77,500 acf per minute. Additionally, two screener engines and six tele-stacker engines will also emit PM because of the incomplete combustion.

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 the STAR® system will be controlled by a dry scrubber that is designed to reduce SO_2 emissions by 95 percent. Two screener engines and six tele-stacker engines will also emit SO_2 due to conversion (oxidation) of sulfur in diesel fuel.

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.

TAPs/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. For the entire redesigned project, approximately 0.464 tons of formaldehyde (single largest HAP) are expected to be emitted each year. Total HAPs are estimated to be only 0.61 tons/yr.

Emission Factors - Duke Energy has relied on both its fly ash and recycled water analysis, and the information provided by the SEFA Group Inc., to estimate emissions from the STAR® system. DEC also used the applicable EPA AP-42 "Compilation of Air Emission Factors" and NSPS (mainly for engines) to estimate emissions as detailed in the following Table 6-1.

As stated previously, for STAR®, two EHEs, two pollution control silos, and ball mill classifier, the particulate emissions are to be controlled by the dedicated filters (bin vent, fabric filter). The applicant has based the PM10 emissions for these sources at a rate of 92 percent (by weight) of PM[3]. For PM2.5 emissions, the applicant has estimated that 23 percent of mass leaving the filter (bagfilter, vent filter) will be PM2.5[4].

Finally, GHG emissions (for STAR® and engines) are based on loss of ignition and emission factors from Table C-1 of 40 CFR Part 98, as applicable.

Table 6-1 Source of Emission Factor

Source of Emission Factor AP-42 Chapter/NSPS	**Emission Source(s)**
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 and NSPS Subpart IIII	Vibrating Screener Engines (ES-82B1 and ES-82B2) Tele-Stacker Engines (ES-82D1 through ES-82D6)
11.19 Construction Aggregate Processing	Vibrating Screeners (ES-82A1 and ES-82A2) Tele-Stackers (ES-82C1 through ES-82C6)
13.2-2 Unpaved Roads	Haul Roads (F-6)
13.2-4 Aggregate Handling and Storage Piles	Feed Silo (ES-73) Transfer Silo (ES-79) Ball Mill Feed Silo (ES-85) Loadout Silo (ES-81) Loadout Chutes (ES-81A and ES-81B) Storage Dome Silo (ES-80) Wet Ash Receiving – Both Transfer to Shed and Transfer to Hopper (F-1 and F-2) Wet Ash Receiving – Transfer to Hopper (F-2) Ash Handing (F-5)
13.2-5 Industrial Wind Erosion	Wet Ash Receiving – Unloading Pile (F-3) Ash Basin (F-4)

Potential Emissions - The applicant has estimated the maximum short-term emissions (e.g., lb/hr) of STAR® system, operating continuously at a design rate of 140 million Btu per hour and the auxiliary burners operating continuously at the design rate of 60 million Btu per hour.

Emissions of PM, PM10, PM2.5, SO_2, NOx, CO, and VOC, due to fly ash processing, are based on annual operation of 8,520 hours (considering 10 days of down time for routine maintenance). For all other pollutants including HAPs and TAPs, emissions due to fly ash processing are based on 8,760 hours. For natural gas or propane firing, the emissions of all pollutants are based on 8,760 hours of operation.

In addition, except for NOx, CO, VOCs, PM, PM10, and PM2.5, and SO2 (i.e., for all other pollutants including HAPs and TAPs), the higher of the two maximum emission rates from natural gas and propane firing is added to the emissions due to fly ash processing.

For NOx, CO, and VOCs, the potential emissions are based on higher of fuel combustion (natural gas or propane) at a rate of 60 million Btu/hr and the remainder heat input rate (i.e., 70 million Btu/hr) for fly ash processing at an annual average rate of 130 million Btu/hr (i.e., 130-60 = 70).

For PM, PM10, and PM2.5, emissions are based on flue gas flow rate and bagfilter control efficiency (0.02 grain/scf).

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[3] Table 1.1-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS AND SUBBITUMINOUS COAL, AP-42, 9/98.
[4] Per MEGTEC LLC.

For SO_2, emissions are based upon both fuel sulfur and sulfur content of fly ash, LOI, dry scrubber control efficiency (95% by weight).

The following Table 6-2 includes the potential emissions for the STAR® system only.

Table 6-2 Potential Emissions for STAR® System Only

Pollutant	Potential to Emit (Controlled) Ton/Yr Fly Ash Processing + Worst Case Fuel
CO	88.61
NOx	73.53
PM	70.75
PM10	65.09
PM2.5	16.27
SO_2	95.49
VOC	8.86
Lead	0.0094
Sulfuric Acid Mist	0.44
GHGs as CO2e	116,406

Potential emissions for the entire (redesigned) project are included below in Table 6-3:

Table 6-3 Potential Emissions for Entire STAR® Facility

Pollutant	STAR® System Ton/Yr	Diesel Engines Ton/Yr	Ash/Product Handling and Fugitives Ton/Yr	Total Ton/Yr
CO	88.61	7.80	0.00	96.41
NOx	73.53	5.64	0.00	79.17
PM	70.75	0.544	36.92	108.21
PM10	65.09	0.544	31.91	97.54
PM2.5	16.27	0.544	7.83	24.64
SO_2	95.49	2.32	0.00	97.81
VOC	8.86	2.42	0.00	11.28
Lead	0.0094	0.0000714	0.00463	0.0141
Sulfuric acid Mist	0.44	0.00	0.00	0.44
GHGs as CO_2e	116,406	1298.1	0.00	117,699

7. Applicable Regulations

The project sources are subject to the following regulations:

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, Subpart 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, Subpart ZZZZ)
15A NCAC 02D .1413	[Nitrogen Oxide] Sources Not Otherwise Listed in This Section [02D .1400]
15A NCAC 02Q .0317	Avoidance of Prevention of Significant Deterioration
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) is addressed in Section 8 below. Air Toxics (02D .1100 and 02Q .0711) compliance is discussed in Section 9 below.

15A NCAC 02D .0515 Particulates from Miscellaneous Industrial Processes

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 equations.

For process rates of no more than 30 tons per hour: $E = 4.10 \times P^{0.67}$
For process rates of more than 30 tons per hour: $E = 55.0 \times P^{0.11} - 40$

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

The Table 7-1 below shows the process rate, allowable PM emission rate, and potential pre-control and post-control filterable PM emissions rate for each emission source, subject to this rule.

Table 7-1 Summary of Allowable Particulate Emissions

Emission Source	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	0.0061	0.0061	Yes
Feed silo unloading	73B	75	48.4	0.00366	0.00366	Yes
STAR® reactor	74	75	48.4	16.61	16.61	Yes
FGD byproduct silo	75	TBD	TBD	0.06	0.06	Yes
FGD absorbent silo	76	TBD	TBD	0.06	0.06	Yes
EHE (Units 1/2)	77/78	70	47.8	6.86	6.86	Yes
Storage dome silo filling	80A	75	48.4	0.0037	0.0037	Yes
Storage dome silo unloading	80B	275	62.0	0.0134	0.0134	Yes
Transfer silo filling	79A	125	53.5	0.0061	0.0061	Yes
Transfer silo unloading	79B	75	48.4	0.0037	0.0037	Yes
Loadout silo	81	300	63.0	0.0146	0.0146	Yes
Loadout chute (1A/1B)	81A/81B	100	51.3	0.005	0.005	Yes
Vibrating screeners Tele-stackers	82A1/82A2 82C1 through 82C6	200 200	58.5 58.5	0.44 0.028	0.44 0.028	Yes Yes
Ball mill classifier	84	15	25.16	0.78	0.78	Yes
Ball mill feed silo	85	15	25.16	0.0015	0.0015	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 vibrating screeners and tele-stackers are subject to SO_2 standard (as fuel sulfur) in 02D .0524; thus, they are not subject to this rule. Thus, 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 33 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, as shown in Table 7-2 below, compliance with this rule is expected with emissions control.

Table 7-2 Allowable SO_2 Emissions

STAR® System Fuel	Maximum Sulfur Content	Heat Input Rate Million Btu/hr	Potential SO2 before control lb/million Btu	Potential SO2 after control lb/million Btu	Compliance?
Fly ash	0.15 % by weight	140	3.45	0.17	Yes
Natural gas/propane low-NOx burners	0.6 lbs/million cubic feet[5]	60	<0.001	<0.001	Yes

It should be noted that the 02D .0516 permit condition currently includes a streamlined monitoring approach. That is, the DAQ had previously concluded that the compliance with the monitoring/recordkeeping and reporting requirements under the permit condition under the CAM (Compliance Assurance Monitoring) will be adequate to comply with the 02D .0516.

However, as discussed above in Section 1, the Permittee has requested to remove the CAM requirement from the permit as it has proposed in this application the use of CEMS to monitor SO_2 emissions. In summary, the DAQ will remove the existing CAM requirement under 02D .0614 and include all appropriate requirements for monitoring SO_2 emissions using the CEMS to comply with 02D .0516, as follows.

To ensure compliance, the Permittee shall install a sulfur dioxide continuous emissions monitoring (CEMS) system including any required diluent monitor system with the following requirements:

i. The CEM system shall be installed, calibrated, maintained, tested, and operated in accordance with 40 CFR Part 60, Appendix B.
ii. Compliance with the sulfur dioxide emission standard shall be demonstrated based on a three-hour rolling average of the sulfur dioxide exhaust gas concentration measured by the CEM system.
iii. Pursuant to 15A NCAC 02D .0613 "Quality Assurance Program," the Permittee shall develop and implement a written quality assurance program containing information required by 40CFR Part 60, Appendix F, Section 3, Quality Assurance Procedures.

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

It should be stated that the DAQ has approved the use of dilution cap to demonstrate compliance with the SO_2 emission limit through a letter dated 1/27/20 (Steve Hall, Technical Services Section, DAQ, to Cynthia Winston, Duke Energy) (Steve Hall) with the instruction that the revised permit include the following footnote in the permit:

"The SO_2 monitored value subject to the 0.03 lb/million Btu limit will have a 5% CO_2 diluent cap, or a 14% O_2 diluent cap, substituted in the emission rate calculation whenever the actual CO_2 concentration is lower than 5% or whenever the actual O_2 concentration is higher than 14%."

Based on this DAQ approval, DEC has requested through a letter dated 2/6/20 (Cynthia Winston, DEC, to William Willets, DAQ) that the SO_2 CEMS requirement include the above approved dilution cap language. It should be noted that the DAQ had made a typographical error in describing SO2 limit of 0.03 lb/million Btu, instead of 2.3 lbs/million Btu, under 02D .0516.

In summary, the DAQ will include the requirements to install and operate a CEMS with the use of dilution caps, as above, to comply with the SO_2 limit in 02D .0516.

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 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 that could potentially have significant visible emissions is provided with particulate emissions control. Compliance with this standard is expected using the associated 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. Fugitive dust sources (F-1 through F-6) associated with the STAR® facility will have negligible PM emissions. Compliance is expected.

15A NCAC 02D .1413, Sources Not Otherwise Listed in this Section

The DAQ has earlier determined a RACT of 0.12 lb/million Btu for the STAR® system under the provision of 02D .1413. No change to this determination is warranted as the Permittee continues to apply the same RACT limitation in this application for all NOx-related applicable requirements.

For the new vibratory screener engines (2) and tele-stackers engines (6), the requirements in 02D .1400 do not apply, because, the potential operating hours during May 1 and September 30 (ozone season) for each are less than the respective cut-off values, using the equation in 02D .1402(h) as below:

t = 700,280 / ES where t equals time in hours and ES equals engine size in horsepower.

For vibratory screeners, each 225 HP size,

t = 700,280/225 = 3,703 hours.

As per the application, the potential annual operating hours are 3,120 hour and 2,340 hours, for screener engines 1 and 2, respectively.

Similarly, for tele-stacker engines (6), each 74 HP size, the cut-off value for exemption is 11,261 hours for operating hours during the ozone season. Per the application, the potential annual operating hours are 3,120 hours, 2,340 hours, and 1,560 hours, for engines 1 and 2, 3 and 4, 5 and 6, respectively.

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

NSPS

- As specified in the application review for the current permit, the NCDAQ determined on June 10, 2015[6] that the STAR® reactor would not be subject to CISWI (Commercial and Industrial Waste Incineration) regulations. It concluded 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 when used as an ingredient product in the reactor is considered a non-hazardous secondary material (NHSM) and not a solid waste.

- The requirements in NSPS Subpart IIII apply to the new vibrating screener (2) and tele-stacker (4) engines.

  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.

  The Permittee is expected to comply with all applicable emission limitations, monitoring, recordkeeping and reporting for the above new engines.

NESHAP

- The requirements in NESHAP Subpart ZZZZ apply to the new vibrating screener and tele-stacker engines.

  The facility is a minor source of hazardous air pollutants (HAPs) as its potential emissions (after controls and limitations) after the modification remains less than 10 tons per year for the largest HAP and less than 25 tons per year for total HAPs Minor sources of HAPs are only subject to NESHAPs that apply to area sources.

  Per §63.6590(c), new stationary engine located at an area source, subject to NSPS IIII (or JJJJ), is required to comply with all applicable requirements in NSPS and no other requirements apply under Part 63 for such engines. Thus, the new screener and tele-stacker engines shall comply with the NSPS to comply with the NESHAP requirement.

  Compliance is expected.

PSD

Rowan County has been designated in attainment or unclassifiable/attainment for all promulgated National Ambient Air Quality Standards (NAAQS) per §81.334. Pre-construction permitting requirements (Prevention of Significant Deterioration) apply pursuant to §165 of Clean Air Act (CAA) and 02D .0530 for all major stationary sources and major modifications.

[6] Letter from William Willets, DAQ, to Jim Clayton, The SEFA Group.

DEC's Buck Combined Cycle Facility is an existing "major stationary source", classified under the industrial source category of "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input", in accordance with §51.166(b)(1)(i). The major stationary source threshold for this listed category source is 100 tons/yr of emissions for any regulated NSR pollutants. The facility emits or has potential to emit of 100 tons per year or more for at least one regulated NSR pollutants. In fact, the facility has the potential to emit of more than 100 tons per year for several of criteria pollutants (excluding lead and VOCs (precursor for ozone)) based upon the application.

Thus, any modification to the existing major source, resulting in both the significant emission increases and significant net emissions increase, must be deemed a "major modification", per §51.166(a)(7)(iv)(a). Specifically, a project is a major modification for a regulated NSR pollutant only if it causes two types of emissions increases—a significant emissions increase (as defined in paragraph §51.166 (b)(39) and a significant net emissions increase (as defined in paragraphs §§51.166 (b)(3) and (b)(23)). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

The Permittee has first estimated the project emissions using the actual-to-potential test for all new emissions units to determine whether the project results in significant emissions increase for any regulated NSR pollutants. There are no existing units for the project. Then, the Permittee has performed the source-wide (i.e., facility wide) netting analysis for all increases and decreases in actual emissions, occurring within the reasonable period (7 years from the date the project units start emitting (operating) as defined in 02D .0530) and that are contemporaneous with the change.

The Permittee has used different emissions factors and emission estimation methods, based on the type of source, as discussed in Section 6 above, to estimate emissions rates for various emissions units (comprising of a project). The DAQ has reviewed the emissions factors and emission estimation approach and found them acceptable for permitting.

With regard to facility wide netting analysis, the applicant has included the following modifications (increases and decreases in actual emissions), approved by DAQ within 7 years from the project commence operation date (i.e., when the project sources start emitting), and found them contemporaneous with the coal ash beneficiation project (PSD project) and creditable.

- Hot gas path modification project for combined cycle combustion turbines (ES-11 and ES-12) [03786T30, 9/23/14]

- Reestablishing PSD Avoidance for combined cycle combustion turbines only (ES-11 and ES-12) by removing multi cell cooling tower (ES-13), auxiliary boiler (ES-14), emergency generator (ES-15), and emergency firewater pump (ES-16) from the previously established PSD avoidance limitation. Installation of emergency generator (ES-17EmGen) [03786T31, 2/23/15]

- Installation of diesel-fired ash basin dewatering pump [Approval via 2/6/17 DAQ email]

- Retirement of Boilers 8 and 9 (ES-4 and ES-5) [3/30/13][7]

The DAQ believes that the decreases in emissions for various pollutants, associated with the retirement of coal Boilers 8 and 9 on March 30, 2013, have not been relied on by DAQ to issue any PSD permit previously for the facility. Same is also true with any increases in emissions. Thus, the DAQ agrees with the applicant that they are creditable increases and decreases.

The applicant has used potential to emit emissions rates for each of the contemporaneous emissions increases, taken from either the applications supporting such permits, or the issued permits. For such modifications, at the time, the baseline emissions are zero (as the emissions units were "new" for a particular modification).

[7] As per Clean Air Markets Division (EPA)'s searchable database, available at https://ampd.epa.gov/ampd/.

For contemporaneous emissions decreases, associated with the coal Boilers 8 and 9, the applicant has used the average emissions of the 24-month consecutive period of January 2010 through December 2011 for the pollutants required to be included in the 2nd step of applicability analysis (i.e., netting analysis) to determine creditable decreases. It is DAQ's understanding that the above referenced boilers have contributed to reductions in emissions to meet the system-wide caps (limits), included for both SO_2 and NO_x under the NC's Clean Smokestacks Act (CSA) starting 2007. An air quality permit 03786T19 (05/16/2006) was specifically issued to construct and operate a selective non-catalytic reduction technology (SNCR) on Boilers 8 and 9 for complying with the DEC's CSA obligations for NOx reductions. The application review supporting the above air permit indicates an after-control NOx emission rate of 0.17 lb/million Btu for each, associated with the SNCR installation on each boiler. However, the above referenced permit does not include any legal requirement to meet this emission limit of 0.17 lb/million Btu. Moreover, the Act itself does not prescribe any specific emission limit for these pollutants (NOx, SO_2) to comply with for any coal units owned/operated by DEC or DEP (Duke Energy Progress). Thus, DAQ concludes that DEC was not required to meet the NOx emission rate of 0.17 lb/million Btu for boilers 8 or 9 during the selected baseline period.

But, the boilers were required to comply with the emissions limits of 1.63 lbs/million Btu for SO_2 (02D .0501(c)), 1.8 lb/million Btu (coal) and 0.8 lb/million Btu (fuel oil), both for NOx (02D .0519), and 0.15 lb/million Btu/hr for PM (02D .0536), as per the air permits, effective during the selected baseline period.

The Attachment 1 spreadsheet (to this document), prepared using the data retrieved from EPA's Clean Air Markets Division's database, includes the average SO_2 and NOx emissions rates for 2010-2011 period of 1.13 lb/million Btu and 0.19 lb/million Btu, respectively. Moreover, using the DAQ's emissions inventory for each of these years, the average emission rate for PM during the baseline period was approximately 0.069 lb/million Btu, taking into account the average heat input rate of 8,370,802 million Btu and average PM emissions of 290.26 tons per year, both for Boilers 8 and 9. Thus, no adjustments in the baseline emissions are required per 02D .0530(a)(1) for each of these pollutants (SO_2, NOx, and PM), and the entire amount of baseline emissions for each pollutant, as included in the application, are deemed creditable decreases.

With regard to the provision in §51.166(b)(3)(vi) on extent of creditability of decreases in actual emissions for PSD netting, considering the "same qualitative significance for public health and welfare" as that attributed to the increase from the project, it needs to be noted that the DAQ had approved a modeling analysis for the initial design (T35 air permit, May 10, 2018), concluding that the facility-wide emissions including the STAR® facility emissions do not cause or contribute to violation of either 1-hour NO_2 or 1-hour SO_2 NAAQS.

With the redesigned project, emissions of both NOx and SO_2 across individual project sources are either remaining the same or decreasing, as compared to the initial design approval. In addition, the total project emissions are decreasing for both NOx and SO_2. Consider for NOx, 117.66 TPY total emissions (initial design) v. 79.17 TPY (redesign). Similarly, for SO_2, 163.87 TPY v. 97.81 TPY. Moreover, the stack parameters for the STAR® system are improving such that the overall dispersion will increase; thereby, decreases in the ambient air impacts for the facility-wide source emissions are expected with respect to the referenced NAAQSs. In summary, the DAQ expects that the redesign project will not cause or contribute to the violation of 1-hour NO_2 or 1-hour SO_2 NAAQSs.

In summary, even though the project (i.e., the redesigned coal beneficiation project) emissions are higher than the applicable significance thresholds for several pollutants (Step 1), the project does not trigger significance net emission increase (Step 2) for any regulated NSR pollutant; thus, the project has been deemed not a major modification and the applicant is not required to obtain a PSD permit.

Tables 8-1 and 8-2 below include the project emissions (Step 1) and the netting analysis (Step 2), respectively:

Table 8-1 Project Emissions

Pollutant	Emissions Tons/Yr	Significant Emission Rate Tons/Yr	Netting Required?
PM	108.21	25	Yes
PM10	97.54	15	Yes

Pollutant	Emissions Tons/Yr	Significant Emission Rate Tons/Yr	Netting Required?
PM2.5	24.64	10	Yes
SO_2	97.81	40	Yes
NOx	79.17	40	Yes
CO	96.41	100	No
VOC	11.28	40	No
Lead	0.014	0.6	No
H_2SO_4 mist	0.44	7	No
GHG as CO2e	117,704	75,000	Yes

Table 8.2 Netting Analysis

Description of Emissions	NO_X (TPY)	SO_2 (TPY)	PM (TPY)	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	CO2e (TPY)	Unit Operation/Retired date	Notes
STAR Facility Emissions (Increases)	79.17	97.81	108.21	97.54	24.64	117,704	Expected operation to begin after May 2018	Emissions Calcs dated 020819 (NOx at 0.12 lb/MMBtu).
PSD Avoidance Cap for ES11 and ES12 (Increases)	599.8		198.90	160.8			Unit 11 began operation - 9/25/2011 and Unit 12 - 10/3/2011 (PSD Avoidance limits)	Permit No. 03786T35, 2.1-A.6.a (NO_X, PM, PM_{10}).
ES11 and ES12 (Increases)		108.52			160.8	2,669,078		Application BK Hot gas path mod Table A-4 dated May 7, 2014 (SO_2). Duct Burner Modification Application Table 3-2 dated Feb 15 2013 (CO2e). $PM_{2.5}$ assumed to equal the PM_{10} avoidance cap.
ES13 - 10 cell cooling tower (Increases)			7	7	7		November 2011 (Potential to Emit)	Application Hot gas path mod Table A-7 dated May 7, 2014. $PM_{2.5}$ assumed to equal PM_{10}.
ES14 - Auxiliary Boiler, 36.74 MMBtu/hr (Increases)	1.8	0.22	0.40	0.4	0.4		November 2011 (Potential to Emit)	
ES15 - Fuel oil fired emergency generator (1490 hp) (Increases)	0.8	0.0009	0.028	0.023	0.023		November 2011 (Potential to Emit)	
ES16 - Fuel oil fired fire water pump (237 hp) (Increases)	0.1	0.0001	0.004	0.004	0.004		November 2011 (Potential to Emit)	
ES72 - Chiller cooling tower (Increases)			0.60	0.6	0.6		June 2012 (Potential to Emit)	
Ash Basin Water Management Pump (Increases)	2.5	0.004	0.016	0.016	0.016		Unit added- February 2017 (Potential to Emit)	Letter to DAQ submitted on Feb 2, 2017 for addition of 55 kw diesel fired engine pump along with emissions calculation file.
ES17 - Fuel Oil fired emergency generator (762 hp) (Increases)	0.513	0.0005	0.003	0.002	0.002		Unit added- February 2015 (Potential to Emit)	Application BK ES-17EmGen Application dated May 18, 2016.
Total Increases	**684.68**	**206.56**	**315.16**	**266.39**	**193.49**	**2,786,782**		
Contemporaneous Emission Decreases (Unit 5, Blr 8), 2010	447.80	2,833.80	143.13	127.69	109.86		Units retired - 4/1/2013	NC DAQ Actual Emissions Inventory 2010 (Unit 5, Blr 8).
Contemporaneous Emission Decreases (Unit 6, Blr 9), 2010	476.60	2,776.10	156.16	134.61	109.88			NC DAQ Actual Emissions Inventory 2010 (Unit 6, Blr 9).
Contemporaneous Emission Decreases (Unit 5, Blr 8), 2011	305.80	1,931.50	160.30	140.87	118.54			NC DAQ Actual Emissions Inventory 2011 (Unit 5, Blr 8).
Contemporaneous Emission Decreases (Unit 6, Blr 9), 2011	333.20	1,907.50	120.93	112.70	103.39			NC DAQ Actual Emissions Inventory 2011 (Unit 6, Blr 9).
Contemporaneous Emission Decreases Avg 2010-2011	**781.70**	**4724.45**	**290.26**	**257.94**	**220.84**			Average actual emissions from 2010 and 2011.
PSD SERs	40	40	25	15	10	75,000		
Difference	**-97.02**	**-4517.89**	**24.90**	**8.45**	**-27.35**	**2,786,782**		
Significant Modification (Yes/No)	**No**	**No**	**No**	**No**	**No**	**Yes**		

Based upon the applicability analysis, the Permittee must start operating the project emission sources on or before March 30, 2020, as the 7-year reasonable period runs out for the creditable emission decreases, resulting from the retirement of Boilers 8 and 9 on March 30, 2020. The Permittee had stated through a letter dated August 31, 2017 (Dan Markley, Duke Energy Carolinas, to William Willets, Division of Air Quality), at the time of processing the application for initial coal ash beneficiation project permit (03786T35, May 10, 2018), that it had commenced operation of the diesel-fired ash basin dewatering pump (55 kw), which is used solely to dewater the ash basin, so that the coal ash can be excavated and processed in the STAR® facility. The source has been described as "ash basin water management pump" by the applicant in Table 8-2 above. Thus, the facility implied that the STAR® project had already commenced operation. The DAQ had issued on February 17, 2017 applicability determination via email, concluding that the referenced source was an insignificant activity and no permit modification was required at the time. Even though the facility categorized in the netting analysis the installation of ash basin dewatering as a creditable increase, it appears to be part of a single project (coal ash beneficiation). Based on the aggregation rule[8], the DAQ believes that a substantial relationship exists between the ash basin dewatering pump and the STAR® facility sources, based on technical standpoint; thus, they need to be treated as a single project. Thus, DAQ believes that the applicant

[8] "Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR):Aggregation; Reconsideration", 83 FR 57324, November 15, 2018.

has protected the creditable reductions of retired Boilers 8 and 9 and satisfied the netting provision requirements, ensuring the STAR® project "minor" for permitting.

Finally, although the project even after the redesign remains "minor", it needs to be specified that the applicant has used various restrictions to limit the emissions increase from the project (such as PM increase of 24.90 tons/yr) to less than the significance level of 25 tons/yr. The DAQ will include all such restrictions as described below to limit the PM emissions to less than 25 tons/yr, making the permit stipulation under 02Q .0317 federally enforceable (enforceable as a practical matter):

Operating Restrictions

- 8,520 hours of operation per consecutive 12-months period, each for STAR®, External Heat Exchangers, and Ball Mill Classifier
- Fly ash processing rates of 130 million Btu/hr (annual average) and 400,00 tons (annual maximum) for STAR® system
- Unloading pile working area of 0.33 acre
- Ash basin working area of 25 acres
- Truck-loads of 17,200 per consecutive 12-months period, each way, to and from the ash basin
- Truck driving distance of 1.1 mile each way, to and from ash basin
- Hours of operation of 3,120 and 2,340 per consecutive 12-months period for screener 1 and 2, respectively
- Hours of operation of 3,120 and 2,340 per consecutive 12-months period for screener engines 1 and 2, respectively
- Hours of operation of 3,120, 2,340, and 1,560 per consecutive 12-months period for tele-stackers 1 and 2, 3 and 4, and 5 and 6, respectively
- Hours of operation of 3,120, 2,340, and 1,560 per consecutive 12-months period for tele-stacker engines 1 and 2, 3 and 4, and 5 and 6, respectively

Testing

- The Permittee will conduct a stack test to determine emission factor for particulate matter (lb of emissions per ton of coal ash processed) for STAR® system (ID No. ES-74) for both natural gas and propane firing scenarios, within six months of its initial start-up.
- The Permittee will conduct periodic stack tests at least once every five years (not more than 61 months from the previous stack test) to reestablish the emission factor for particulate matter (lb of emissions per ton of coal ash processed) for STAR® system (ID No. ES-74) for both natural gas and propane firing scenarios.

Monitoring/Recordkeeping

- The Permittee will be required to keep records (written or electronic format) on a monthly basis for actual coal ash processing rates for STAR® system (ID No. ES-74) in the units of both million Btu/hr and tons. The Permittee will determine both annual average (million Btu/hr) and annual maximum (tons) coal ash processing rates for each month of the consecutive 12-months period.
- The Permittee will be required to keep records (written or electronic format) of hours of operation on a monthly basis and total them for each of the consecutive 12-months period, for STAR® system (ID No. ES-74), two external heat exchangers (ID Nos. ES-77 and ES-78), and Ball mill classifier (ID No. ES-84),

- The Permittee will calculate particulate emissions at the end of each month, for all STAR® sources, using the emissions factor developed via stack testing as discussed above, and default emission rates specified below:

  PM emissions, tons/month =

  {{[emission factor (lb/ton) for STAR® system (ES-74) * amount of coal ash processed (tons/month)] + [6.86 lb particulates/hr for two external heat exchangers (ES-77 and ES-78) * total hours of operation (hours/month)] + [0.78 lb particulates/hr for Ball mill classifier (ES-84) * hours of operation (hours/month)]} / 2000} + {default total emission rate (ton/month) for STAR® facility ancillary sources}

  Where,

  Default total emission rate for STAR® facility ancillary sources (ID Nos. ES-73, ES-75, ES-76, ES-79, ES-80, ES-81, ES-81A, ES-81B, ES-82A1, ES-82A2, ES-82B1, ES-82B2, ES-82C1 through ES-82C6, ES-82D1 through ES-82D6, ES-85, ES-86, and ES-F1 through ES-F6) = 0.41 ton/month

  The emissions rates of 6.86 lb/hr (29.21 tons/yr) total for two EHEs and 0.78 lb/hr (3.33 ton/yr) for Ball mill classifier have been taken from the application. Similarly, the default emission rate for all other sources (other than STAR®, two EHEs, and Ball mill classifier) of 0.41 ton/month (4.92 tons/yr) is taken from the application.

  Until the Permittee determines the actual emission factor for particulate matter for STAR® system (ES-74), through the stack testing, the Permittee shall use an emission factor of 16.61 lbs/hr (application) along with the actual operating hours recorded to determine monthly particulate emissions for this source.

  The Permittee will be required to keep the records for amounts of particulate matter emissions for each of the sources in a logbook (written or electronic format) and total emissions for each consecutive 12-months period, using the emissions for the current month and the previous 11-months period.

Reporting

- The Permittee will submit the actual coal ash processing rates for STAR® system (ID No. ES-74 and the actual hours of operation for STAR® system (ID No. ES-74), two external heat exchangers (ID Nos. ES-77 and ES-78), within 30 days of receipt of a written request by the DAQ.

- The Permittee will submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

- The Permittee will submit a complete permit application for including the emissions factor in the air quality permit, as established through stack testing (discussed previously), before the close of business on the 60th day following the completion of the performance test.

<u>112(r)</u>

- 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 or concentrations above the applicable thresholds in the Rule. This permit modification does not affect the 112(r) status.

<u>CAM</u>

- The current permit includes a CAM plan for SO_2 emissions from the STAR® system for the emission standard in 02D .0516 (2.3 lb/million Btu). As stated above, the applicant has proposed to install a SO_2 CEMS; thus, it requested to remove the CAM plan from the permit.

Per §64.2(b)(1)(vi), if the source is subject to an emission limitation or standard for which a permit issued under 15A NCAC 02Q .0500 specifies a continuous compliance determination method, as defined in 40 CFR 64.1, it is exempt from the requirements of CAM.

With the revised permit, the Permittee will be required to install and monitor SO_2 emissions using the CEMS; thus, CAM requirements become non-applicable and they will be removed from the permit.

9. Facility-wide Air Toxics

As stated above, the facility had obtained an air permit for the coal ash beneficiation project, as submitted at the time, complying with the Acceptable Ambient Levels (AALs) for various pollutants (arsenic, benzene, beryllium, cadmium, chromium VI (soluble chromate), formaldehyde, non-specific chromium VI compounds, as chromium VI equivalent, mercury, nickel metal, and sulfuric acid mist). The permit includes the approved emissions limits for these pollutants on a source-by-source.

With the redesign of the coal ash beneficiation project, net increases in emissions are expected. Table 9-1 below provides a comparison of the facility wide potential emissions for the redesigned coal ash project, considering limitations discussed above, with the applicable Toxic Pollutant Emission Rates (TPERs) in 02Q .0711. It should be noted that the facility-wide emissions do not include the emissions from the exempt sources, such as NESHAP-subject screener engines (ES-82B1 and ES-82B2) and tele-stacker engines (ES-82D1 through ES-D6), pursuant to 02Q .0702(a)(27).

It should also be noted that in the facility-wide emissions v. TPERs evaluation, the Permittee has excluded chromium VI emissions for two natural gas fired combined cycle combustion turbines. The Permittee contends that there are no chromium (VI) emissions due to combustion of natural gas in these combustion turbines[9]. Further, the Permittee states that the DAQ spreadsheet for natural gas combustion (developed based on Section 1.4 "Natural Gas Combustion", AP-42) only calculates metallic emissions from the combustion of natural gas if the user selects that the boiler also burns coal or No. 2 fuel oil. This is due to information in the Background Information Document for Section 1.4 of AP-42 that states that the metallic emissions from natural gas combustion were measured from a dual-fuel fired source. However, the Buck facility combustion turbines fire exclusively natural gas. In summary, DAQ agrees with the applicant that no chromium VI emissions are expected from natural gas only - fired combined cycle units at the facility.

Thus, the applicant is required to submit a modeling analysis for arsenic, benzene, beryllium, cadmium, formaldehyde, mercury, nickel, and sulfuric acid (both 1-hour and 24-hour averaging periods), pursuant to Table 9-1. The applicant has modeled the following emissions rates for the pollutants, which are optimized rates of the potential rates, corresponding to 98 percent of applicable AALs. The ratio of potential to optimized emissions rates range between 0.00023 (mercury) to 0.14 (arsenic). Thus, no monitoring including record keeping for approved emissions rates can be justified for any pollutants. Table 9-2 below includes the optimized rates for approval.

It should be noted that based on DAQ's recommendation, the DEC has revised the emissions rates for various air toxics for the receiving pile (F-3) and ash basin (F-4), using the approach advocated by EPA[10], instead of AP-42 emission estimation method[11]. This EPA-recommended method is also discussed in the "WRAP Fugitive Dust Handbook (September 7, 2006)"[12]. The DAQ recommended the above approach, which is more representative for the use of average hourly wind speed (instead of wind gust speed) and was previously recommended by the agency for other modifications involving storage piles. e.g., Duke Marshall application (March 2019). This methodology applies to active (i.e., frequently disturbed) storage piles and relies on, among other inputs, the percentage of time the windspeed is greater than 12 miles per hour. The emission calculations for storage piles (receiving pile and ash basin)

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[9] Section 3.1 "Stationary Gas Turbines, 4/00 and Section 1.4, Natural Gas Combustion, 7/98, AP-42.
[10] Table 21, "Emission Factor (EF) Equations for Soils Handling (Total Suspended Particulate)", *Air/Superfund National Technical Guideline Study Series, Volume III - Estimation of Air Emissions from Cleanup Activities at Superfund Sites, Interim Final*, EPA-450/1-89-003, January 1989.
[11] Section 13.2.5 "Industrial Wind Erosion", 11/06.
[12] Section 9.3 "Emission Estimation: Alternate Methodology", Chapter 9, Storage Pile Erosion.

were also updated to include the site-specific ash analysis data (instead of default ash concentration data from EPRI previously used). The applicant has applied control efficiencies with the use of various engineering controls (e.g., 95% for ash storage enclosure, 75% for inactive undisturbed area, 90% for routine application for chemical binding, 88% for routine truck wetting, 85% for measures described in CCR, 75% inherent moisture content, etc.). DEC has supported the use of specific control efficiencies with the information as below:

> Emissions of PM, PM10 and PM2.5 were calculated using an overly conservative emissions estimation methodology for storage piles from EPA and the Western Regional Air Partnership (WRAP) handbook. This methodology applies to active (i.e., frequently disturbed) storage piles and relies on, among other inputs, the percentage of time the windspeed is greater than 12 miles per hour. Personnel are routinely observing the basins and ensuring that fugitive emissions are minimized at all time in accordance with North Carolina and Federal regulations. Each site operates under a Fugitive Dust Control Plan in accordance with 40 CFR §257.80 and Duke Energy must provide periodic reports under the CCR rule detailing any observed dusting events or offsite complaints that are received.
>
> See the following link for additional information on the Fugitive Dust Plan and all control measures that are implemented or available for implementation should they be required: LINK **[duke-energy.com]**
>
> The following link contains the 2019 Annual report for the Buck facility detailing no complaints received and no corrective actions were required. LINK [duke-energy.com]
>
> Based on these facts, many of the estimated control efficiencies are the result of engineering judgement. As mentioned previously, the ash receiving area is a three-sided enclosure which will significantly minimize the potential for windblown emissions from the storage pile. The WRAP methodology is applicable to active storage piles resulting in an overestimate of emissions for inactive portions of the Ash Basin. This is because there is only a finite availability of erodible material and once a wind event has occurred, the potential for additional emissions is not restored until the surface material is disturbed again. Much of the Ash Basin will be undisturbed and inactive after the initial clearing of trees, plants, and ground cover; thus, the high ratio of inactive to active area, combined with the use of the WRAP methodology, results in an unnecessarily overly conservative emissions estimate. Therefore, Duke Energy has developed the emissions calculations and control efficiency assumptions for the inactive portion of the storage pile to reflect additional control accounting for the infrequent disturbance of the inactive area. On top of the infrequent disturbance, a control efficiency for natural crusting was applied, and the control efficiency for routine watering has also been updated to reflect the improved control achieved using a chemical binding agent (a liquid copolymer) that may be applied to the surface layer. Finally, the moisture content of the ash when first harvested is greater than 50% and there is no potential for emissions, the material must go through a drying process over an extended period of time to dewater and even reach a point where emissions could be expected to occur if not for the control measures.

With the above updates, the emissions of metallic compounds did increase slightly over those presented in the application for both receiving pile and ash basin; however, the emissions rates are still below the optimized emission rates that were requested in the application.

The DAQ has reviewed the emissions rates estimation methods and emissions factors for each of the sources and found them representative. The Air Quality Analysis Branch (AQAB) of Permitting Section has reviewed the submitted modeling demonstration and concluded on 10/1/19 that the "modeling adequately demonstrates compliance on a source-by-source basis. Table 9-3 below memorializes the predicted impacts for the optimized emissions rates.

Table 9-1 TPER Analysis

Pollutants	Existing Turbine ES-11			Existing Turbine ES-12			Existing Auxiliary Boiler			Existing Auxiliary Equipment			STAR Facility			Total			TPER			Modeling Required?		
	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr
Sulfuric Acid Mist	**1.7**	40.8		**1.7**	40.8								1.00E-01	2.40		3.50	84.00		0.025	0.25		**YES**	**YES**	
Benzene			**220**			**220**			**0.206**	1.38E-02	3.31E-01	1.38E+00			15.89			457.47			8.1			**YES**
Formaldehyde	**4.46E-01**			**4.46E-01**			**0.00368**			3.20E-03	7.68E-02	3.20E-01	1.18E-02			0.91			0.04			**YES**		
Hexane		3.94E+00			3.94E+00			2.12E+00						2.54			12.54			23.0			NO	
Toluene	1.29E-01	3.10E+01		1.29E-01	3.10E+01		1.64E-04	3.94E-03		4.74E-03	1.14E-01	4.74E-01	2.76E-03	6.62E-02		0.27	62.18		14.4	98.0		NO	NO	
Arsenic			**4.48**			**4.48**			**0.0196**	6.97E-05	1.67E-03	6.97E-03			26.03			35.02			0.053			**YES**
Beryllium			**0.27**			**0.27**			**0.00118**	5.23E-05	1.25E-03	5.23E-03			5.38			5.92			0.28			**YES**
Cadmium			**24.6**			**24.6**			**0.108**	5.23E-05	1.25E-03	5.23E-03			5.19			54.51			0.37			**YES**
Soluble chromate compounds as Chromium VI equivalent														9.78E-03			0.010			0.013			NO	
Manganese		**2.33E-02**			**2.33E-02**			**4.47E-04**		1.05E-04	2.51E-03	1.05E-02		1.57E-01			0.207			0.630			NO	
Mercury		**9.86E-03**			**9.86E-03**			**3.05E-04**		5.23E-05	1.25E-03	5.23E-03		8.37E-04			0.022			0.013			**YES**	
Nickel		**1.29E-01**			**1.29E-01**			**2.47E-03**		5.23E-05	1.25E-03	5.23E-03		9.19E-02			0.354			0.013			**YES**	

Table 9-2 Approved Emissions Limits

ID	Arsenic lb/hr	Benzene lb/hr	Beryllium lb/hr	Cadmium lb/hr	Formaldehyde lb/hr	Mercury lb/hr	Nickel lb/hr	Sulfuric Acid lb/hr 1-hour	Sulfuric Acid lb/hr 24-HR
EP11	3.40E-03	1.19E+01	1.93E-03	2.30E-01	2.65E+02	1.86E+00	5.54E-01	1.81E+02	4.21E+01
EP12	3.40E-03	1.19E+01	1.93E-03	2.30E-01	2.65E+02	1.86E+00	5.54E-01	1.81E+02	4.21E+01
EP14	1.49E-05	1.11E-02	8.42E-06	1.01E-03	2.19E+00	5.75E-02	1.06E-02		
EP73	3.51E-06		6.84E-06	7.74E-06		3.36E-05	1.45E-04		
EP74	1.32E-02	5.83E-02	2.55E-02	3.41E-02	2.63E+00	1.26E-01	2.59E-01	1.07E+01	2.48E+00
EP77	5.40E-03		1.05E-02	1.19E-02		2.36E-02	1.02E-01		
EP78	5.40E-03		1.05E-02	1.19E-02		2.36E-02	1.02E-01		
EP79	3.51E-06		6.84E-06	7.74E-06		3.36E-05	1.45E-04		
EP80	3.51E-06		6.84E-06	7.74E-06		5.88E-05	2.53E-04		
EP81	1.75E-06		3.42E-06	3.87E-06		5.04E-05	2.17E-04		
EP81A	8.77E-07		1.71E-06	1.93E-06		1.68E-05	7.24E-05		
EP81B	8.77E-07		1.71E-06	1.93E-06		1.68E-05	7.24E-05		
EP84	6.16E-04		1.20E-03	1.36E-03		2.69E-03	1.16E-02		
EP85	3.90E-10		7.61E-10	8.61E-10		5.04E-06	2.17E-05		
F1	1.30E-06		2.54E-06	2.88E-06		8.74E-06	3.77E-05		
F2	2.61E-06		5.09E-06	5.75E-06		1.75E-05	7.53E-05		
F3	1.62E-06		3.16E-06	3.58E-06		7.09E-06	3.06E-05		
F4	5.48E-04		1.07E-03	1.21E-03		4.90E-03	2.11E-02		

Table 9-3 Predicted Impacts

Pollutant	Averaging Period	Max. Concentration ($\mu g/m^3$)	AAL ($\mu g/m^3$)	% of AAL
Arsenic	Annual	2.06E-3	2.1E-3	98 %
Benzene	Annual	0.118	0.12	98 %
Beryllium	Annual	4.0E-3	4.1E-3	98 %
Cadmium	Annual	5.41E-3	5.5E-3	98 %
Formaldehyde	1-hour	146.71	150	98 %
Sulfuric Acid	1-hour	97.87	100	98 %
	24-hour	11.73	12	98 %
Mercury	24-hour	0.59	0.6	98 %
Nickel	24-hour	0.59	0.6	98 %

Finally, North Carolina Division of Air Quality's air toxics program is a "risk-based" regulatory program designed to protect the public health by limiting emissions of toxic air pollutants from man-made sources. As stated above, the modeling analysis demonstrated compliance on a source-by-source basis with the AALs at 98 percent of the applicable AALs. Further, the ratio of potential to optimized rates ranges between 0.00023 (mercury) to 0.14 (arsenic). Thus, the DAQ has concluded that the emissions from the exempt Part 63 affected sources, such as NESHAP-subject engines (screener and tele-stacker engines, and ash basin dewatering pump) are not expected to present an unacceptable risk to human health.

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

This application is processed pursuant to 15A NCAC 02Q .0501(b)(2) (1st step of 2-step process); therefore, no public noticing or hearing is required.

11. Stipulation Review

The following Table 11-1 includes changes which were made to the Duke Energy Carolinas, LLC – Buck Combined Cycle Facility's Air Quality Permit No. 03786T35:

Table 11-1 Summary of Changes to Current Permit

Old Page Air Quality Permit No. 03786T35	**Old Section** Air Quality Permit No. 03786T35	**New Page** Air Quality Permit No. 03786T36	**New Section** Air Quality Permit No. 03786T36	**Description of Change(s)**
Cover				Amended permit numbers and dates. Included increment tracking statement.
Insignificant Activities List				Removed I-F1 through I-F6 and moved them in Section I Table.
5	Section I Table	6	Section I Table	Included ES-F1 through ES-F6 (moved from the insignificant activity list). Included new sources and control devices: ES-82A1, ES-82A2, ES-82B1, ES-82B2, ES-82C1 through ES-82C6, ES-82D1 through ES-82D6, ES-84, CD-84, ES-85, CD-85, and ES-86. Included a footnote for control equipment **(**ID Nos. CD-73, CD-75, CD-76, CD-77, CD-78, CD-79, CD-80, CD-81, CD-81A, CD-81B, CD-84, and CD-85) to indicate that they are non-optional integral part of the process equipment as originally designed and manufactured by the equipment supplier.
21	Section 2.1.D., Section 2.1.D. Table	19	Section 2.1.D, Section 2.1.D. Table	Removed references for screener engine (ES-82B) and crusher engine (ES-83B) everywhere in Section 2.1.D. Removed non-applicable requirement in 02D.0516 as sources subject to NSPS (02D .0524) are not covered under 02D .0516 regulation.
23	Section 2.1.D.3.i.	20	Section 2.1.D.2.i.	Included the most current requirement under NSPS IIII for emergency engines.
24	Section 2.1.D.4.a.	22	Section 2.1.D.3.a.	Rewrote this stipulation to make it clear that no requirement under Part 63 shall apply (not just the Subpart ZZZZ) as long as the Permittee complies with the applicable NSPS Subpart IIII.
25	Section 2.1.E. Table	22	Section 2.1.E. Table	Removed non-applicable requirement in 02D.0516 as sources subject to NSPS (02D .0524) are not covered under 02D .0516 regulation.
26	Section	24	Section	Included the most current requirement under NSPS IIII for

Old Page Air Quality Permit No. 03786T35	**Old Section** Air Quality Permit No. 03786T35	**New Page** Air Quality Permit No. 03786T36	**New Section** Air Quality Permit No. 03786T36	**Description of Change(s)**
	2.1.E.3.i.		2.1.E.2.i.	emergency engines.
28	Section 2.1.E.4.a.	25	Section 2.1.E.3.a.	Rewrote this stipulation to make it clear that no requirement under Part 63 shall apply (not just the Subpart ZZZZ) as long as the Permittee complies with the applicable NSPS Subpart IIII.
28	Section 2.1.F.	25	Section 2.1.F.	Throughout this section, removed non-compliance statements, and replace the citation of 02Q .0508(f) with 02Q .0308(a) for basis of terms. In addition, removed a statement of reporting of instances of deviations. All these requirements, statements, and basis are not appropriate under the 02Q .0300 program.
28	Section 2.1.F.Table	25	Section 2.1.F.Table	Removed a non-applicable CAM requirement. Include applicable requirements under 02Q .0317 (PSD Avoidance) and 02Q.0504.
29	Section 2.1.F.2.c.	26	Section 2.1.F.2.c. through f.	Included SO_2 monitoring requirement using CEMS.
30	Section 2.1.F.4.	-	-	Removed a non-applicable CAM requirement.
32	Section 2.1.G.	28	Section 2.1.G.	Throughout this section, included new sources and control devices: ES-82A1, ES-82A2, ES-82B1, ES-82B2, ES-82C1 through ES-82C6, ES-82D1 through ES-82D6, ES-84, CD-84, ES-85, CD-85, and ES-86. Throughout this section, removed non-compliance statements, and replace the citation of 02Q .0508(f) with 02Q .0308(a) for basis of terms. In addition, removed statements of reporting of instances of deviations. All these requirements, statements, and basis are not appropriate under the 02Q .0300 program.
32	Section 2.1.G. Table	28	Section 2.1.G. Table	Included applicable requirements under 02Q .0317 (PSD Avoidance) and 02Q.0504.
-	-	30-32	Section 2.1.H.	Added this new section for two screener engines, six tele-stacker engines, and one ash basin dewatering pump. Added applicable requirements table for 02D .0516, .0524, .1111, and 02Q .0317 and .0504. Included substantive requirements for 02D .0516 and .0524 (NSPS).
-	-	32-34	Section 2.1.I.	Included sources ES-F1 through ES-F6 with table of applicable requirements in 02D .0540 and .1100, and 02Q .0317, .0504, and .0711. Included substantive requirements under 02D.0540.
35-38	Section 2.2.A.1. and 2.	35-37	Section 2.2.A.1. and 2.	Included approved emissions rates for all modeled toxics and pollutants which did not exceed the applicable TPERs.

Old Page Air Quality Permit No. 03786T35	**Old Section** Air Quality Permit No. 03786T35	**New Page** Air Quality Permit No. 03786T36	**New Section** Air Quality Permit No. 03786T36	**Description of Change(s)**
-	-	38	Section 2.2.B.	Included all STAR® facility sources as per the redesign and table for applicable requirements under 02Q .0317 (PSD Avoidance) for PM emissions.
-	-	38	Section 2.2.B.1.	Included all requirements pursuant to PSD avoidance for the STAR® project.
-	-	40	Section 2.2.B.2.	Included a requirement to submit a TV application under 02Q .0504 (2nd step of two-step process) within 12-months of commencement of operation of any STAR® project source.
40-50	Section 3	42-50	Section 3	Updated the existing General Conditions with its current version 5.3, 08/21/2018, using the DAQ's TV permit shell.

12. Conclusions, Comments, and Recommendations

- A professional engineer's seal was required for the changes requested in this application. Mr. Thomas Pritcher, P.E. License No. 025453 sealed the application Appendix A (Air Permit Application Forms) and B (Supporting Emission Calculations), pursuant to 15A NCAC 02Q .0112, on July 1, 2019. A search of the registrant directory on the N.C. Board of Examiners for Engineers and Surveyors website confirmed that Mr. Pritcher's license to practice engineering in the state is in the "current" (active) status.

- The DAQ has determined that the changes processed in this application including new sources do not constitute an expansion of the existing facility.

- The draft permit was emailed to the Permittee on March 27, 2020 for review. Dan Markley (DEC) emailed on April 3rd with one comment on incorrect emission rate of nickel for combustion turbines ES-11 and ES-12: 13.30 lb/day instead of 132.96 lb/day in Section 2.2. A.1.a. This correction will be made in the final permit.

- The draft permit was emailed to the MRO on March 27, 2020 for review. Jim VanWormer emailed on April 3rd indicating that the source ES-17 can be removed from the permit as it has been removed from the facility in Fall 2018. The DAQ has determined that it will remove this source from the permit at the time of PSD application processing (currently being done) for the separate "solar influx" project.

This permit engineer recommends issuing the final permit.

Attachment 1 [to Review of Application 8000004.19A]

This document was a spreadsheet prepared using data retrieved from EPA's Clean Air Markets Division's database. It was attached to the physical copy of the review of application 8000004.19A but not included in the electronic record.

Attachment 3 to Review of Applications 8000004.20A, .20B, & .21A
Duke Energy Carolinas, LLC - Buck Combined Cycle Facility:
Fire Retardant Additives and Updated NHSM Determination

DEC submitted a request to include fire retardant additives with the flyash processed by the STAR system. DEC also submitted information to show that the flyash will still qualify as an NHSM.

1. *Initial request for fire retardant additives:*

DUKE ENERGY®

Duke Energy Carolinas, LLC
Buck Combined Cycle Combustion Turbine Facility
1385 Dukeville Road
Salisbury, NC 28146-8613

May 18, 2021

Mr. Russell Braswell
North Carolina Department of Environmental Quality
Division of Air Quality
1641 Mail Service Center
Raleigh, North Carolina 27699-1641

Subject: **Draft Air Permit Number 03786T37 Comments**
Duke Energy Carolinas, LLC
Buck Combined Cycle Facility
Salisbury, Rowan County, North Carolina
Facility ID: 8000004; Air Permit No. 03786T36

Dear Mr. Braswell,

Duke Energy appreciates the opportunity and time to review the Buck Combined Cycle draft air permit number 03786T37. With our review, we have no comments on what was drafted for us. We are however requesting additional wording to the permit concerning the STAR® ash beneficiation facility.

Over the past few months, Buck has struggled operationally with fires in the External Heat Exchangers. This causes us to shut down the process and clean out the clinkers created by these fires. It has also caused damage to the tube bundles requiring extended outage time for repair. In order to alleviate this situation, we are proposing to add material to the feedstock ash to improve the fluidization of the ash (to eliminate hot spots as the flyash clumps) and to add a level of fire resistance to the flyash. These potential additives will not contain any toxic chemicals and will not affect our emissions. Three of the potential additives are "Flame Freeze Wetting Agent", "Flowtrol 195", and "CoalTrol F430". Off-site lab-scale testing of these materials is being planned. Their Safety Data Sheets are attached for reference.

The current permit references the feedstock to the STAR® system as "fly ash and other ingredient materials". We would like to add a footnote to clarify that this may include fire prevention materials.

The proposed language in the permit is as follows, from the Section 1 – PERMITTED EMISSION SOURCE(S) AND ASSOCIATED AIR POLLUTION CONTROL DEVICE(S) table:

Page No(s)	Emission Source I.D. No.	Emission Source Description	Control Device I.D. No.	Control Device Description
	ES-74 **(RACT)**	STAR® (Staged Turbulent Air Reactor) system with 140 million Btu per hour maximum firing rate and not to exceed 400,000 tons per year processing rate for feedstock (fly ash and other ingredient materials[3]) into commercial products, and equipped with natural gas/propane low-NOx start-up burners (60 million Btu per hour total maximum capacity) for use during start-up or when necessary to maintain the desired reactor temperature; an integral cyclone and baghouse for product recovery	CD-74A CD-74B	Dry flue-gas desulfurization (FGD) scrubber with a to be determined minimum lime-to-sulfur ratio Bagfilter with a maximum 2.18 to 1 air to cloth ratio

[1] Applicable to combined-cycle operation only

[2] Non-optional air pollution control equipment that constitutes an integral part of the process equipment as originally designed and manufactured by the equipment supplier.

[3] May include emissions-neutral flyash additives to improve system performance (i.e. flame retardants).

Thank you for your consideration of this change to the draft permit. Should you have any questions or concerns regarding this, please contact Dan Markley at (704) 816-9164 or Dan.Markley@duke-energy.com.

Respectfully submitted,

Daniel Markley

Daniel Markley, P.E.
Duke Energy, Permitting and Compliance, Carolinas

Attachment – Three (3) Safety Data Sheets

Cc: Mr. Kris Eisenrieth, General Manager, Buck Combined Cycle

2. *Updated NHSM determination:*

From: Markley, Dan <Dan.Markley@duke-energy.com>
Sent: Tuesday, July 27, 2021 7:41 AM
To: Braswell, Russell <russell.braswell@ncdenr.gov>
Subject: RE: [EXTERNAL] Initial draft Title V Permit for Duke Energy Carolinas - Buck Combined Cycle Facility

Mr. Braswell,

As we have indicated in previous correspondence, Duke Energy would like to add material to the feedstock ash at the Buck STAR® ash beneficiation facility to improve the fluidization of the ash and add a level of fire resistance to the fly ash. Use of this additive will improve operability of the facility. You requested that we review the information provided by SEFA in support of Applicability Determination No. 2501 dated June 10, 2015 where NC DAQ determined that the ash feedstock used at the STAR® ash beneficiation facility was a non-hazardous secondary material (NSHM) being used as an ingredient, and not a solid waste. The discussion below shows that addition of the proposed material does not change DAQ's previous determination.

As noted in the Determination, the STAR® process is flexible, in that operating parameters can be varied and different ingredients can be added to produce a desired product. Duke Energy is proposing to include an additive that will improve operation of the process, and according to the determination, SEFA anticipated that different ingredients could be added to the process over time. Therefore, the proposed additive does not change the process described in the Determination or the fundamental basis of the Determination.

There are four legitimacy criteria that were satisfied in order for NC DAQ to issue a determination that the ash feedstock to the STAR® process is NHSM and not solid waste.

1. Managed as a valuable commodity: Use of the proposed additive does not change how the ash feedstock is managed is a valuable commodity. It will still be stored and managed in the same manner as described in the Determination.
2. Provides a useful contribution: The ash feedstock certainly provides a useful contribution to the STAR® process and because the purpose of the proposed additive is to improve operability of the process, the proposed additive also provides a useful contribution to the process. The information in the Determination is not changed by using the proposed additive.
3. Used to produce a valuable product or intermediate: The ash feedstock used in the STAR® process is used to produce a valuable product and sold to third parties. Use of the proposed additive is for the purpose of improving the operability of the STAR® process and enhancing the facility's ability to produce a valuable product. The information in the Determination is not changed by using the proposed additive.
4. Contaminants comparable to or lower than traditional fuels: The safety data sheets (SDS) for the additives being evaluated for use were submitted to NC DAQ on May 17, 2021 and show that none of the additives contain any compounds that meet the definition of contaminant in 40 CFR 241.2. The proposed additives contain no hazardous air pollutants (HAP) or pollutants regulated by Section 129 of the Clean Air Act. Therefore, the proposed additives do not change the contaminant levels in the ash feedstock. The information in the Determination is not changed by using the proposed additive.

Therefore, we do not believe a revised Determination is required in order for NC DAQ to approve use of the proposed additive at the Buck STAR® ash beneficiation facility. Use of the proposed additive does not change the prior determination that the ash feedstock to the STAR® process is an NHSM ingredient.

Please let me know if you have any additional questions.

Thank you,

Daniel A. Markley, P.E.
Duke Energy | Lead Environmental Specialist, Permitting and Compliance, Carolinas
526 S. Church Street - EC13K | Charlotte, North Carolina 28202
Office: (704) 382-0696 | Cell: (704) 816-9164

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