Asheville-Buncombe Regional Air Quality Agency
APPLICATION REVIEW SUMMARY

SECTION A: FACILITY INFORMATION			
Company Name:	Duke Energy Progress, LLC		
Site Name:	Asheville Combined Cycle Plant		
Mailing Address:	46 Duke Energy Lane, Arden, NC 28704		
Site Address:	46 Duke Energy Lane, Arden, NC 28704		
General Description of Business:	Electric Generation		
Facility Classification:	Title V	**SITE STATUS:**	Existing

SECTION B: APPLICATION INFORMATION			
Date of Application:	November 13, 2025	**Application Tracking No.:**	NA
Date Complete Application Received:	November 14, 2025	**Board Meeting Date:**	March 26, 2026
Confidentiality Requested?	No	**Board Agenda Type:**	Modification
Application Results:	With this application, Duke Energy Progress is requesting to be reclassified as an area source of hazardous air pollutants.		
Permit No. Issued by Application:	11-628-22D / March 6, 2026		
Permit No. Voided by Application:	11-628-22C / November 20, 2025		

SECTION C: REGULATORY INFORMATION	
AB Air Quality Regulations:	4.0515, 4.0516, 4.0519, 4.0521, 4.0524, 4.0530, 4.0535, 4.0536, 4.0540, 4.0606, 4.0608, 4.0612, 4.0614, 4.1111, 4.2400, 4.2500, 17.0317, 17.0402, 17.0500, 17.0501, 17.0504

SECTION D: FACILITY-WIDE EMISSIONS INFORMATION

Pollutants Reviewed as a Result Of This Application Or AB Air Quality Action:	Actual Emissions (TONS/YR) CY 2024	Prior Potential Emissions (TONS/YR)	Potential Emissions (TONS/YR)
CO	46.4	163*	163*
NO_X	421.6*	4,208*	4,208*
PM	12.3*	108	146
PM_{10}	10.2*	98	136
$PM_{2.5}$	10.2*	98	136
SO_2	8.1*	26.0	26.0
VOC	18.8	52.8	52.8
Greenhouse Gases (GHG), $CO2_e$	1,625,070	3,525,740	3,525,740
All Hazardous Air Pollutants (HAPs)	5.3*	10.9*	10.9*
List all HAPs >10TPY of potential emissions		None	None

Potential emissions include operational limits on the combustion turbines. Potential emissions for PM, PM_{10} and $PM_{2.5}$ are based on the PAL. *Emission numbers denoted with an (*) reflect "controlled" emissions (i.e., emissions reduced by a control device).

IN COMPLIANCE WITH EMISSION STANDARDS / RECOMMEND APPROVAL			
Prepared By	James C. Raiford /	**Date Completed:**	2/10/2026
Reviewed By:	Ashley J. Featherstone /	**Date Reviewed:**	2/11/2026
Director:	Ashley J. Featherstone /	**Date Approved:**	2/11/2026

SECTION A DETAILS

FACILITY INFORMATION

[Detailed discussion of any items in Section A]

Background

Duke Energy and Progress Energy merged in 2013 to create the new Duke Energy, the nation's largest utility. The company has approximately 57,500 megawatts of electric generation capacity through a mix of fossil-fuel, nuclear and hydroelectric plants and provides electric service to approximately 7.2 million customers in North Carolina, South Carolina, and Florida in the southeast, as well as Ohio, Kentucky, and Indiana in the Midwest. Duke Energy Progress (DEP), formerly Progress Energy Carolinas (PEC), represents Duke Energy's retail service area in the Carolinas. This service area spans about 34,000 square miles and includes much of the eastern half of North Carolina, the northeastern quadrant of South Carolina, and western North Carolina, including Buncombe County.

The Asheville Steam Electric Plant is one component in DEP's system of electrical generation. In their electrical generating operations, the Asheville Steam Electric Plant operates four permitted combustion sources: two natural gas / No. 2 fuel oil-fired, combined-cycle combustion turbines (Units 5 and 7) and two natural gas / No. 2 fuel oil-fired, simple-cycle combustion turbines (Units 3 and 4). The pollutants of concern result from fuel combustion in the boilers and turbines and include carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM, including PM_{10}, $PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOCs), and various hazardous air pollutants (HAPs). In addition to the four permitted combustion sources, DEP operates various other pieces of ancillary equipment, including the following permitted equipment: a natural gas-fired auxiliary boiler, two natural gas-fired dew point heaters, two emergency generators, an emergency fire pump engine, and two cooling towers. Insignificant activities include small combustion sources, storage tanks and ash handling and storage including a coal ash landfill.

Units 5 and 7 are identical 2,207 million BTU per hour (560 megawatts) General Electric natural gas / No. 2 fuel oil-fired simple/combined cycle internal combustion (IC) turbines that began commercial operation on August 8, 2019 and September 6, 2019, respectively. (Note: The nominal heat input rate when burning No. 2 fuel oil is 1,929.8 million BTU per hour [MMBtu/hr]. These are the main units used for electrical generation at the plant. The turbines use a selective catalytic reduction system (SCR) to reduce NO_X emissions and an oxidation catalyst to reduce CO emissions. One 1,250,000 gallon No. 2 fuel oil storage tank, installed in 2019, supplies the turbines.

Units 3 and 4 are identical 1,929 million BTU per hour (165 megawatts) General Electric natural gas / No. 2 fuel oil-fired simple-cycle internal combustion (IC) turbines that began operation on May 18, 1999 and February 3, 2000, respectively. (Note: The nominal heat input rate when burning No. 2 fuel oil is 1,929.8 million BTU per hour [MMBtu/hr]. The nominal heat input rate when burning natural gas is 1654 MMBtu/hr.) The turbines are utilized as peaking units. Typically, natural gas is combusted during summer months and No. 2 fuel oil is combusted during winter months. The turbines use direct water injection to reduce NO_X emissions. Two 1,804,000 gallon No. 2 fuel oil storage tanks, installed in 1999, supply the turbines.

Area Source Reclassification

In 2021, the facility requested to be reclassified as an area source under Section 112, which means the facility's potential to emit considering controls must be less than 10 tons per year threshold for any single HAP and less than 25 tons per year for any combination of HAPs. The facility submitted testing data to establish new emission factors for formaldehyde. Additionally, the facility submitted fuel oil analysis that states that metals in the fuel oil were determined to be at de-minimis levels as compared to the previously used AP-42 values for metals. As a result of this reclassification, the facility will no longer be subject to AB Air Quality Chapter 4.1111 Maximum Achievable Control Technology 40 CFR Part 63, Subpart YYYY – "Stationary Combustion Turbines" and 40 CFR Part 63 Subpart DDDDD – "National Emission Standards for Hazardous Air Pollutants: Industrial, Commercial, and Institutional Boilers and Process Heaters". These changes were incorporated into Permit 11-682-22A dated July 12, 2022.

Permit Amendment

Duke Energy Progress, Inc. had their Title V permit renewed on January 11, 2022. During the process of renewing the permit several sections of the permit had to be moved from Section II of their previous permit and placed in Section I of the new permit. During this process, a footnote that was in the previous permit was not carried over to the new permit. Specifically, Units 5 and 7 had a footnote in permit No, 11-628-16B that stated "The SCR system is operated on an as-needed basis to meet system wide NOx limitations." This notation should have been carried over into the new permit, and has existed in our permits since the first permit was issued with these new units. The facility does not need to operate the SCR in order to achieve system wide NOx limits, and this statement is also found in other similar permits throughout the state. Duke made us aware of this error in an email on October 25, 2022. This change was incorporated into Permit 11-682-22B dated January 12, 2023.

PAL Revalidation

In a letter dated December 2, 2024, Duke Energy Progress, LLC proposed emission factors to be revalidated for their Plantwide Applicability Limits (PAL) as required by Permit Condition 2.6.A(2)(b) of Permit No. 11-628-22B. This condition states that the permittee shall revalidate the emission factors for PM and PM-10 emissions through performance testing or other scientifically valid means once every five years after the issuance of the PAL Permit (Permit No. 11-628-16B issued May 18, 2020). Asheville-Buncombe Air Quality Agency reviewed the proposed emission factors submitted for revalidation and responded on December 18, 2024 (see letter for additional information). The Agency followed the guidance for revalidation set forth by the United States Environmental Protection Agency's (EPA) memorandum issued on August 4, 2020 by Anne L. Austin.

For Units 5 and 7 when burning natural gas, the facility submitted the same emission factors that were originally part of the PAL permit and were based on vendor specifications. The Agency did not believe that the proposed factors for Units 5 and 7 met the definition of contemporaneous, and we requested that a performance test be conducted to revalidate the emission factor for combusting natural gas in Units 5 and 7.

For Units 5 and 7 when burning oil, and for the remaining auxiliary equipment (Auxiliary Boiler, Emergency Generators, Fire Pump Engine, Dew Point Heaters, Cooling Towers, Gas Heaters, Ash Handling and Haul Roads), the Agency accepted the proposed emission factors since they are not significant sources of particulate matter emissions. Units 3 and 4 were recently tested and the emission factors for those units will not change.

The facility submitted the required notification to conduct testing on January 29, 2025. On February 27, 2025, Duke Energy Progress, LLC performed the required five year revalidation testing which changed the permitted natural gas emission factors for Units 5 & 7 from 6.20 lb/hr to 10.82 lb/hr. This permit amendment changes this emission factor in the table found in condition 2.6.A(3)(a), which is used to calculate emissions for comparison with the PAL emissions limit. The facility submitted a complete application to change these emission factors on April 22, 2025, and included the required administrative amendment permit fee. These changes were incorporated into Permit 11-682-22C dated November 20, 2025.

PAL Revision

In a letter dated November 13, 2025, Duke Energy Progress, Inc. proposed revising their PAL emission limits to incorporate the recent emission factors that were updated during the PAL Revalidation. When the PAL was first established in 2020, the limit was calculated using an emission factor of 6.20 lb/hr for Units 5 and 7 when burning natural gas based on vendor-supplied emission factors. As a result of the required performance testing to revalidate the PAL emission factors, the new emission factor of 10.82 lbs/hr is now being used to calculate emissions when burning natural gas. This is resulting in higher emissions estimates, and DEP is proposing to increase the PAL limits from 108 tons per year to 146 tons per year for PM and from 98 tons to 136 tons per year for PM-10.

The agency reviewed the "Guidance on Plantwide Applicability Limitation Provisions Under the New Source Review Regulations" memorandum issued on August 4, 2020 by Anne L. Austin of the United States Environmental Protection Agency (EPA). In this document, it states:

> Sources and reviewing authorities should ensure, however, that when emission factors are adjusted or revised for PAL monitoring purposes, the baseline actual emissions calculations used to set the PAL level are adjusted as appropriate to avoid inequitable outcomes. This may be accomplished through the mandatory reopening provisions at 40 CFR 52.21(aa)(8)(ii)(a)(1), which apply to the correction of "typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL.
>
> Pursuant to 40 CFR 52.21(aa)(8)(ii)(c), if the correction(s) results in an increase in the level of the PAL, the reopening shall be carried out in accordance with the public participation requirements of 40 CFR 52.21(aa)(5).

This change will be made according to 40 CFR 52.21(aa)(8)(ii)(a)(1) to "reflect a more accurate determination of emissions used to establish the PAL". The PAL limits will be increased from 108 tons per year to 146 tons per year for PM and from 98 tons to 136 tons per year for PM-10. Since the PAL limit is increasing, there will be an allowance for public participation as required by 40 CFR 52.21(aa)(5).

SECTION B DETAILS

APPLICATION INFORMATION

[List all emission sources (permitted and exempt) reviewed as a result of this application, their associated control devices and pollutants. Provide a detailed discussion of any other items in Section B at bottom under "Application Notes."]

Emission Source ID	Emission Source Description 1. Type, manufacturer, capacity 2. Control device with ID (if any)	Pollutant(s) Emitted	Miscellaneous Notes
Permitted Sources			
Unit 5 and Unit 7	Two (2) natural gas/No. 2 fuel oil fired simple/combined cycle internal combustion turbines with a nominal rated capacity of 2,207 MMBtu/hr each, each equipped with SCR (SCR5 and SCR7) and oxidation catalyst (OxdnCat5 and OxdnCat7), equipped with two steam turbines.	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	SCR system and oxidation catalyst are applicable for combined-cycle mode of operation only. Bypass stacks are included for simple cycle mode. Two different combustion turbines were under consideration, manufacturers were GE and Siemens. Total generator output capacity for both units combined is estimated at between 400,000 and 560,000 KW or 400 to 560 MW. Please see additional notes below. As part of this modification, the heat input is being updated in the permit based on the final selection of the equipment, which was the GE units. The emissions estimates were updated in the application accordingly.
Unit 3 IC Turbine	One (1) 1,929 million BTU per hour General Electric natural gas / No. 2 fuel oil-fired simple-cycle internal combustion turbine	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	This unit employs direct water injection to reduce NO_X emissions.
Unit 4 IC Turbine	One (1) 1,929 million BTU per hour General Electric natural gas / No. 2 fuel oil-fired simple-cycle internal combustion turbine	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	This unit employs direct water injection to reduce NO_X emissions.
AuxBoiler	One (1) 47.6 MMBtu/hr natural gas-fired auxiliary boiler	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	
Emergency Generator 2 & 3	Two (2) diesel-fired emergency use black start engines with rated output capacities of 1,400 horsepower each	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	
Fire Pump Engine 2	One (1) diesel-fired emergency use fire pump engine with a rated output capacity of 335 horsepower	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	

DPH1A and DPH1B	Two (2) 8.8 MMBtu/hr natural gas-fired dew point heaters	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	
CTWR1 & CTWR2	Two (2) cooling towers	PM, PM_{10}, $PM_{2.5}$	
Emergency Generator 4	One (1) diesel-fired emergency use fire pump engine with a rated output capacity of 762 horsepower	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	This source previously listed in the insignificant activity list was added to the permitted equipment since it is subject to NSPS Subpart IIII and MACT Subpart ZZZZ.
Emergency Generator 5	One (1) diesel-fired emergency use fire pump engine with a rated output capacity of 142 horsepower	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	In a letter dated February 4, 2021, DEP notified the Agency of the addition of this engine. This source would be considered an insignificant activity but was added to the permitted equipment since it is subject to NSPS Subpart IIII and MACT Subpart ZZZZ.
Heat 1	One (1) 4.0 MMBtu/hr natural gas-fired heater	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	This source previously listed in the insignificant activity list was added to the permitted equipment list because it was included in a facility wide NC Air toxics analysis.

Insignificant Activities [per AB Air Quality 17.0503(8)]			
1	Two (2) 1,804,000-gallon capacity aboveground No. 2 fuel oil storage tank	VOCs	
4	One (1) 4.00 million BTU per hour natural gas-fired gas heater	CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	
8	Two (2) 6,200-gallon capacity lube oil tanks	VOCs	
9	Two (2) 250-gallon capacity false start drain tanks	VOCs	
17	One (1) 500-gallon capacity mobile diesel fuel storage tank	VOCs	
18	Ash handling /Ash pond / Landfill	PM, PM_{10}, $PM_{2.5}$	
23	Two (1) 400 gallon capacity 19% aqueous ammonia stainless steel totes for chemical injection system	TAP	
25	Two (2) 22,000 gallon capacity 19% aqueous ammonia storage tank sized for 168 hours full duct-fired load for SCR Injection	TAP	
26	One (1) 1,250,000-gallon capacity aboveground No. 2 fuel oil storage tank	VOCs	The facility has indicated that they may install one additional tank of this size in the future.

28	Road Dust	PM, PM_{10}, $PM_{2.5}$	Road dust was included in the insignificant activity list for the current permit modification since it is included in facility wide emissions for the PALs. It will be added to the insignificant activity list in the permit as part of this modification.
29	Four (4) 2.15 MMBtu/hr natural gas-fired turbine building heaters	CO, NOx, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	These sources meet the definition of insignificant activities in Chapter 17.0503(8).
30	One (1) 0.808 MMBtu/hr natural gas-fired auxiliary boiler building heater	CO, NOx, PM, PM_{10}, $PM_{2.5}$, SO_2, VOCs, HAPs/TAPs, CO_{2e}	This source meets the definition of insignificant activity in Chapter 17.0503(8).
32	One (1) 500 gallon double wall diesel tank for use in the fuel containment area	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8).
33	One (1) 500 gallon double wall gasoline tank for use in the fuel containment area	VOCs, HAPs/TAPs	This tank meets the definition of insignificant activity in Chapter 17.0503(8).
34	One (1) 500-gallon kerosene fuel tank	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.
35	One (1) portable 250-gallon fuel tank	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.
36	Two (2) 6,150-gallon storage tank for CT Lube Oil	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.
37	Two (2) 900-gallon No. 2 diesel fuel tanks for EMG	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.
38	One (1) 460-gallon No. 2 diesel fuel storage tank for emergency fire pump	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.
39	Two (2) 12,500-gallon storage tanks for ST Lube Oil	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.
40	Two (2) 230-gallon storage tanks for Electric Hydraulic Control Oil	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.

41	One (1) 460-gallon No. 2 diesel fuel storage tank for emergency fire pump	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.
42	Two (2) 2000-gallon diesel drain tank for false start	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.
43	Two (2) 300-gallon drain tanks for fuel gas condensate	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.
45	One (1) 500-gallon kerosene fuel tank for use in the fuel oil containment area	VOCs	This tank meets the definition of insignificant activity in Chapter 17.0503(8). This has been added to the insignificant activities list for this renewal.

APPLICATION NOTES

SECTION C DETAILS

REGULATORY INFORMATION

(Identify the AB Air Quality Regulations reviewed because of this application. At a minimum, the regulations already listed should be reviewed and reason given for applicability or non-applicability. If a regulation has a standard, list the standard and indicate how the source is in compliance.)

AB Air Quality Regulation Number / Title	Emission Source ID No(s). Subject	Notes On Regulation (Compliance demonstration, applicability, etc.)
17.0500 – Title V Procedures (40 CFR Part 70)	All	DEP is subject to Title V permitting procedures due to: 1) potential emissions in excess of the 100-ton per year applicability threshold for criteria air pollutants; 2) applicability of Title IV; and 3) being a source category designated by EPA as subject to the requirements of 40 CFR Part 70. With this modification, the facility will be reclassified as an area source for HAPs.
17.0700 – Toxic Air Pollutant Procedures	Heat 1	The modification for the Western Carolinas Modernization Project (11-628-16A) included new sources of TAP emissions and a review under NC Air Toxics was triggered. Several sources have since been removed. Sources subject to MACT/GACT are not listed here but were included in the toxics demonstration. For more details, please see the section under Regulatory Notes below.
4.0524 – New Source Performance Standards (40 CFR Part 60 Subpart GG)	Unit 3 IC Turbine, Unit 4 IC Turbine	Each turbine is subject to the requirements of 40 CFR Part 60, Subpart GG – "Standards of Performance for Stationary Gas Turbines." Both meet the definition of "*stationary gas turbine*" in 60.331, exceed the applicability threshold of 10.7 gigajoules per hour (10.1 million BTU per hour) in 60.330, and were constructed after the applicability date of October 3, 1977 in 60.330. As such, both are subject to a NO_X emission limitation for natural gas and fuel oil and a fuel sulfur content standard of 0.8 percent by weight. The permit was previously modified such that fuel bound nitrogen is no longer of concern.

4.0524 – New Source Performance Standards (40 CFR Part 60 Subpart KKKK)	Unit 5 and Unit 7	These turbines are subject to the requirements of 40 CFR Part 60, Subpart KKKK – "Standards of Performance for Stationary Combustion Turbines." This rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hour that commenced construction after February 18, 2005. Subpart KKKK includes emissions limits for SO_2 and NOx. The turbines will fire pipeline quality natural gas or ultra-low sulfur fuel oil (15 ppm sulfur) to comply with the SO_2 limit of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. The NOx limit for turbines that are greater than 850 MMBtu/hour is 15 ppm at 15% O_2 when the unit is operating at greater than 75% ISO load on at least 50% natural gas, 42 ppm at 15% O_2 when the unit is operating at greater than 75% ISO load on at least 50% oil, and 96 ppm at 15% O_2 when operating at a load less than 75% or at temperatures less than 0 degrees F. A NOx CEMS will be used to monitor compliance with the limit. Excess emissions is defined as any unit operating period in which the 30 day rolling average (combined cycle units) NOx emission rate exceeds the applicable emission limit. Affected sources must operate and maintain their stationary combustion turbine and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction.
4.0524 – New Source Performance Standards (40 CFR Part 60 Subpart TTTT)	Unit 5 and Unit 7	These turbines are subject to the requirements of 40 CFR Part 60, Subpart TTTT – "Standards of Performance for Greenhouse Gas Emissions from Electric Generating Units." These standards were promulgated on October 23, 2015. This rule establishes standards for emissions of carbon dioxide (CO_2) for affected fossil fuel fired electric generating units (EGUs) constructed after January 8, 2014. The standard for newly constructed base load stationary combustion turbines that combust more than 90% natural gas on an annual heat input basis is 1,000 lb CO_2/MWh gross energy output.
4.0524 – New Source Performance Standards (40 CFR Part 60 Subpart IIII)	Emergency Generators 2,3,4,5, and Fire Pump Engine 2	These emergency-use generators are subject to the requirements of 40 CFR Part 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, which requires the manufacturer to certify that the generators meet the emission limits listed in the subpart. The generators must be equipped with a non-resettable hour meter and nonemergency use (e.g., testing) is limited to 100 hours per year. Ultra low sulfur diesel (ULSD) fuel (15 ppm) must be used. The owner or operator is required to maintain records of emissions certifications, hours of operation and reason for operation, and maintenance activities.

4.0524 – New Source Performance Standards (40 CFR Part 60 Subpart Dc)	AuxBoiler	The auxiliary boiler is subject to 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Subpart Dc applies to steam generating units with a heat input capacity greater than 10 MMBtu/hour but less than 10 MMBtu/hour for which construction commenced after June 9, 1989. The auxiliary boiler fires natural gas only and as a result, it is not subject to PM or SO_2 requirements of this rule. The source is subject to the requirement to maintain records of the amount of fuel combusted during each day or each calendar month per 40 CFR 60.46c(g).

4.0530 – Prevention of Significant Deterioration and 17.0317 – Avoidance Conditions	Unit 3 IC Turbine, Unit 4 IC Turbine, Unit 5, Unit 7, AuxBoiler Emergency Generators 2, 3, 4, 5, Fire Pump Engine 2, DPH1A and DPH1B, CTWR1 & CTWR2	The PSD regulations apply to major modifications at major stationary sources, which are considered those sources belonging to any one of the 28 source categories listed in the regulations that has the potential to emit more than 100 tons per year of any PSD regulated compound, or any other source which has the potential to emit more than 250 tons per year of any PSD compound. DEP is one of the 28 source categories (fossil-fueled steam electric plants greater than 250 MMBtu/hour heat input) and is a major stationary source for the purposes of PSD applicability. Since the time when the final PSD regulation was published in 1980, DEP has made no major modifications that are subject to a PSD review. At the time Unit 3 IC Turbine and Unit 4 IC Turbine were constructed, DEP requested avoidance conditions be placed in their permit to govern the modification such that a significant net emissions increase did not occur for any regulated pollutant. Avoidance conditions for Units 3 and 4 include a fuel oil sulfur content limit of 0.05 percent by weight and limiting total emissions from both units to 40 tons of SO_2 per year, 25 tons of PM per year, and 15 tons of PM_{10} per year; and limit facility-wide NO_X emissions to 13,725 tons per year. Compliance with these limitations is determined through monitoring, recordkeeping, and reporting over a consecutive 12-month rolling period. As part of the modification for the Western Carolinas Modernization Project (covered under Permit No. 11-628-16A), the proposed project's emissions were evaluated to determine whether PSD permitting is required. The net project emissions increases show that all emissions increases can be limited to rates below the PSD significant emissions rates. DEP requested PSD avoidance limits for CO, NOx, and filterable PM. All of the turbine exhaust stacks will be equipped with CEMS for NOx, CO, and O_2. The permit (11-628-16A) when issued included PSD avoidance limits for all NSR pollutants evaluated as part of this modification, with the exception of fluorides (NOx, SO_2, PM (filterable), PM_{10}, $PM_{2.5}$, CO, VOCs, sulfuric acid, and lead). Monitoring and reporting requirements are included in the permit for all pollutants listed here with the exception of sulfuric acid and lead, since potential emissions are less than the annual emissions limits that were utilized to ensure that the project emissions increases are below the PSD significant emission rates. In 2019, DEP has applied for a significant modification to establish plantwide applicability limits (PALs) and the issuance of a PAL permit in accordance with 40 CFR 51.166(w). A PAL is a pollutant-specific, source-wide emission limitation, expressed in tons per year ("TPY"), which provides a voluntary alternative for complying with the PSD

		preconstruction permitting program requirements. With a PAL, the owner or operator of a stationary source can make changes to the source without triggering PSD preconstruction permitting requirements as long as facility-wide emissions do not increase above the limit established by the PAL for a particular pollutant. When a PAL is established in a permit, all other PSD avoidance limits are removed from the permit for that pollutant. The PALs for 2 pollutants (PM, and PM-10) are based on the potential emissions from the new units installed plus the PSD significance level for each pollutant. As part of this permit modification, DEP is requesting to increase the PAL limits from 108 tons per year to 146 tons per year for PM and from 98 tons to 136 tons per year for PM-10. The reason that the PAL limits are increasing is because the emission factors for Units 5 and 7 increased after the facility conducted performance testing to revalidate their emission factors used to establish the PAL. Additional information can be found in Section A of this review.

4.1110 – National Emission Standards for Hazardous Air Pollutants (40 CFR Part 61)	NA	The facility has no equipment or processes subject to a standard under 40 CFR Part 61.
4.1111 – Maximum Achievable Control Technology (40 CFR Part 63 Subpart ZZZZ)	Emergency Generators 2,3,4,5, and Fire Pump Engine 2	The emergency engines are subject to 40 CFR Part 63, Subpart ZZZZ – "Reciprocating Internal Combustion Engines (RICE). Compliance with Subpart ZZZZ for new units is achieved by compliance with NSPS Subpart IIII (purchase of a certified engine).
4.1111 – Maximum Achievable Control Technology (40 CFR Part 63 Subpart YYYY)	Unit 5, Unit 7, Unit 3 IC Turbine, Unit 4 IC Turbine	Unit 5 and Unit 7 were previously subject to 40 CFR Part 63, Subpart YYYY – "Stationary Combustion Turbines", which applied to major sources of HAP emissions. Because of the reclassification of the facility as an area source of HAPs, this Subpart no longer applies and has been removed from the permit.
4.1111 – Maximum Achievable Control Technology (40 CFR Part 63 Subpart JJJJJJ)	AuxBoiler, DPH1A and DPH1B	The auxiliary boiler and the two new gas-fired dew point heaters were previously subject to 40 CFR Part 63 Subpart DDDDD – "National Emission Standards for Hazardous Air Pollutants: Industrial, Commercial, and Institutional Boilers and Process Heaters" which applied to major sources of HAP emissions. Because of the reclassification of the facility as an area source of HAPs, Subpart DDDDD no longer applies and has been removed from the permit. These sources are also not subject to 40 CFR Part 63 Subpart JJJJJJ – "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources" as specified in 40 CFR 63.11195(e) because they burn natural gas. A condition was added to the permit to define gas-fired sources and to list notification and reporting requirements if they were to switch to burning fuel oil.

4.0503 – Particulates from Fuel Burning Indirect Heat Exchangers	AuxBoiler, DPH1A and DPH1B	The allowable emissions of particulate matter shall be determined by the following equation, where Q is the maximum heat input in million Btu/hour (MMBtu/hr) and E is the allowable emission rate for particulate matter in pounds per million Btu (lb/MMBtu): $E = 1.090 * (Q)^{-0.2594}$ For the purpose of this Rule, the maximum heat input shall be the total heat content of all fuels which are burned in a fuel burning indirect heat exchanger, of which the combustion products are emitted through a stack or stacks. The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site which are in operation, under construction, or permitted pursuant to Chapter 17, shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter for each fuel burning indirect heat exchanger. The maximum heat input for the auxiliary boiler is 47.6 MMBtu/hour. Maximum heat input for the two dew point heaters is 8.8 MMBtu/hour each. As such, the total heat input for all subject boilers is 65.2 MMBtu/hour and the calculated PM limit is 0.37 lb/MMBtu. The sources are expected to be in compliance since they will only fire natural gas. No additional monitoring, recordkeeping, or reporting will be required.
4.0515 – Particulates from Miscellaneous Industrial Processes	CTWR1 & CTWR2	The allowable emission rate is a function of the process weight rate and shall be determined by the following equation, where P is the process throughput rate in tons per hour (tons/hr) and E is the allowable emission rate in pounds per hour (lbs/hr): $E = 4.10 * (P)^{0.67}$ for $P \leq 30$ tons/hr $E = 55.0 * (P)^{0.11} - 40$ for $P > 30$ tons/hr Provided the facility maintains the dust collector on the sorbent trailers, it will be assumed these operations are in compliance with this regulation. For the cooling towers, the process rate is estimated to be 35,028 tons per hour (based on water circulation rate of 140,000 gallons per minute, density of 8.34 pounds per gallon at 59 degrees F). The allowable PM emission rate is 134 lb/hr. DEP has estimated that the maximum PM emission rate for the cooling towers is 0.35 pounds per hour, which is based on an expected TDS concentration of 1,000 ppm and a total drift rate of 0.0005%. As such, compliance with the emissions limit is expected and no monitoring, recordkeeping, or reporting will be required.

4.0516 – Sulfur Dioxide Emissions from Combustion Sources	AuxBoiler, DPH1A and DPH1B	These units are subject to this regulation because they combust sulfur-containing fuels. This regulation limits SO_2 emissions from each unit to 2.3 pounds per million BTU heat input. Since these units burn natural gas, they are expected to comply with this limit.
4.0521 – Control of Visible Emissions	Unit 3 IC Turbine, Unit 4 IC Turbine, Unit 5, Unit 7, AuxBoiler Emergency Generators 2, 3, 4, 5, Fire Pump Engine 2, DPH1A and DPH1B, CTWR1 & CTWR2,	These units are subject to this regulation because they are combustion sources. Visible emissions from all sources are limited to 20% opacity.
4.0540 – Particulates from Fugitive Non-process Dust Emission Sources	Facility-Wide	The intent of placing this regulation in the facility's permit is to govern facility-wide fugitive emissions from non-process sources, including fugitive emissions associated with handling, transportation and storage of coal ash. The facility will take reasonable precautions to prevent particulate matter from becoming airborne as the result of storage, transportation, processing, and/or handling of materials. Compliance with this regulation will be determined through facility self-monitoring and Agency inspections.
4.2400 – Clean Air Interstate Rule (CAIR) and the Cross State Air Pollution Rule (CSAPR)	Unit 3 IC Turbine, Unit 4 IC Turbine, Unit 5 and Unit 7	These units were subject to CAIR because they are specified in the list of electric utility boiler units in the regulation. The Cross-State Air Pollution Rule became effective in January of 2015. Currently this rule is a Federal Implementation Plan (FIP); however, it has not yet been incorporated into the North Carolina State Implementation Plan (SIP). On February 1, 2016, the CAIR provisions in the state SIP (15A NCAC 02D .2400) expired. For this permit renewal application, the Clean Air Interstate Rule, CAIR, had been replaced by the Cross-State Air Pollution Rule (CSAPR). The permit was previously modified to include the references to the applicable requirements of CSAPR.
17.0402 – Acid Rain Permitting Procedures (40 CFR Parts 72 & 76)	Unit 3 IC Turbine, Unit 4 IC Turbine, Unit 5 and Unit 7	A revised acid rain permit application was submitted by DEP in October of 2020 to reflect the removal of Units 1 and 2 from the facility. This updated plan and application was incorporated into Section 4 of the permit.

REGULATORY NOTES

SECTION D DETAILS				
Emission Information				
Calculation Method Codes (List all that apply)	1 = Stack test result 2 = Material (mass) balance 3 = EPA approved information (AP-42, CTG, etc.) 4 = Other (specify in table below)			
Calculation Rejection Codes (List all that apply)	1 = Calculation error 2 = Wrong emission factor(s) used 3 = Control efficiency(ies) not accepted 4 = Other (specify in table below)			
Emission Source (ID No.)	**Calculation Method Code**	**Accept or Reject?**	**Calculation Rejection Code**	**AB Air Quality Calculations Attached?**
Facility-Wide	1, 2, 3	Accept	NA	No

EMISSION NOTES

DEP calculations for the 2024 actual emissions were used for the review.

SECTION E

Supporting Documentation
(Provide brief description of any attachments)

1. Permit Application dated November 13, 2025
2. Notifications to EPA, and surrounding state and local air agencies
3. Public notice
4. Draft permit
5. Draft permit cover letter