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a PPL company

December 15, 2022

Mr. Matt King
Industrial Permitting Manager
Air Pollution Control District
701 West Ormsby Ave, Suite 303
Louisville, KY 40203

RE: NGCC Unit 5 Air Permit Application
Louisville Gas & Electric Company – Mill Creek Generating Station; Plant ID: 127

Dear Mr. King:

Louisville Gas & Electric Company (LG&E) currently operates an electric generation power plant, the Mill Creek Generating Station (Mill Creek), located in Jefferson County, Kentucky. The facility is classified as a major source under the Title V Operating Permit Program and currently operates in accordance with Title V Air Operation Permit No. O-0127-20-V.

LG&E is submitting the enclosed air permit application to obtain a construction permit and amended Title V Operating Permit to include the installation of a new 664 MW (net) natural gas-fired combined cycle (NGCC) electric generating Unit 5. In light of their book life and upcoming new regulatory requirements that would be imposed, the existing Units 1 and 2 coal boilers are also being retired and NGCC Unit 5 is being constructed to replace their capacity.

The NGCC Unit 5 will consist of one natural gas-fired gas combustion turbine, a steam turbine, and one heat recovery steam generator (HRSG) with natural gas-fired duct burners arranged in a one-on-one configuration. NGCC Unit 5 will utilize dry-low-NO_X combustors in the gas turbine and low-NO_X duct burners in the HRSG. It will also be equipped with an oxidation catalyst and Selective Catalytic Reduction as add-on control systems to reduce stack NO_X, CO, hydrocarbons, and organic hazardous air pollutant emissions. The use of a highly efficient combined cycle 1 x 1 gas turbine and HRSG unit will also minimize greenhouse gas emissions by extracting the maximum amount of usable energy from the fuel gas, thus minimizing the amount of natural gas required to be combusted to generate electricity.

The state-of-the-art technology design features as well as the control measures being used for NGCC Unit 5, combined with the emission reductions from the shutdown of the Units 1 and 2 coal boilers, will result in a significant improvement in the air emissions profile for the Mill Creek Generating Station. Following the implementation of the NGCC Project, there will be significant reductions in actual emission for NO_X, SO_2, and particulate matter. The significant decreases in NO_X emissions should contribute to reductions in regional ozone concentrations. In addition, the project is expected to result in net CO_2e emission reductions. Coupled with these significant environmental benefits, the planned project will bring a major new capital investment to the Mill

Creek Generating Station and help ensure that it remains a critical asset for the company to meet the energy needs of its customers for several decades.

In recognition of U.S. EPA's current environmental justice policies, LG&E has performed certain environmental justice reviews. LG&E evaluated the Mill Creek Generating Station and the surrounding area using Version 1.0 of the *Climate & Economic Justice Screening Tool*. Mill Creek resides in tract number 21111012104 in Jefferson County. This tract is considered disadvantaged because it meets more than 1 burden threshold and the associated socioeconomic threshold. The area met the threshold for Health (Life Expectancy and Low Income) and Housing (Lack of Indoor Plumbing and Low Income). This project has no significant impacts to the environment and will also result in environmental benefits by facilitating replacement of higher emitting coal-fired generating units at the site. The localized air emissions and traffic reductions resulting from the project should theoretically translate to improved health (life expectancy) outcomes. The combination of indicators for the Housing threshold are not related to LG&E operations. This project will provide economic benefit in the local to the community and reliable, affordable electric service to the LG&E customers generally.

Although currently there are no specific legal requirements mandating environmental justice review as part of the state review process, LG&E opted to perform the above-referenced environmental justice review in order to be both proactive and transparent.

We look forward to working in cooperation with Air Pollution Control District (APCD) personnel to help ensure the timely and successful completion of this permit action. To support the project procurement timeline, LG&E is requesting to obtain the construction permit authorizing the project by **October 1, 2023**.

In follow-up to submittal of the enclosed hard-copy of the application, LG&E will separately email a searchable PDF electronic file of the entire application by email along with the dispersion modeling analysis files used in completing the Strategic Toxic Air Reduction (STAR) Program compliance demonstration analysis. In addition, LG&E will also be providing a copy of the Excel file that contains the emissions calculations presented in the application.

If you or any other APCD staff have any questions or need additional information as you initiate your review of the application, please do not hesitate to contact me at (502) 627-2791 or brandan.burfict@lge-ku.com.

Sincerely,

DocuSigned by:
Brandan Burfict
275A1971A06448A...

Brandan Burfict
Manager, Environmental Air

Enclosure

cc: Mr. Philip Imber, Director, Environmental and Federal Regulatory Compliance, LG&E
Ms. Marlene Zeckner Pardee, Senior Environmental Scientist, LG&E

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Mr. Paul J. Smith, P.E., Director, Trinity Consultants
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AIR PERMIT APPLICATION
New NGCC Combustion Turbine Project

a PPL company

Louisville Gas & Electric Company
Mill Creek Generating Station
14460 Dixie Hwy
Louisville, KY 40272

December 15, 2022

Prepared By:

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1. APPLICATION SUMMARY

Louisville Gas & Electric Company (LG&E) currently operates an electric generation power plant, the Mill Creek Generating Station (Mill Creek), located in Jefferson County, Kentucky. The facility is classified as a major source under the Title V Operating Permit Program and currently operates in accordance with Title V Air Operation Permit No. O-0127-20-V, with an effective date of July 27, 2020, issued by the Louisville Metro Air Pollution Control District (APCD). This permit authorizes operation of coal boilers (Units 1 through 4); coal, limestone, fly ash, PAC, and gypsum handling and storage operations; emergency equipment; miscellaneous organic liquids tanks; parts washers; cooling towers; general plant fugitive emissions; and numerous insignificant activities.

1.1 Purpose of Application

LG&E is submitting this air permit application to obtain a construction permit and amended Title V Operating Permit to cover the planned installation of a new 664 MW (net) natural gas-fired combined cycle (NGCC) electric generating unit (Unit 5). In light of their book life and upcoming new regulatory requirements that would be imposed, the existing Units 1 and 2 coal boilers are also being retired and the NGCC Unit is being constructed to replace their capacity. The existing Units 3 and 4 coal boilers and the shared associated coal and other material storage and handling operations (except for a small reduction in the footprint of the existing coal storage pile) will be retained and are not being modified by the planned project. LG&E will utilize and optimize the current electrical transmission system in conjunction with completing the NGCC Project.

The new NGCC Unit proposed will consist of one natural gas-fired gas combustion turbine (GT), one steam turbine (ST), and one heat recovery steam generator (HRSG) with natural gas-fired duct burners (DB) arranged in a one-on-one configuration. Ancillary support equipment will also be installed to support the NGCC Unit operations, including one natural gas-fired boiler (Auxiliary Boiler) rated at 99.9 million British thermal units per hour (MMBtu/hr) or less, one pipeline fuel gas (dewpoint) heater rated at 15 MMBtu/hr or less, one 2 megawatts (MW) emergency generator with diesel-fired engine, one 400 horsepower (HP) emergency diesel driven fire pump engine, and one 8-cell mechanical draft cooling tower.

Jefferson County is currently designated as an attainment or unclassified area with respect to the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants except ozone, for which it is classified as a nonattainment area with respect to the 2015 ozone (O_3) standard. The facility is currently classified as an existing major source under both the Prevention of Significant Deterioration (PSD) and nonattainment New Source Review (NSR) permitting programs. Since the new NGCC Unit will be constructed and operated within the existing Mill Creek Generating Station property, it will have the same standard industrial classification (SIC) code as existing operations, and will be under the same common control and/or ownership; hence, the NGCC Project will be considered a modification to an existing major stationary source. Therefore, the applicability of the proposed NGCC Project to the NSR permitting regulations is evaluated.

As documented within this application, the total NGCC Project emission increases, consisting of the sum of the differences of potential emissions from new emission units and the differences between projected actual and baseline actual emissions for existing emission units, is below the NSR major modification thresholds for all relevant regulated NSR pollutants.[1] Therefore, the project is not subject to PSD or nonattainment NSR permitting requirements. The emission increases are also below 50% of the PSD Significant Emission Rates for all pollutants; therefore, the reasonable possibility recordkeeping requirements under the PSD regulations are also not triggered and is there no need to establish any new synthetic limits on operations or emissions.

Emission units associated with the new NGCC Project will be subject to New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and several APCD air regulations. The facility is currently classified as a major source of hazardous air pollutants (HAPs) and will retain this classification following the completion of the NGCC Project.

1.2 Project Schedule

LG&E is targeting for commercial operation of the new NGCC Unit to begin no later than April 1, 2027. Given that the construction and commissioning of the NGCC Unit is expected to last 37 months, the anticipated start of construction will be March 1, 2024. Additional time will be needed for LG&E to finalize contracts with major equipment suppliers for the project ahead of this construction target date and this generally cannot occur until the air construction permit is obtained due to the financial commitments involved. Therefore, to satisfy LG&E's mandate and obligations to provide safe, reliable electrical power to the market, it is important that construction authority for this project be obtained in a timely manner. LG&E will be seeking opportunities to proactively engage with APCD staff and is committed to providing information and/or timely responses to any questions to allow the agency's review and processing of this application and development of a construction permit to proceed as smoothly as possible. LG&E requests to obtain the construction permit by **October 1, 2023**.

1.3 Summary of Application Contents

This application package, consisting of this report, and four appendices is organized as follows:

- Section 2 provides relevant background information about the Mill Creek Generating Station and information about the proposed new NGCC Unit 5 operations and existing operations that are being shut down.
- Section 3 discusses the emissions calculation methodologies used to define the potential emissions from the new emission units/ancillary equipment, associated with the NGCC Project, and provides a summary of the total emissions by pollutant.
- Section 4 presents the methodology used to calculate project emission increases and the NSR applicability analysis.
- Section 5 provides a summary review of applicable regulatory requirements under state and federal air quality programs impacted by the NGCC Project.
- Appendix A contains both area and aerial maps that show the location of Mill Creek Generating Station relative to nearby geographic features, site arrangement drawings for the new NGCC Unit within the existing facility, and a process flow diagram for the new emission units.

[1] Relevant regulated NSR pollutants for the NGCC Project are particulate matter (PM), PM 10 microns or less in diameter (PM_{10}), PM 2.5 microns or less in diameter ($PM_{2.5}$), oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), sulfur dioxide (SO_2), sulfuric acid (H_2SO_4) mists, lead (Pb), and greenhouse gases (GHG).

- Appendix B provides an inventory of the existing and new proposed emission units at the Mill Creek Generating Station; a derivation of potential emissions from the new emission units associated with the NGCC Project; and the baseline actual emissions for existing emission units that are being shut down.
- Appendix C provides all the APCD application forms required for processing of this application along with a copy of the acid rain program revision application for the project.
- Appendix D provides sample suggested edits to the existing Mill Creek Generating Station Title V permit encompassing the regulatory and permitting requirements impacted by the NGCC Project.

2. PROJECT DESCRIPTION

This section describes the proposed NGCC Project and the new emission units that will be installed and operated at the existing Mill Creek Generating Station.

2.1 Site Location

Mill Creek Generating Station sits on approximately 637 acres in southwest Jefferson County, KY, along the Ohio River approximately 16 miles south-southwest of downtown Louisville.

Figure A-1 in Appendix A shows the facility location and the surrounding area on a topographical map. The Universal Transverse Mercator (UTM) coordinates of the Mill Creek Generating Station's center are (approximately) 595.661 kilometers (km) East and 4,212.109 km North (Zone 16, NAD83). Figure A-2 shows an aerial image of the plant denoting the location of existing plant operations and emission units.

2.2 Background on Existing Site Operations and Emission Units

Mill Creek Generating Station, which began operation in 1972, is LG&E's largest coal-fired power plant, with a nameplate generating capacity of 1,717.2 megawatts (MW). The primary emission units at the plant are four (4) base load coal-fired utility boilers (Units 1-4).

- Unit 1 (E1) is a Combustion Engineering tangentially fired boiler constructed in 1970 with a rated capacity of 3,085 MMBtu/hr, 355.5 MW, using pulverized coal as a primary fuel and natural gas as secondary fuel. Air pollution controls consist of low NO_X burners (LNBs), electrostatic precipitators (ESP), powdered activated carbon (PAC) injection system, dry sorbent injection (DSI) system (and/or liquid additive system), pulse-jet fabric filter (PJFF) baghouse, and wet flue gas desulfurization (WFGD) unit.
- Unit 2 (E3) is a Combustion Engineering tangentially fired boiler constructed in 1970 with a rated capacity 3,085 MMBtu/hr, 355.5 MW, using pulverized coal as a primary fuel and natural gas as secondary fuel. Air pollution controls consist of LNBs, ESP, PAC injection system, DSI system (and/or liquid additive system), PJFF baghouse, and WFGD unit.
- Unit 3 (E5) is a Babcock & Wilcox dry bottom, wall-fired boiler constructed in 1973 with a rated capacity of 4,204 MMBtu/hr, 462.6 MW, using pulverized coal as a primary fuel and natural gas as secondary fuel. Air pollution controls consist of LNBs, ESP, Selective Catalytic Reduction (SCR), PAC injection system, DSI system (and/or liquid additive system), PJFF baghouse, and WFGD unit.
- Unit 4 (E7) is a Babcock & Wilcox dry bottom, wall-fired boiler constructed in 1975 with a rated capacity 5,025 MMBtu/hr, 543.6 MW, using pulverized coal as a primary fuel and natural gas as secondary fuel. Air pollution controls consist of LNBs, ESP, SCR, PAC injection system, DSI system (and/or liquid additive system), PJFF baghouse, and WFGD unit.

2.3 Proposed New Operations

Mill Creek Generating Station's coal-fired Units 1 and 2 are reaching the end of their economic lives and over the last few years, LG&E has started the process of evaluating all available generation options to meet the energy needs of its customers. Based on this evaluation, LG&E plans to construct and operate a new 664 MW (net) natural gas-fired NGCC Unit at the existing Mill Creek Generating Station. The retirement of Units 1 and 2, will reduce the site's gross generation by 711 MW. LG&E has chosen to add a NGCC Unit as a new asset because of its ability to operate as a base loaded unit and because it can be quickly and efficiently dispatched. New technology allows rapid startups. The NGCC Unit will replace the capacity lost with the retirement of Units 1 and 2.

As part of the NGCC Project, the following new air emissions units will be installed:

- NG-fired combined cycle power plant with one combustion turbine (GT) and its single-shaft water cooled generator (7HA.03, 501JAC, 9000HL, or similar), one HRSG equipped with NG-fired duct DBs, and one ST arranged in a one-on-one configuration.
- Auxiliary Boiler using NG and a rated higher heating value (HHV) heat input capacity of 99.9 MMBtu/hr
- Fuel Gas (Dewpoint) Heater using NG with a heat input capacity of 15 MMBtu/hr
- 2000 kW (2,682 nominal brake horsepower [bhp]) emergency generator with diesel-fired engine (U.S. EPA Certified Tier 2) and associated diesel storage tank
- 400 bhp emergency diesel driven fire pump engine (U.S. EPA Certified Tier 3) and associated diesel storage tank
- Mechanical draft cooling tower (8 Cell)
- Lube oil system demister vents
- Ancillary equipment, including raw and demineralized water storage tanks; aqueous ammonia storage and handling equipment; and miscellaneous HVAC heaters

A process flow diagram showing the proposed NGCC Unit operations is provided in Figure A-6 in Appendix A, and each of the proposed new air emission units is discussed in the following subsections. Figure A-3 shows an overlay of the planned location of the new NGCC Unit operations on an existing aerial image of the Mill Creek Generating Station. The same equipment layout location is shown on a facility site diagram in Figure A-4. Finally, Figure A-5 provides a detailed arrangement of the proposed new NGCC Project emission units and associated structures.

LG&E is currently in the process of evaluating and selecting the primary vendor that will provide the core NGCC Unit equipment and a final selection will not be made until farther in the project development process. There are currently three primary vendors being evaluated that are correspondingly referred to in this application as Vendor A, Vendor B, or Vendor C. LG&E has provided a set of minimum equipment specifications and emissions performance guarantees that must be met by each vendor. Because the operating scenarios and potential emissions represented in this permit application encompass the worst-case combination of the data and parameters provided by each vendor for their equipment packages, the regulatory and permit applicability review can be completed without yet knowing which specific vendor will ultimately be selected for the project.

2.3.1 NGCC Unit 5 (U23/E49a-E49e)

As illustrated in Figure A-6 in Appendix A, in a combined-cycle process, ambient air is drawn into the compressor section of the GT through an inlet air filtration system. Inlet evaporative cooling may take place during periods of warm ambient temperatures and low relative humidity to further enhance the overall production capability of the GT. After the evaporative cooler (EC) section, air enters the compressor section where it is compressed and channeled to the fuel/mix combustion section of the GT.

The compressor section of the GT, commonly referred to as the gas generator section, generates emissions from the fuel combustion process. A transition duct within the GT directs the flow of hot gases from the gas generator to the power section of the turbine. Gas generator combustion gases expand through the stages of the power turbine where the thermodynamic energy is converted to mechanical power. This mechanical power is then transmitted through the rotation of the shaft to the generator of the GT, which is directly coupled to the power turbine. The generator takes this rotational power and converts it to electricity.

The hot combustion gases that are produced in the GT are directed into the HRSG through an exhaust transition duct where waste heat is captured and converted into steam energy before the exhaust gases exit the vertical stack. The HRSG duct contains the natural gas-fired DBs, which will be used at times to increase the temperature of the exhaust in the HRSG to enable the production of additional steam on an as-needed basis. This installation will primarily use DBs in the summer months and thus provide supplemental heat input capacity with the goal of ensuring the same MW generation as the winter months.

The steam produced in the HRSG is used in the ST to produce additional electrical power. Once mechanical work from the steam is captured, the steam is exhausted, and condensed in a vacuum within a condenser. The condensate is reused as feed water to the HRSG, creating a closed-loop system.

The GT in conjunction with the DBs is the primary emissions unit for the NGCC Project. The proposed NGCC Unit is designed for continuous operations. The GT will be capable of operating between a nominal minimum emissions compliance load (MECL) and 100-percent load. MECL is defined as the minimum steady-state load at which the combustion turbine can operate at any given ambient condition and maintain compliance with all emission limits.

These base load NGCC systems are almost entirely capable of converting the latent heat from the GT exhaust to steam in the HRSG without additional DB-firing. In their draft project equipment quotes, each vendor only presented a few situations that require operation of the DBs.

With older NGCC power block systems or with simple cycle peaking units, the inclusion of the DBs was necessary to be evaluated/permitted because of their significant contribution of emissions at the combined stack (e.g., CO and NO_X). In contrast, for the proposed installation, each vendor is required to meet a 2 parts per million by volume dry (ppmvd) at 15% O_2 emissions guarantee for CO and NO_X with or without DBs; therefore, it is unnecessary to permit the various operation modes of the DBs separately. These guarantees are further supported by each vendor's commitment to install and operate add-on control devices for CO and NO_X.

The key GT/DB equipment specifications from the equipment quotes provided by the three vendor quotes are as follows:[2]

- Maximum short-term heat input capacity up to 4,216 MMBtu/hr HHV total from both GT & DB @ -18°F.
- Maximum of 4,216 MMBtu/hr HHV from GT by itself
- Maximum of 296 MMBtu/hr HHV from DBs
- 4,157 MMBtu/hr maximum simulated heat input capacity taking into account seasonal variation for this baseload operation
- 640-664 MW (net) power output from combined cycle 1 x 1 configuration at 60 Hz
- Greater than 63% combine cycle efficiency (lower heating value [LHV])
- Air cooling for combustors instead of steam cooling
- 42-75 MW/min GT ramp up
- Startup time to full load less than 30 min for a hot start
- Provides super-heated steam greater than 600°C
- Designed for future hydrogen co-firing

[2] Please note that the heat inputs and energy generation values are subject to change depending on the final equipment selection.

The operational scenarios used to establish the maximum short-term and annual emissions are discussed in Section 3 of the application.

2.3.1.1 Air Pollution Controls

All vendors will utilize dry-low-NO_X combustors (DLN) in the GT and LNBs in the HRSG. All vendors will utilize oxidation catalysts and SCR as add-on controls to reduce stack NO_X, CO, hydrocarbons (HC), and organic HAP emissions. GHG emissions will be minimized through the use of the highly efficient combined cycle 1 x 1 GT and HRSG unit. A bank of drift eliminators will be installed after the evaporative cooling media to ensure that no water droplets or solids particles from water enter the GT. Therefore, there will be no contribution of PM emissions from the evaporative cooling systems to the generating units.

Dry Low NO_X Combustors. The GT will feature each vendor's latest DLN combustion technology, which can reduce NO_X emissions to approximately 25 ppm, whereas the additional SCR system (described below) is designed to reduce NO_X emissions to less than 2 ppmvd at 15% O_2. The combustor also features low CO emissions at partial load, remaining compliant with permitted levels even at turndown to the MECL.

DLN combustor technology premixes air and a lean fuel mixture prior to injection into the combustion turbine that significantly reduces peak flame temperature and thermal NO_X formation. Conventional combustors are diffusion controlled where fuel and air are injected separately. Combustion occurs locally at stoichiometric interfaces resulting in hot spots that produce high levels of NO_X. In contrast, DLN combustors generally operate in a premixed mode where air and fuel are mixed before entering the combustor. The underlying principle is to supply the combustion zone with a completely homogenous, lean mixture of fuel and air. DLN combustor technology generally consists of hybrid combustion, combining diffusion flame (for low loads) plus DLN flame combustor technology (for high loads). Due to the flame instability limitations of the DLN combustor below approximately 50 percent of rated load, the turbine is typically operated in a conventional diffusion flame mode until the load reaches approximately 50 percent. As a result, NO_X concentrations rise when operating under low load conditions, yet the mass emissions rate at low load is less than base load.[3]

Oxidation Catalyst. The NGCC Project will install and operate an oxidation catalyst to reduce CO, HC, and organic HAP emissions produced during the combustion process in the flue gas by oxidation.

[3] https://www.epa.gov/system/files/documents/2022-03/combustion-turbine-nox-technology-memo.pdf

The basic chemical reactions are:

$CO + ½ O_2 \rightarrow CO_2$
$C_nH_m + (n + m/4) O_2 \rightarrow n CO_2 + (m/2) H_2O$
$C_nH_mO + (n + m/4 - 0.5) O_2 \rightarrow n CO_2 + (m/2) H_2O$
$2H_2 + O_2 \rightarrow 2H_2O$

The oxidation catalysts are formulated with precious metals (e.g., platinum group metals) and are coated on flow-through metal monoliths for minimum backpressure and compact design. Multiple catalyst formulations allow the flexibility to target specific conversion requirements, exhaust temperatures, low SO_2 to SO_3 and NO to NO_2 conversions. Oxidation catalysts can provide greater than 90% destruction of CO, VOCs, formaldehyde, and other toxic compounds.[4] See Section 5.3 of Appendix B for the methodologies used to calculate the control efficiencies used for this NGCC Project.

The catalytic oxidation of available SO_2 to SO_3 in the exhaust gases as it passes through the oxidation catalyst is usually 10 percent. The chosen conversion of SO_2 to SO_3 for a CO catalyst used in LG&E's proposed combined cycle unit is also 10 percent.[5]

SCR System. SCRs are used extensively in power generation applications including coal, oil, and combined cycle power plants. SCR is a post-combustion emission control technique whereby aqueous ammonia is vaporized and injected into the combustion exhaust gases before they pass through a catalyst bed. In the presence of the catalyst, NO_2 and NO (NO_X) react with oxygen and ammonia to produce nitrogen and water.

The basic chemical reactions are:

$2 NO + 2 NH_3 + ½ O_2 \rightarrow 2 N_2 + 3 H_2O$
$2 NO_2 + 4 NH_3 + O_2 \rightarrow 3 N_2 + 6 H_2O$

Small amounts of ammonia that are not consumed in the reaction result in low levels of ammonia stack emissions, known as ammonia slip. Each vendor based their emissions rates assuming no more than 5 ppmvd ammonia slip.[6]

The performance of an SCR system depends primarily on the temperature of the exhaust gas as it passes through the catalyst. Although catalyst formulations have provided a continuum of temperature ranges, these are typically described by three temperature ranges for optimal NO_X reduction. A "normal" catalyst operates well at approximately 650°F, a "mid-range" catalyst operates well between 800 and 900°F, and a "hot" catalyst (generally zeolite based) can operate above a temperature of 1,100°F, although the effectiveness of NO_X removal declines as a function of the exhaust gas temperature. Conventional vanadium/titanium catalysts are commonly used in SCR applications and have an optimal operating temperature in the 600 to 750°F range. Temperatures above 900°F can cause permanent damage to vanadium/titanium catalysts, thus requiring the use of high temperature zeolite catalysts and/or air tempering systems that can reduce exhaust gas temperatures prior to introduction into the catalyst. The application of SCR for the combined cycle plant is more straightforward because the SCR reactor is located

[4] https://www.jmsec.com/fileadmin/user_upload/pdf/brochures/jmsec_gas_turbine_oxidation_catalyst.pdf

[5] Page 6-4 of *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update.* EPRI, Palo Alto, CA: 2018. 3002012398

[6] Due to the installation of this advanced DLN system on these next generation GTs, ammonia slip is estimated at 5 ppmvd as opposed to 2-3 ppmvd because there will be less molecules of NO and NO_2 to react with NH_3. {See Wien et. al., *Air Emissions Terms, Definitions and General Information*, GE Energy, GER-4249 (08/05)}

downstream of the GT itself, within the tube banks at an appropriate temperature region, near the 600-700 °F range, allowing for the use of "conventional" catalysts.

The catalyst used is typically stacked vertically with gas flow horizontally through the catalyst face. The catalyst has a much smaller pitch due to the limited particulate and plugging concerns and does not deactivate as rapidly due to minimal catalyst poisons in the flue gas.

This process requires additional equipment to store, vaporize, dilute, and mix the reagent prior to being injected into the system through the ammonia injection grid (AIG). The dosing device supplies the vaporized ammonia into the ammonia injection blower system. It controls the quantity of the reduction agent, depending on load and NO_X values. To monitor the amount of ammonia injected, LG&E will install an ammonia flow meter.

Aqueous ammonia (maximum concentration of 19%) will be stored on-site in a storage tank with a capacity of approximately 35,000 gallons. The aqueous ammonia storage tank is a pressure vessel that only vents in the event of an emergency, and thus the tank will not normally vent to the atmosphere.

The catalytic reaction of available SO_2 to SO_3 in the exhaust gases as it passes through the SCR catalyst range between 1 and 3 percent. One vendor recommended the use of a 2 percent conversion. The chosen conversion rate to SO_3 for this installation within the proposed combined cycle unit is 3 percent, which is conservative.[7]

2.3.2 Auxiliary Boiler (U24/E50)

The NG-fired Auxiliary Boiler will be permitted with a maximum heat input capacity of 99.9 MMBtu/hr; however, the prospective equipment vendors will size to suit their design and it is expected that a smaller boiler will ultimately be installed. The combustion system will be LNB with flue gas recirculation (FGR) with a required 10:1 turndown.

The auxiliary boiler will only serve process loads and will consist of the following:

- HRSG freeze protection (only required with the unit off-line and ambient with potential freezing)
- Unit starts under warm or cold start conditions. The auxiliary boiler steam will provide sparging steam to the HRSG and condenser as well seal steam for the steam turbine. After the combined cycle unit is up and running auxiliary steam is furnished by the HRSG (cold reheat) and the auxiliary boiler can be taken out of service.

Under the expected dispatch, the Auxiliary Boiler is only expected to operate at 25% utilization or less during periods of time where the NGCC Unit is active. However, LG&E is requesting that it be permitted to allow for a full load continuous operation schedule up to 8,760 hours per year to provide maximum operational flexibility.

2.3.3 Emergency Generator with Diesel-Powered Engine (U25/E51)

The NGCC Project will employ a 2,000 kW emergency generator system that will include a nominal 2,682 bhp compression ignition engine. Ultra-low sulfur diesel (ULSD) fuel with a maximum sulfur content of 0.0015 weight percent (or 15 ppm) will be used in the engine. Potential emissions are based on operating

[7] Page 6-5 of *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update.* EPRI, Palo Alto, CA: 2018. 3002012398

500 hr/yr in accordance EPA guidance, although, there are no hourly limits on an emergency engine when operating for emergency purposes.

2.3.4 Fuel Gas (Dewpoint) Heater (U26/E52)

A NG-fired Fuel Gas (Dewpoint) Heater with a maximum heat input of 15 MMBtu/hr will be used to heat the pipeline natural gas that will be introduced to the combustion turbines and duct burners. Although this heater will not be expected to operate continuously, LG&E is requesting that it be permitted to allow for a continuous operation schedule up to 8,760 hours per year.

2.3.5 Emergency Diesel-Driven Fire Pump Engine (IA4/IE28)

The NGCC Project will include a 400 bhp diesel-fired compression ignition engine for emergency purposes to supply energy to the emergency fire pump engine. ULSD fuel will be used in the engine. Potential emissions are based on operating 500 hr/yr in accordance EPA guidance, although, there are no hourly limits on an emergency engine when operating for emergency purposes.

2.3.6 Mechanical Draft Cooling Tower (IA5/IE24)

Steam exiting the steam turbine will be condensed via indirect heat transfer using cooling water provided a mechanical draft, eight-cell, back-to-back counter-flow wet cooling tower. Cooling tower drift will be minimized to 0.001% of the design recirculation rate or less using inherent drift eliminators. The cooling tower qualifies to be classified as an insignificant activity based on its low potential emissions.

2.3.7 Lube Oil System with Demister Vents (IA5/IE25)

The GT and ST will be equipped with an internal lube oil storage and distribution system. A small quantity of the lube oil present in the system will be vaporized due to the high operating temperatures inside the turbine systems, potentially resulting in VOC emissions from the lube oil systems. The GT will be equipped with a demister system to avoid lube oil loss to the atmosphere to the extent possible; however, a small quantity of lube oil will be emitted, as VOC from the lube oil demister vents. This process qualifies to be classified as an IA based on its low potential emissions.

2.3.8 Diesel Storage Tanks (IA5/IE26)

All diesel consumed by the emergency use engines will be ULSD diesel. The diesel driven emergency fire pump engine will have an integrated 440-gallon dual wall tank located within the fire pump enclosure. The standby generator engine will be furnished with a base mounted dual wall tank with a capacity of 4,000 gallons. These storage tanks serving the emergency use engines qualify to be classified as an insignificant activity (IA) based on their low potential emissions.

2.3.9 HVAC Heaters (Total 10 MMBtu/hr) (IA27)

LG&E plans to provision multiple natural gas-fired HVAC units within buildings that support the NGCC Project. The total combined heat input capacity of all small HVAC heaters is assumed to be 10 MMBtu/hr or less. For permitting purposes and to calculate potential emissions, the maximum combined heat input capacity is assumed.

2.4 Shutdown of Existing Operations

Aside from the construction of the new NGCC Unit, LG&E will be shutting down multiple existing emission units at Mill Creek. Table 2-1 lists the existing emission units that will be impacted by the planned project and the proposed date of the permanent shutdown, resulting in project emissions decreases, which are further discussed in Section 4.4.

Table 2-1. List of EUs to be Shutdown with NGCC Project at Mill Creek Generating Station

Emission Unit	Emission Point	Emission Point Description	Control ID(s)	Control Description	Release ID(s)	Project Impacts
U1	E1	Unit 1 Boiler (3,085 MMBtu/hr)	C1, C26, C27	ESP, PAC Injection, DSI, PJFF, FGD	S33	Shutdown (12/2024)
U1	E2	Four Coal Silos; Four Coal Mills	C3	Centrifugal Dust Collector	S5	Shutdown (12/2024)
U2	E3	Unit 2 Boiler (3,085 MMBtu/hr)	C4, C27, C28	ESP, PAC Injection, DSI, PJFF, FGD	S33	Shutdown (4/2027)
U2	E4	Four Coal Silos; Four Coal Mills	C4	Centrifugal Dust Collector	S6	Shutdown (4/2027)
U9	E16	Flyash Transfer Bin with Two Separators for Units 1 & 2	C19	Baghouse	S17, S24, S25	Shutdown (4/2027)
U16	E40a-f	Sorbent Storage Silos (two of the six will be retired with MC1 and MC2)	C32a-f	Bin Vent Filters	S35a-f	Shutdown (12/2024) (4/2027)
U17	E41a-f	PAC Storage Silos (two of the six will be retired with MC1 and MC2)	C33a-f	Bin Vent Filters	S36a-f	Shutdown (12/2024) (4/2027)
IA5	IE14a	Cooling Tower for Unit 2	--	--	Fugitive	Shutdown (4/2027)
IAz8		Emergency Vent for U1 and U2 Boilers			Fugitive	Shutdown (4/2027)

Some existing units will remain operational (with no physical changes or changes to their method of operation) after the construction of the NGCC Project. The construction of the new NGCC Project will either have no impact on the utilization, method of operation, or emissions from these existing units, or in certain cases, will cause a decrease in utilization and emissions. The existing emission units that fall into one of these categories include:

- Unit 3 and Unit 4 Coal Boilers
- Raw material storage and handling units
- Waste/secondary material storage and handling
- Raw material mixers and crushers
- Cooling towers for Units 3 and 4
- Emergency use internal combustion engines
- NG-fired process heaters
- Gasoline dispensing and storage tank(s)
- Diesel dispensing and storage tank(s)
- Miscellaneous organic liquids tanks

- Landfill material handling and wind erosion fugitives
- Paved and unpaved roads

Emissions from these existing emission units are not discussed in Section 3 because these units will be unaffected (physically) by the proposed project.

3. EMISSIONS CALCULATION METHODOLOGIES AND SUMMARY

This section summarizes the emission calculation methodologies for the emission sources that comprise the proposed NGCC Project. Within each emissions unit section, the methods used to calculate emissions are discussed, followed by a summary of the emissions estimates for the specific unit and, in the case of the GT, the mode of operation. The NGCC Project's annual potential emissions for regulated NSR pollutants and HAPs are summarized in Table 3-2. These potential emissions are used as the basis for determining applicability of the project with respect to applicable regulatory requirements, which is discussed subsequently in Sections 4 and 5.

A more detailed set of documented emission calculations is presented in Appendix B of the application for all the new emission units that are part of the NGCC Project, which are listed below. The nomenclature for the emission unit and emission point IDs shown below are placeholders based on the next sequential numbers in the facility's current emission unit inventory and can be finalized by APCD upon its review of the application.

EU ID/EP ID	Description
• U23/E49a-e	EGU Unit 5 Gas Turbine with HRSG/Duct Burners
• U24/E50	Auxiliary Steam Boiler
• U25/E51	2 MW Diesel Emergency Generator Engine
• U26/E52	Fuel Gas (Dewpoint) Heater
• IA4/IE28	400 HP Emergency Diesel Driven Fire Pump Engine
• IA5/IE24	Mechanical Draft Cooling Tower (8 Cells)
• IA5/IE25	Lube Oil System with Demister Vents
• IA5/IE26	4,000 and 440 Gallon Diesel Storage Tanks
• IA5/IE27	HVAC Heaters (Total 10 MMBtu/hr)

3.1 Unit 5 Gas Turbine with HRSG (U23/E49a-e)

The primary emissions units for the NGCC Project are the NG-fired GT and HRSG, which includes DBs. The following subsections present the maximum hourly emissions during steady-state operations and startup/shutdown (SU/SD) events, as well as the total annual emissions including SU/SD emissions.

3.1.1 GT/DB Emissions from Steady State Operations

Normal or steady-state operation of a GT is characterized as continuous operation at loads generally in the 35 to 100% range (over the range at which emissions compliance is achieved). The GT may be operated at base load (100% operating load for the current ambient conditions) up to 8,760 hours per year with or without duct firing.

Heat input to a gas turbine varies as a function of the fuel (type, composition, and quality), ambient temperature, relative humidity, EC operation, and DB operation. Maximum heat input and maximum emissions rates typically occur at 100 percent load and the minimum design ambient temperature (i.e., -18°F). As explained in more detail in Section 4 of Appendix B, while the GT/DB can achieve a maximum heat input capacity of 4,216 MMBtu/hr (for Vendor A Case 1 for GT only at -18°F and 100% of baseload), the potential emissions used 4,157 MMBtu/hr (or 3.925 MMscf/hr) as the maximum simulated heat input capacity.

LG&E's proposed baseload NGCC Unit is almost entirely capable of converting the latent heat from the GT exhaust to steam in the HRSG without additional DB firing. In their equipment quotes, each prospective vendor only presented a few situations that require operation of the DBs, such as periods of time in the summer months to provide supplemental heat input capacity with the goal of ensuring the same MW generation as the winter months. The maximum heat input capacity from all three vendors was 296 MMBtu/hr (HHV) for the DB.

3.1.1.1 NO_X, CO, VOC, and PM Emissions

Similar to the heat input capacity, emissions from a gas turbine are also a function of the fuel (type, composition, and quality), ambient temperature, relative humidity, EC operation, and DB operation, but they additionally are affected by inherent controls, add-on controls, chemical conversions, and other miscellaneous factors. As documented in Sections 4 and 5 in Appendix B, maximum hourly controlled and uncontrolled emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, ammonia (NH_3), and formaldehyde for the proposed gas turbine rely on the vendor operational data and LG&E's vendor guarantee requirements for the NGCC Unit, which are listed in Table 3-1. Emissions factors for these pollutants were calculated as the maximum hourly emissions rate divided by 4,157 MMBtu/hr (equivalent to 3.925 MMscf/hr of NG combustion). Annual controlled emissions of NO_X, CO, and VOC used these same maximum simulated heat input capacities times the emissions factor times 8,760 hr/yr.

Table 3-1. GT/HRSG – Basis of Pollutant Emissions Rates

Pollutant	Emissions Basis
NO_X	2 ppmvd @ 15% O_2
CO	2 ppmvd @ 15% O_2
VOC	1-2 ppmvd @ 15% O_2
PM_{10}/$PM_{2.5}$	8-23.3 lb/hr
Formaldehyde	0.091 ppmvd @ 15% O_2
NH_3 slip	5 ppmvd @ 15% O_2

Source: Maximum of Vendor A, B, or C

The gas turbine unit will continue to comply with the presented emission rates irrespective of ambient weather conditions at all loads above MECL. Any emissions resulting from SU/SD operations are described in Section 3.1.2. Information regarding inherent and add-on controls used in the GT/HRSG system were previously explained in Section 2.3.1.

For NO_X, a nominal control efficiency (CE) of 90% for the SCR was selected for purposes of defining a conservatively (high) uncontrolled emission factor. This CE is not constant and not an equipment guarantee as it will normally range between 75% and 91% depending on available nitrogen content and GT combustor design/operation. For CO and VOC (and other organic HAPs), a nominal CE of 90% and 50%, respectively, for an oxidation catalyst was selected for purposes of defining the uncontrolled emission factors.

3.1.1.2 SO_2 and H_2SO_4 Emissions

Annual emissions of SO_2 and H_2SO_4 mist were based on a maximum pipeline NG sulfur content and additional factors to account for chemical conversions. For SO_2, all vendors used an expected maximum sulfur content for the pipeline gas of 0.5 grains (gr)/100 standard cubic feet (Cscf). In actuality, based on actual measurements of the pipeline gas consumed by Mill Creek Generating Station, the highest sulfur measured in the last 5 years was only 0.019 gr/Cscf. The SO_2 emissions are nonetheless based on a sulfur content of 0.5 gr/Cscf and 100% conversion from sulfur to SO_2. In reality, the total SO_2 emissions will be less due to the fact that some SO_2 further converts to SO_3, which can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. For simplicity, the potential emissions of SO_2 do not account for these further reductions and thus the emission estimates are conservative.

The conversion of SO_3 to H_2SO_4 mist and condensable PM (sulfates and nitrates) is influenced by the sulfur content in the pipeline NG, ambient temperature, relative humidity, EC operation, DB operation, oxidation over the CO catalyst, oxidation within the SCR, available moisture, ammonia slip concentration, acid dew point, and other factors. The hourly conversion used in the potential emissions calculations for permitting purposes conservatively assumes a 10% conversion in the GT/DB plus 3% conversion from the SCR plus 10% from CO catalyst (i.e., 23% total), consistent with the approach of the following citation, "*Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update*. EPRI, Palo Alto, CA: 2018. 3002012398, Pages 6-4 & 6-5 ", where the total conversion to H_2SO_4 mist assumes 10% conversion for GT/DB + 3% for SCR + 10% for CO catalyst.

3.1.1.3 Formaldehyde and HAP Emissions

Controlled formaldehyde emissions are calculated based on an emissions guarantee of 91 parts per billion by volume, dry (ppbvd) @15% O_2, which is also equivalent to the applicable standard in NESHAP Subpart YYYY, 40 CFR §63.6100. This concentration was then converted to a pound per MMBtu emissions factor based on Reference Method (RM) Method 19 determination of the dry F factor (Fd) used for natural gas combustion. LG&E chose to use Vendor A's derived Fd at ~8638 dscf/MMBtu, which was derived from RM 19 equations 19-13 through 19.15. The uncontrolled emissions factor for formaldehyde was obtained from Table 3.1-3 of the U.S. EPA's AP-42 Chapter 3, Section 3.1 *Stationary Gas Turbines*.[8] As a result, the estimated control efficiency for formaldehyde is 68%.

The GT's uncontrolled emission factors for HAPs other than acetaldehyde were also based on Table 3.1-3 of AP-42 as well. The background document supporting this chapter provided controlled emissions factors when using a CO catalyst for acetaldehyde, acrolein, and benzene.[9] See Section 5.3.3 of Appendix B for additional details and for the derivation of control efficiencies.

Even though the DB will be used sparingly over the summer months and because there is no restriction on its use, LG&E also provides the standard uncontrolled emissions factors obtained from Tables 1.4-2, 1.4-3, and 1.4-4 of the U.S. EPA's AP-42 Chapter 1, Section 1.4 *Natural Gas Combustion*.[10] A 50 percent control efficiency from the oxidation catalyst was applied to calculate the controlled emission factors for the organic HAPs. See Section 5.3.4 of Appendix B for additional details.

For pollutants where there was overlap between the Sections 1.4 and 3.1 of AP-42, the highest emissions factor was used to derive the potential emissions from the GT/DB system. As shown in Section 3 of Appendix B, using the DB's uncontrolled emission factor for hexane at 1.8 lb/MMscf to estimate the GT/DB's annual emissions results in an annual potential to emit of 15.47 tons per year (tpy) compared with the next highest HAP at 3.95 tpy for formaldehyde, which is an expected pollutant from this type of installation.

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[8] https://www.epa.gov/sites/default/files/2020-10/documents/c03s01.pdf

[9] https://www.epa.gov/sites/default/files/2020-10/documents/b03s01.pdf

[10] https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

3.1.1.4 GHG Emissions

GHG emissions are estimated based on proposed equipment specifications as provided by the prospective vendors and the default emission factors in the U.S. EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas). According to 40 CFR §52.21(b)(49)(ii), GHG emissions for PSD applicability must show carbon dioxide equivalent (CO_2e) emissions calculated by multiplying the mass of each of the GHGs by the gas's associated global warming potential (GWP), which are specified in Table A-1 to Subpart A of 40 CFR Part 98.

3.1.2 GT/DB Emissions from Startup and Shutdown Operations

For the proposed NGCC Unit, startup will be defined as the period between the commencement of ignition and when the combined-cycle unit reaches emissions compliance (i.e., 2.0 ppmvd CO and NO_X at 15% O_2 at the stack).

The NGCC Unit equipment package from each of the prospective vendors each has its own unique features that allow each NGCC Unit to quickly achieve emissions compliance during a cold, warm, or hot start event. The following provides the underlying basis for each vendor's pound per event emission estimates.

- Cold starts (CS) are preceded by over 72 hours of shutdown.
  - Expected maximum annual CS events = 5 events/yr over a 40 to 70 minutes ramp up time

- Warm start (WS) or "non-cold startup" are preceded by a shutdown between 8 and 72 hours. A value of 48 hours is used.
  - Expected maximum annual WS events = 45 events/yr over a 30 to 60 minutes ramp up time

- Hot starts (HS) are defined as taking place within 8 hours of the previous shutdown.
  - Expected maximum annual HS events =100 events/yr over a 21 to 35 minutes ramp up time

- Shutdowns (SD) occur for 12-21 min and the total number of these events is the sum of all cold, warm, and hot SUs.
  - Expected maximum annual SD events = 150 events/yr over 12 to 21 minutes until emissions cease

These assumptions were provided by each vendor, and they are neither guaranteed, nor are they intended to be included in the permit as emissions limits or operational restrictions. While the SU/SD assumptions provide valuable information, from an air permitting perspective, it is more important to focus on the total mass of emissions per event.

NO_X, VOC, CO, and PM emissions vary during SU/SD events; however, emissions of other pollutants do not vary substantively during these events (compared to those during normal steady-state operations). Therefore, only emissions of NO_X, VOC, CO, and PM are separately defined for SU/SD events. The total emissions for each event are provided in Sections 4.1 through 4.3 in Appendix B. As shown in Section 5.5.1 of Appendix B, the emissions factors in pounds per event for the regulated NSR pollutants are based on the highest vendor-provided lb/event. As an example, as documented there, using these methodologies, the total emissions from NO_X estimated for 150 SU/SD events in a year adds an additional 19.5 tpy to the NGCC Project potential emissions.

This methodology of using the maximum of each vendor's individual CS, WS, HS, and SD event emissions value for each pollutant adds an additional level of conservativeness.

3.1.3 GT/DB Annual Emissions

Tables in Sections 4.1 to 4.3 in Appendix B, provide maximum hourly pollutant emissions rates for the GT/HRSG unit based on three different loads and three different ambient temperatures, including EC and DB operation. Also provided are the outliers with the highest emissions rate. In all cases, the partial loads resulted in lower hourly emissions rates. A summary of the cases provided by each vendor that were evaluated for defining potential emissions is as follows.

- Vendor A
  - GT loads at 30%, 32.3%, 33.3%, 36.1%, 41.5%, 63.9%, 74.3%, 75%, and 100%
  - Inlet air temperatures of -18, 15, 45, 57, 90, and 106°F
  - Relative humidity (RH) of 40, 50, 55, 60, and 70
  - Ambient pressure of 14.257 pounds per square inch absolute (psia)
  - Evaporative Cooler (EC) on at 90-106°F and 40-50% RH
  - DB on at 90-106°F and 40-50% RH
  - 1 x 1 Combined Cycle Operation Only
  - No ability to by-pass controls

- Vendor B
  - GT loads at 100%
  - Inlet air temperatures of -18, 15, 45, 57, 59, 90, and 106°F
  - Ambient pressure of 14.245 psia
  - EC on at 59-106°F and 40-60% RH
  - DB on at 90°F and 50% RH
  - 1 x 1 Combined Cycle Operation Only
  - No ability to by-pass controls

- Vendor C
  - GT loads at 35%, 75%, and 100%
  - Inlet air temperatures of -18, 15, 45, 57, 90, and 106°F
  - Ambient pressure of 14.225 psia
  - EC on at 90-106°F and 40-50% RH
  - DB on at 90°F and 50% RH
  - 1 x 1 Combined Cycle Operation Only
  - No ability to by-pass controls

Given the range and breadth of the cases presented, there are numerous ways to derive the annual potential emissions for the GT. As shown in Section 4.4 of Appendix B, four different simulated annual operating profiles were evaluated for defining potential emissions:

- Profile 1 calculates the annual emissions using 8,760 hours at the highest hourly emissions rate at the average ambient temperature. In every case, DBs will not be necessary to generate the rated output.
- Profile 2A calculates the annual emissions with 2,000 hr/yr of operation at 15°F, 4,760 hr/yr at 57°F, and 2,000 hr/yr at 90°F. The DBs and EC only kick in during the summer months. Although it artificially elevates the potential emission rate, for simplicity and conservatism, the total hours do not subtract periods of non-operation between a shutdown and a startup, nor do the total hours exclude the total time of GT operation during the events.

- Profile 2B is the same as 2A except 127 hours of time for SU/SD events is subtracted. Again, this case does not subtract periods of non-operation between a shutdown and a startup.[11]
- Profile 3 is the maximum hourly emissions rate for any case multiplied by 8,760 hr/yr.

As shown in Sections 4.5 and 4.6 of Appendix B, in reviewing the calculated annual emissions for the worst-case operating profiles, LG&E has chosen to represent the potential emissions for the GT/DB based on Profile 2A. Profile 3 is not used because it is not practically realistic and could never occur in practice. While Profile 2A is also extremely conservative, in that it does not subtract for SU/SD hours (which is done in Profile 2B), the differences are not significant. Profile 2A, which considers the differences for cold and hot seasons, also predicts slightly higher potential emissions than the baseload case at the average ambient temperature. Thus, it is conservative but reasonable to use annual emissions for Profile 2A to define the potential to emit (PTE).

Based on the defined PTE values (tpy), the equivalent hourly average emission rates (lb/hr) for each pollutant can be calculated. An emission factor in terms of lb/MMBtu can then be calculated based on the vendor-provided heat input associated with the case for which the PTE value is derived. See Section 4.4 of Appendix B, which provides the underlying heat input rate.

For example, steady-state stack exhaust emissions and the emissions factor of NO_X are calculated as follows.

> Profile 2A NO_X (lb/hr) = 136.8 tpy × 2,000 lb/ton / 8,760 hr/yr = 31.23 lb/hr for Vendor B (at 3,850 MMBtu/hr and 3,636 MMscf/hr)
> NO_X Emission Factor (lb/MMBtu) = 31.23 lb/hr / 3,850 MMBtu/hr = 0.00811 lb/MMBtu
> NO_X Emission Factor (lb/MMscf) = 31.23 lb/hr / 3.636 MMscf/hr = **8.589 lb/MMscf**
>
> Yet, Maximum Natural Gas Fuel Consumption is for Vendor A = 4,157 MMBtu/hr (maximum for any pollutant) / 1,059 MMBtu/MMscf = 3.925 MMscf/hr
> NO_X (lb/hr) = **8.589 lb/MMscf** × 3.925 MMscf/hr = 33.71 lb/hr

Regarding the SU/SD events, each vendor provided NO_X, CO, VOC, and $PM/PM_{10}/PM_{2.5}$ emissions over each event based on the anticipated maximum number of events that might happen over 12 months. As explained above, using the average of the range for all three vendors, these events would span a total of 127 hours per year. And, if the time in between these events was accounted for in the calculations, the GT/DB would not be operating (or emitting) for 3,447 hr/yr (i.e., 5 cold SU x 72 average hours down + 45 warm SU x 48 average hours down + 100 hot SU x 8 average hours down). Thus, basing the potential emissions on 8,760 hr/yr of operation and then additionally adding the emissions from the SU/SD events yields a conservatively high emission rate. However, this approach is done specifically to avoid the need to establish enforceable individual operating limits around the frequency or duration of SU/SD events in the permit.

Annual potential emissions based on the methodologies described for both the GT/DB and SU/SD events are shown in Section 5.7 in Appendix B.

[11] 127 SU/SD hrs = (5 cold SU events × average of 40 & 70 min cold SU + 45 warm SU events × average of 30 & 60 min warm SU + 100 hot SU events × average of 21 & 35 min hot SU + 150 SD events × average of 12 & 21 min SD) × 60 min/hr

3.2 Ancillary Equipment

There are several emissions units that are part of the NGCC Project and support the operation of the GT. Descriptions of the emissions calculations for the ancillary equipment are provided in the following subsections.

3.2.1 Auxiliary Boiler (U24/E50) and Fuel Gas (Dewpoint) Heater (U26/E52)

Potential emissions from the Auxiliary Boiler and Fuel Gas (Dewpoint) Heater are estimated based on LG&E's vendor requirements, pipeline natural gas specifications, and published AP-42 emissions factors. Annual potential emissions for the Auxiliary Boiler and the Fuel Gas (Dewpoint) Heater are documented in Sections 6.3 and 7.3 of Appendix B, respectively.

3.2.2 Emergency Use Diesel-Fired Engines

The emergency diesel-fired fire water pump engine (IA4/IE28) and the emergency diesel-fired engine for the planned emergency generator engine (U25/E51) will meet the emissions requirements specified in Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII). Emissions of regulated NSR pollutants from the engines are based on either 40 CFR Part 60, Subpart IIII emissions limits (which points to U.S. EPA Tier 2 emissions limits for the generator), and certified emissions data from a representative manufacturer (CAT for the emergency generator engine and John Deere for the emergency fire water pump engine), or AP-42 emissions factors for criteria pollutants and HAPs.

Annual potential emissions based on these methodologies for the emergency generator are shown in Section 10.3 and annual potential emissions for the emergency fire water pump engine are shown in Section 11.3 in Appendix B. The emergency fire pump engine qualifies to be classified as an insignificant activity based on its low potential emissions. LG&E presumes that APCD will add the fire pump engine to Insignificant Activity Group IA4 and an ID of IE28 is proposed.

3.2.3 Storage Tanks and Organic Losses

A 4,000-gallon, dual walled, above ground, ULSD fuel storage tank will be located in the base of the emergency generator engine. In addition, a 440-gallon, fire-rated, above ground, ULSD fuel storage tank will be used for the emergency fire water pump engine. The two ULSD fuel storage tanks are considered sources of VOC emissions.

Standing and working losses of VOCs were calculated for both diesel storage tanks using TankESP®, which calculates working and breathing losses using the most current version of AP-42 Section 7.1. – *Organic Liquid Storage Tanks*.[12] Annual potential VOC emissions from the 4,000-gallon and 440-gallon diesel tanks are estimated to be 1.98 and 0.27 lb/yr, respectively (see Section 13.2 in Appendix B).

Another potential source of VOC emissions is the lube oil system used for the GT and ST. The GT and the ST will include a lubricating oil sump with a system capacity of approximately 10,000 gallons. The CT and ST will also be equipped with lubricating oil vents, which include electrostatic precipitators/demisters for lubricating oil mist control. Use of low-volatility/low-VOC oil and a low consumption rate of lubricating oil in the CT and ST will result in insignificant/negligible VOC emissions from storage of the lubricating oils. The working losses conservatively assume that all lube oil consumed/replaced will evaporate and contribute to

[12] https://www.trinityconsultants.com/software/tanks/tankesp

VOC emissions. Annual potential VOC emissions from the lube oil demister vents are shown in Section 12.2 of Appendix B.

3.3 Potential Emissions Summary

A summary of the calculated potential emissions for the NGCC Project is provided in Table 3-2. Detailed emission calculations including emission factors and references are provided in Appendix B of the permit application report.

Table 3-2. NGCC Project – Total Potential Emissions from New Emission Units

Pollutant	Potential to Emit (tpy)
PM	104.0
PM_{10}	102.9
$PM_{2.5}$	102.0
NO_X	199.9
CO	161.4
VOC	51.6
SO_2	25.3
H_2SO_4	8.7
Lead	0.0089
CO_2e	2,214,149
Hexane (HAP)	16.4
Formaldehyde (HAP)	4.0
Total HAPs	26.0
NH_3	122.8

4. NSR APPLICABILITY ASSESSMENT

This section addresses the methodology used to define the emissions changes from the proposed NGCC Project and assesses applicability of the NSR permitting regulations.

4.1 PSD/NA-NSR Applicability Background

The NSR program was designed to protect public health and welfare from the effects of air pollution and to preserve and/or improve air quality throughout the nation. The NSR program requires certain stationary sources of air pollution to obtain air pollution permits prior to beginning construction. Construction of new sources with emissions above statutory thresholds, and modifications of existing sources emitting above those thresholds or that increase emissions of regulated NSR pollutants by more than the major modification thresholds specified in the NSR regulations are subject to NSR permitting requirements.

The major source NSR regulations encompass two distinct programs that each have unique requirements for new or modified sources. The applicability of these two programs depends on the area's attainment status with respect to the NAAQS. The PSD program, based on requirements in Part C of Title I of the Clean Air Act (CAA), applies to pollutants for which the area is not exceeding the NAAQS (areas designated as attainment or unclassifiable) and to regulated NSR pollutants for which there are no NAAQS. The nonattainment NSR (NA-NSR) program, based on Part D of Title I of the CAA, applies to pollutants for which the area is not meeting the NAAQS (areas designated as nonattainment).

Mill Creek Generating Station is located in Jefferson County, Kentucky, which is currently designated by the U.S. EPA as an unclassified/attainment area for all criteria pollutants, except ozone. For ozone, Jefferson County is designated as a marginal nonattainment with respect to the 8-hour ozone NAAQS promulgated in 2015.[13] It is located in the portion of Jefferson County that was redesignated as a maintenance area for the 2010 SO_2 NAAQS on September 8, 2020.[14] As such, both PSD and NA-NSR permitting requirements are potentially applicable to the proposed project.

4.2 Existing Source Classification

4.2.1 PSD Permitting Program Source Classification

APCD has a State Implementation Plan (SIP)-approved PSD program encompassed in Regulation 2.05. This regulation adopts the July 15, 2017 edition of the federal PSD regulations at 40 CFR §52.21 by reference with exceptions shown in Section 1 of Regulation 2.05.

The PSD permitting program requirements apply to the construction of any new *major stationary source* (as defined in 40 §CFR 52.21(b)(1)) **or** any project at an existing major stationary source in an area designated as attainment or unclassifiable that is a major modification. A stationary source is a major source if the potential to emit for a specific pollutant equals or exceeds the major source threshold for *regulated NSR*

[13] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-81/subpart-C/section-81.318 and https://www3.epa.gov/airquality/greenbook/anayo_ky.html

[14] https://www.federalregister.gov/documents/2020/08/06/2020-15598/air-plan-approval-and-designation-of-areas-kentucky-redesignation-of-the-jefferson-county-2010

pollutants.[15] The regulated NSR pollutants of relevance to the existing Mill Creek Generating Station operations and the NGCC Project are NO_X, CO, SO_2, PM, PM_{10}, $PM_{2.5}$, VOC, lead, and H_2SO_4 mists.

For projects involving increases in GHG emissions, the mechanism for triggering PSD review is different from other regulated NSR pollutants. For a project to trigger PSD review for GHGs, GHGs must first become *subject to regulation* to be treated as a regulated NSR pollutant that can fall under the PSD requirements.[16] A physical change or change in the method of operation at a facility that results in an emissions increase of a non-GHG pollutant exceeding the significance thresholds **and** an emissions increase of GHG exceeding 75,000 tpy CO_2e (for the project alone and on a net basis considering contemporaneous emissions increases and decreases) would make the GHG emissions increase from the project subject to regulation and would require PSD review for the GHG emissions from the new units associated with the proposed project.[17]

The threshold for defining a facility as a major stationary source under the PSD permitting program is 250 tpy of any regulated NSR pollutant unless the facility belongs to one of 28 specially named source categories (List of 28), in which case the major stationary source threshold is 100 tpy.[18,19] Existing operations at Mill Creek Generating Station, classified under SIC Code 4911, "Electric Services", include "fossil fuel-fired steam electric plants," which is a named category on the List of 28. As such, the major source threshold for the PSD program is 100 tpy. The potential emissions of at least one regulated NSR pollutant currently exceeds 100 tpy; therefore, Mill Creek Generating Station is classified as an existing major stationary source under the PSD program.

4.2.2 Nonattainment NSR Program Source Classification

APCD has a Board-approved nonattainment NSR program that is contained in Regulation 2.04, which was last updated on March 16, 2022.[20] Pursuant to Paragraph 2.1 of Regulation 2.04, NA-NSR applies to any new major stationary source or major modification that is major for the pollutant for which the area is designated nonattainment under section 107(d)(1)(A)(i) of the CAA, if the stationary source or modification would locate anywhere in the designated nonattainment area. Different pollutants, including individual precursors, are not summed to determine applicability of a major stationary source or major modification.

For Jefferson County, the major stationary source threshold for all nonattainment pollutants (and their precursors) is 100 tpy.[21] Since Jefferson County currently is only designated nonattainment for ozone, emissions of its defined precursors, NO_X **or** VOC, must be compared to the 100-tpy threshold. Other pollutants are covered under the PSD program.

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[15] *Regulated NSR Pollutant* defined in Regulation 2.05, Section 1, and 40 CFR §52.21(b)(50)

[16] "Subject to regulation" is defined in 40 CFR §52.21(b)(49).

[17] 40 CFR §52.21(b)(49)(iv)

[18] 40 CFR 52.21(b)(1)(i)(a)

[19] Being a List of 28 source says nothing about whether a facility is classified as a minor or major source under PSD or whether it is subject to PSD permitting requirements. Being on the List of 28 imparts no particular regulatory requirements or permitting obligations. It only defines what the major source threshold is for a facility in an attainment area.

[20] https://louisvilleky.gov/air-pollution-control-district/document/regulation-204-version-8

[21] There are no specially defined source categories under the Nonattainment NSR program as there are under the PSD program, being excluded from which would result in a 250 tpy major source threshold.

Similar to the rationale provided in the PSD section, potential emissions of NO_X and VOC currently exceed 100 tpy; therefore, Mill Creek Generating Station is classified as an existing major stationary source under the NA-NSR program.

Therefore, with respect to the NA-NSR permitting program, NA-NSR requirements could potentially apply to the NGCC Project for emissions of both NO_X and VOC. VOC which is regulated as a precursor to ozone is only potentially subject to NA-NSR requirements. However, NO_X, which is both subject to a dedicated NAAQS (for NO_2) and is regulated as a precursor to ozone, is potentially subject to both PSD and NA-NSR requirements.

4.3 NSR Applicability Analysis Methodology

4.3.1 Defining the Project

The proposed NGCC Project involves the new installation and operation of the new NGCC Unit to replace the capacity leaving with the shutting down the Mill Creek Units 1 and 2 boilers. The existing Units 3 and 4 boilers and the shared material storage and handling operations will be retained and are not being modified by the planned project. However, there will be attributable emissions decreases from certain coal handling operations due to reduction on overall coal usage with the shutdown of Units 1 and 2. No other emission units will have any emissions increases or decreases caused by the NGCC Project. The existing electric generation and transmission assets supporting Units 1 and 2 will remain in place; however, certain modifications/enhancements will be made to accommodate the NGCC Unit.

Since the new Unit 5 Gas Turbine with HRSG and its auxiliary support operations will be under the same common control and ownership, have the same SIC code, and be constructed and operated within the same property boundary, construction of NGCC Project is a modification to an existing major stationary source.

4.3.2 Existing versus New Emission Units

For purposes of calculating project-related emissions increases (labeled herein as project emissions increase or PEI), different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether a source affected by a proposed project is considered a new or existing emission units.

40 CFR §52.21(b)(7) defines emission units as any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an *electric utility steam generating unit* (defined in 40 CFR §52.21(b)(31)). Similar definitions exist within Regulation 2.04. For purposes of this section, there are two types of emissions units:

> *(i) A **new emissions unit** is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.*
>
> *(ii) An **existing emissions unit** is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.*

The GT/DB, Auxiliary Boiler, Fuel Gas (Dewpoint) Heater, Cooling Tower, Emergency Engines, HVAC Units, Storage Tanks, and Demister Vents that are proposed with the NGCC Project are all considered new emissions units.

The Units 1 and 2 coal-fired boilers being shut down, along with their material handling, storage, and transfer operations (which will have an attributable reduction in utilization and emissions), qualify as existing units since they have been in operation for more than two years.

4.3.3 Two-Step Major Modification Determination Process

As Mill Creek Generating Station is classified as an existing major stationary source for PSD and NA-NSR, if the proposed project meets the definition of a *major modification* (specific to each regulated NSR pollutant), then the full PSD and NA-NSR permitting requirements apply for that pollutant. *Major modification* is defined at 40 CFR §52.21(b)(1) for PSD and paragraph 1.5 of Regulation 2.04 for NA-NSR:

> *"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant emission increase [Step 1] … of a regulated NSR pollutant … and a significant net emissions increase of that pollutant [Step 2] … [Step 1 & Step 2 added]*

Certain exemptions to the major modification definition exist that, if applicable, means a project does not require an emission increase assessment. The proposed project does not qualify for any of the established exemptions.

For NA-NSR and pursuant to paragraph 1.27 of Regulation 2.04, *significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is *significant* (as defined in paragraph 1.10 of Regulation 2.04) for that pollutant. For PSD and pursuant to 40 CFR 52.21(b)(40), *significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is *significant* (as defined in 40 CFR §52.21(b)(23)) for that pollutant.

For those pollutants with a *significant emission increases*, the net creditable emission increases and decreases over the contemporaneous period [as defined in 40 CFR §52.21(b)(3) and Paragraph 1.6 of Regulation 2.04] are estimated and the *net emissions increase* is calculated for comparison with the *significant* thresholds (as defined in 40 CFR §52.21(b)(23) and paragraph 1.10 of Regulation 2.04).

Net emissions increase (NEI) is defined by 40 CFR §52.21(b)(3) for PSD, and has similar language in paragraphs 1.6 and 2.2 of Regulation 2.04 for NA-NSR, as:

> *"Net Emissions Increase" means, with respect to any regulated NSR pollutant … the amount by which the sum of the following exceeds zero:*

(i) The increase in emissions … as calculated pursuant to 40 CFR §52.21(a)(2)(iv). [for existing units, calculated by actual-to-projected actual[22] *or actual-to-potential; for new units, calculated by actual-to-potential]*[23, 24]

(ii) Any other increases and decreases in actual emissions…that are contemporaneous with the particular change and are otherwise creditable. Baseline emissions for calculating increases and decreases…shall be determined as provided…

Step 1 is commonly referred to as the "project emission increases (PEI)" analysis as it accounts only for emissions related to the proposed project itself. If the emission increases estimated per Step 1 exceed the major modification thresholds, then the applicant may move to Step 2, commonly referred to as the 5-year netting analysis. The netting analysis includes all projects in the contemporaneous period for which a creditable emission increases or decreases occurred. If the resulting net emission increases exceed the major modification threshold, then NSR permitting requirements apply.

Historically, Step 1 emissions would not have accounted for proposed equipment shutdowns planned, requiring instead that such emission decreases be accounted for as part of the Step 2 analysis, along with any additional contemporaneous increases and decreases. However, in 2020, EPA promulgated the "Project Emissions Accounting" clarification, establishing that the Step 1 emissions can include decreases "provided they are part of a single project" and affirmed that a project can include a combination of new and existing units (i.e., hybrid).[25]

APCD has accepted and codified the EPA promulgated the "Project Emissions Accounting" clarification. APCD's PSD requirements in 40 CFR §52.21(a)(2)(iv)(g) includes the "sum of the difference" for all applicability tests, and the NA-NSR requirements have the same language at paragraph 2.2.7 of Regulation 2.04. As the proposed NGCC Project is being added and Units 1 and 2 coal-fired boiler operations are being shut down, LG&E included the emission decreases from these shutdowns in the Step 1 analyses. As is shown in the subsequent paragraphs, because the project emissions increases calculated in Step 1 are less than the major modification thresholds for all regulated NSR pollutants, an evaluation of the net emissions increase (i.e., Step 2) was not required and PSD and NA-NSR permitting requirements do not apply to this project. However, it is worth noting that if a Step 2 netting analysis was conducted, the applicability determination would be exactly the same.

[22] 40 CFR §52.21(a)(2)(iv)(c), Actual-to-projected-actual applicability test for projects that only involve existing emissions units, states: A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant …

[23] 40 CFR §52.21(a)(2)(iv)(d), Actual-to-potential test for projects that only involve construction of new emissions units, states: A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant …

[24] 40 CFR §52.21(a)(2)(iv)(f), *Hybrid test for projects that involve multiple types of emission units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the methods specified in subparts (a)(2)(iv)(c) and (d) of this paragraph as applicable … equals or exceeds the significant amount for that pollutant …*

[25] Federal Register Volume 85, No. 227, *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting,* Final Rule, pp. 74890-74909, published November 24, 2020. Quotation per p. 74893.

4.4 Components of Project Emission Increases

To calculate the project emissions increase, the difference between a future emission level (either potential emissions or projected-actual-emissions) and the baseline actual emissions must each be calculated. These components of the emission increase calculation formula are defined in the following sections.

4.4.1 Potential Emissions

For new emission units, the calculated project emissions increase is simply set to the future annual potential emission rate of the unit considering inherent physical and operational constraints on the production capacity of the equipment and any federally enforceable emissions/operating limitations, where applicable.

4.4.2 Baseline Actual Emissions (BAE)

For existing emission units being modified or affected, to determine the emission increases associated with the proposed project, baseline actual emissions are first defined. *Baseline Actual Emissions* (BAE) are defined in 40 CFR §52.21(b)(48) or by paragraph 1.35 of Regulation 2.04:

> *For an existing electric utility steam generating unit, baseline actual emissions means 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 either the date the owner or operator begins actual construction of the project. The Reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation…*

For a new emission unit covered in the project scope, the BAE are set to zero. For an *emission unit* that "has existed for less than two (2) years from the date the unit first operated", [26] the baseline emissions levels are set equal to "the unit's potential to emit."[27]

The baseline period can be selected on a pollutant-by-pollutant basis, but for a given pollutant, only one baseline period can be used across all new, modified, and associated emission units in the project scope. The baseline period selection process typically involves a review of historical production and emissions data over the previous 5 years at an existing electric utility steam generating unit to identify a historically representative period of 24-month rolling average production/annual emissions.

Since commercial operation for the Mill Creek Generating Station NGCC Unit is targeted for April 1, 2027, and 37 months are allocated for construction and commissioning, the presumed start of on-site construction is **March 1, 2024**. The 5-year period immediately preceding this date begins on March 1, 2019. Thus, for the NGCC Project the earliest baseline period available to select for each pollutant is the 24-month period ending February 2021 (i.e., March 2019 to February 2021).

The selected baseline period used for each pollutant along with documentation of the BAE (and thus the equivalent emission reductions for the project) are provided in Appendix B in Section 14 for Unit 1 & 2 Boilers, Section 15 for Coal Bunkers, Section 16 for Coal Handling, Section 17 for Flyash Transfer Bin, Section 18 for Sorbent and PAC Silos, and Section 19 for Unit 2 Cooling Tower**.**

[26] *Emission Unit* definition in 40 CFR §52.21(b)(7).

[27] 40 CFR §52.21(b)(48)(iii) and Section 1.35.3 of Regulation 2.04

4.4.3 Projected Actual Emissions (PAE)

Projected Actual Emissions (PAE) are defined by 40 CFR §52.21(b)(41)(i) and Paragraph 1.28.1 of Regulation 2.04:

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

For units in which the proposed projects would not change the potential to emit or the design capacity, an applicant sets the PAE for the following five years after authorization of the proposed project(s).

In determining PAE, pursuant to 40 CFR §52.21(b)(41)(ii)(a) and Paragraph 1.28.2.1 of Regulation 2.04, the source:

> *Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with {the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan}...*

For unmodified, associated units, future emissions are calculated by the same actual-to-projected actual procedure as other existing emissions units.

4.4.4 Additional Associated Emission Unit Increases

In addition to the emission increases from new or modified units, emission increases from associated emission units that may realize an increase in emissions due to a project must be included in the assessment of the project emissions increases.

4.5 Project Emission Increase Evaluation

As stated above, the NGCC Project will constitute a modification to an existing major stationary source, and involves new emissions units and existing emissions units. The procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being modified. Pursuant to 40 CFR §52.21(a)(2)(iv)(f)-(g) and Paragraph 2.2.6-7 of Regulation 2.04,

> (*f*) ***Hybrid test for projects that involve multiple types of emissions units.*** *A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference for all emissions units, using the method specified in paragraphs (a)(2)(iv)****(c)*** and ***(d)*** of *this section as applicable with respect to each emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).*
>
> *(g) The "sum of the difference" as used in paragraphs* ***(c)***, ***(d)*** and (*f*) *of this section shall include both increases and decreases in emissions calculated in accordance with those paragraphs.*

Paragraph (c) of 40 CFR §52.21(a)(2)(iv) references the **actual-to-projected-actual applicability test** for projects that only involve existing emissions units. A "significant emissions increase" of a regulated NSR pollutant is projected to occur if the sum of the difference between the PAE and the BAE for each existing emissions unit, equals or exceeds the significant amount for that pollutant.

Whereas (d) of 40 CFR §52.21(a)(2)(iv) references the **actual-to-potential test** for projects that only involve construction of a new emissions unit(s).

Therefore, for hybrid projects that involve existing and new emission units, such is the case with the NGCC Project, an actual-to-projected actual applicability test is used for the existing units and an actual-to-potential test is used for the new units. The sum of emission increases from these tests for all affected units associated with the project is the total project emissions increase (PEI) assessed against the significance thresholds in Step 1.

> PEI = Sum of differences of New EUs (PAE_i – BAE_i) + Sum of differences of Existing EUs (PAE_j – BAE_j) + Sum of differences of Unmodified EUs (PAE_k – BAE_k)

For a new emissions unit, PAE_i = PTE, and BAE is usually 0.0 tpy. For example, as shown in Section 2 in Appendix B, the "sum of the differences" for NO_X emissions from the GT/DB, a new emission unit, are as follow:

> $PAE_{U23/E49}$ = $PTE_{U23/E49}$ = 167.2 tpy
> $BAE_{U23/E49}$ = 0 tpy
> $PEI_{U23/E49}$ = 167.2 tpy PAE – 0 tpy BAE = 167.2 tpy for NO_X

For modified emissions units, PAE_i is the forecast of each emission unit's future actual emissions.[28] With the NGCC Project, there will be existing emissions units that are shut down or modified. For example, for the Unit 1 Coal Boiler, $PAE_{U1/E1}$ will be 0.0 tpy of NO_X since the projected actual emissions for a unit being permanently shut down are 0 tpy. The BAE for each of the existing emissions units (e.g., Unit 1, Unit 2, etc.) are documented in Sections 14 through 19 of Appendix B.

For example, the "sum of the differences" for NO_X emissions from the existing Unit 1 coal-fired boiler are as follow:

> $PAE_{U1/E1}$ = 0.0 tpy
> $BAE_{U1/E1}$ = 2,251 tpy is the 2-year average actual emissions in the baseline period (March 2019 through February 2021)
> $PEI_{U1/E1}$ = 0.0 tpy PAE – 2,251 tpy BAE = -2,251 tpy for NO_X

Unmodified existing emission units located upstream or downstream of new or modified emissions units in the project scope are addressed in the calculation of an emissions increase for the project if these unmodified units will experience a change in actual annual throughput/utilization due to the operation of the proposed new/modified units. This type of upstream/downstream emission unit is commonly referred to as an "associated" emission unit. For example, Coal Handling Equipment (U21) will not be modified as part of the project, but activity will be reduced in conjunction with shutdown of Units 1 and 2 Boilers. As a result,

[28] In a letter from Scott Pruitt, EPA Administrator to EPA Regional Administrators (December 7,2017), when a source performs a pre-project NSR applicability analysis in accordance with the procedure in the regulations, and follow the applicable recordkeeping and notification requirements, the source has met the pre-project source obligations. Unless there is clear error (e.g., source applies an incorrect SER), the projected actual emissions are not second-guessed. (https://www.epa.gov/sites/default/files/2017-12/documents/nsr_policy_memo.12.7.17.pdf)

there will be an emission decrease from these coal handling units associated with the project. The emission decrease is set to the BAE attributable to coal usage in the baseline period for the Unit 1 and 2 Boilers, as documented in Section 16 of Appendix B.

4.6 PSD/NA-NSR Applicability Summary

A detailed table documenting the potential emissions from new emission units on a unit-by-unit basis, the baseline actual emissions from shutdown and associated emission units on a unit-by-unit basis, and the overall calculated project emissions increase is provided in Section 2 of Appendix B. A summary showing the comparison of the project emission increases compared to the PSD and NA-NSR major modification thresholds are shown in Tables 4-1 and 4-2, respectively.

Table 4-1. NGCC Project Emissions Increases Compared with PSD Significant Emission Rates

Pollutant[1]	**"Step 1" Project Emissions Increase** (tpy)	**PSD Significant Emission Rate**[2] (tpy)	**Project Triggers PSD Review?** (Yes/No)
PM	-254	25	No
PM_{10}	-248	15	No
$PM_{2.5}$	-223	10	No
NO_X	-4,036	40	No
CO	-174	100	No
SO_2	-1,118	40	No
H_2SO_4	-0.2	7	No
Lead	-0.024	0.6	No
GHGs (as CO_2e)	-836,545	75,000 [3]	No

[1] Only those regulated NSR pollutants for which the project emissions increase could potentially exceed the SER are listed.

[2] Per 40 CFR §52.21(b)(40), which points to (b)(23), where significant means, in reference to an *emissions increase* of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates.
Note, O_3: 40 tpy of VOC emissions **or** 40 tpy of NO_X emissions
$PM_{2.5}$: 10 tpy of direct $PM_{2.5}$ emissions; 40 tpy of SO_2 emissions; **or** 40 tpy of NO_X emissions unless demonstrated not to be a $PM_{2.5}$ precursor under paragraph (b)(50).

[3] CO_2e (GHG Pollutants) only become subject to regulation and potentially applicable to PSD if another regulated NSR pollutant triggers PSD.

Table 4-2. NGCC Project Emissions Increases Compared with NA-NSR Major Modification Thresholds

Pollutant[1]	"Step 1" Project Emissions Increase (tpy)	NA-NSR Major Modification Threshold[2] (tpy)	Project Triggers NA-NSR Review? (Yes/No)
Ozone			No
NO_X	-4,036	40	
VOC	**11**	40	

[1] Jefferson County is nonattainment for the 8-hour Ozone NAAQS promulgated in 2015.

[2] Per Paragraph 1.27, which points to 1.10.1 of Regulation 2.04, where *significant* means, in reference to an *emissions increase* of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates, where
Ozone: 40 tpy of VOC emissions **or** 40 tpy of NO_X emissions

As shown in Tables 4-1 and 4-2, the proposed NGCC Project is not a major modification under either the PSD or NA-NSR permitting programs, and thus do not trigger permitting requirements of these programs.

In accordance with paragraph 7.6 of Regulation 2.04, projects that ***do not*** constitute a PSD major modification when calculated using the BAE to PAE methodology, but which have a "reasonable possibility" to result in a significant emissions increase, are subject to additional recordkeeping and reporting requirements including the requirement to calculate and maintain a record of annual emissions, in tons per year on a calendar year basis for at least 5 years following resumption of regular operations after the modification (or 10 years if the project increases the design capacity or potential to emit of a regulated NSR pollutant). Reasonable possibility is defined as either: 1) where the difference between BAE and PAE is greater than 50% of the significance level for the regulated pollutant; or 2) where the difference between BAE and PAE prior to subtraction of the emissions excluded from PAE through the could have accommodated exclusion is greater than 50% of the significance level for the regulated pollutant. For the proposed NGCC Project, the emissions increase of all pollutants except VOC are below zero. For VOC, while there is a calculated project emissions increase (11 tpy), the amount is well below 50% of the SER and therefore, the NGCC Project is not subject to the reasonable possibility recordkeeping and reporting requirements of Section 7 of Regulation 2.04.

5. APPLICABLE FEDERAL AND STATE REQUIREMENTS

Emission units constructed as part of the proposed NGCC Project will be subject to certain federal and APCD air quality regulations. This section of the application summarizes the air permitting requirements and the key air quality regulations that will apply to emission units constructed as part of the NGCC Project. Specifically, applicability to NSPS, pollutant- and category-specific NESHAP, Compliance Assurance Monitoring (CAM), Title V operating permit regulations, Acid Rain Program (ARP), Cross-State Air Pollution Rule (CSAPR), and APCD-specific regulations are addressed.

In Appendix C, Form AP-100H identifies regulatory requirements for the NGCC Project. As an optional supplement to the application, to assist in APCD's review of the application and development of a Construction Permit and revised Title V permit, an edited version of the existing Title V permit for Mill Creek Generating Station showing new and modified permit revisions that would encompass the proposed project is provided in Appendix D.

5.1 New Source Performance Standards

Section 111 of the CAA, Standards of Performance of New Stationary Sources, requires EPA to establish federal emissions standards for source categories that cause or contribute significantly to air pollution. EPA is required to establish standards based on the best systems of emission reductions from technologies that have been adequately demonstrated, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, EPA has promulgated more than 75 standards. The NSPS are codified in 40 CFR 60.

Any source subject to an NSPS is also subject to the general provisions of NSPS Subpart A, except as noted. A review of all NSPS that could potentially be applicable to any of the new emission units associated with the NGCC Project is presented in this section. The list of category-specific NSPS that will apply to the emission units for the NGCC Project are as follows:

- 40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units – Applies to the Auxiliary Boiler (U24/E50) and Fuel Gas (Dewpoint) Heater (U26/E52)
- 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines – Applies to Gas Turbine with HRSG (U23/E49)
- 40 CFR 60 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units – Applies to Gas Turbine with HRSG (U23/E49)
- 40 CFR 60 Subpart IIII – Stationary Compression Ignition Combustion Engines – Applies to the 2 MW Diesel Emergency Generator Engine (U25/E51) and the Emergency Diesel Driven Fire Pump Engine (IA4/IE28)

5.1.1 40 CFR 60 Subpart A – General Provisions (Applicable)

All affected sources subject to source-specific NSPS are subject to the general provisions of NSPS Subpart A unless specifically excluded by the source-specific NSPS. Subpart A requires initial notification, performance testing, recordkeeping and monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

5.1.2 NSPS Subpart D – Fossil Fuel-Fired Steam Generators > 250 MMBtu/hr (Not Applicable)

40 CFR 60 *Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators* (NSPS D), applies to fossil fuel-fired steam generating units with heat input capacities greater than 250 MMBtu/hr that have been constructed or modified since August 17, 1971.[29] The rule defines a fossil fuel-fired steam generating unit as:[30]

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

The GT and HRSG with NG-fired DBs (U23/E49) will not be subject to NSPS D because:

- The GT is not classified as a steam generating unit under this regulation and
- The HRSG with NG-fired DBs will be subject to NSPS Subpart KKKK instead and as such, are not subject to NSPS D.[31]

The Auxiliary Boiler (U24/E50) and Fuel Gas (Dewpoint) Heater (U26/E52) are each implicitly not subject since their heat input capacity is less than 250 MMBtu/hr.

5.1.3 NSPS Subpart Da – Electric Utility Steam Generating Units > 250 MMBtu/hr (Not Applicable)

40 CFR *Subpart Da – Standards of Performance for Electric Utility Steam Generating Units* (NSPS Da), provides standards of performance for electric utility steam generating units with heat input capacities greater than 250 MMBtu/hr of fossil fuel (alone or in combination with any other fuel) for which construction, modification, or reconstruction commenced after September 18, 1978.[32] The term "steam generating unit" is defined under this regulation as:[33]

> *For units constructed, reconstructed, or modified after May 3, 2011, steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines…*

The GT and HRSG with NG-fired DBs (U23/E49) will not be subject to NSPS Subpart Da because:

- The GT is not classified as a steam generating unit under this regulation and
- The HRSG with NG-fired DBs will be subject to NSPS Subpart KKKK instead and as such, are not subject to NSPS Subpart Da.[34]

The Auxiliary Boiler (U24/E50) and Fuel Gas (Dewpoint) Heater (U26/E52) are each implicitly not subject since their heat input capacity is less than 250 MMBtu/hr.

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[29] 40 CFR §60.40
[30] 40 CFR §60.41
[31] 40 CFR §60.40(e)
[32] 40 CFR §60.40Da(a)
[33] 40 CFR §60.41Da
[34] 40 CFR §60.40Da(e)

5.1.4 NSPS Subpart Db – Steam Generating Units > 100 MMBtu/hr (Not Applicable)

40 CFR 60 *Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units* (NSPS Db), provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.[35] The term "steam generating unit" is defined under this regulation as:[36]

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

The GT and HRSG with NG-fired DBs (U23/E49) will not be subject to NSPS Subpart Db, because:

- The GT is not classified as a steam generating unit under this regulation and
- HRSGs with NG-fired DBs will be subject to NSPS Subpart KKKK instead and as such, are not subject to NSPS Subpart Db.[37]

The Auxiliary Boiler (U24/E50) and Fuel Gas (Dewpoint) Heater (U26/E52) are each implicitly not subject to NSPS Db since their heat input capacity does not exceed 100 MMBtu/hr.

5.1.5 NSPS Subpart Dc – Small Steam Generating Units (Applicable)

40 CFR 60 *Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* (NSPS Dc), provides standards of performance for each steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989, and that the maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr.[38] The term "steam generating unit" is defined under this regulation as:[39]

> *Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term does not include process heaters as defined in this subpart.*

The GT and HRSG with NG-fired DBs (U23/E49) will not be subject to NSPS Subpart Dc because its heat capacity is well above the applicability threshold.

However, both the new NG-fired Auxiliary Boiler (U24/E50) and Fuel Gas (Dewpoint) Heater (U26/E52), meet the definition of a steam generating unit and fall within the applicable heat input capacity range, and

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[35] 40 CFR §60.40b(a)

[36] 40 CFR §60.41b

[37] 40 CFR §60.40b(i)

[38] 40 CFR §60.40c(a)

[39] 40 CFR §60.41c

each is an affected facility after the applicability date.[40] Units subject to NSPS Subpart Dc that fire natural gas do not have to meet any applicable emission limits, testing, or monitoring requirements under this subpart, except for the requirement to monitor natural gas consumption on a monthly basis. Initial notifications of the dates of construction commencement, anticipated startup, actual startup, in addition to the design heat input capacity and the identification of fuels to be combusted must be submitted to the APCD.

5.1.6 NSPS Subpart GG – Stationary Gas Turbines (Not Applicable)

40 CFR 60 *Subpart GG – Standards of Performance for Stationary Gas Turbines* (NSPS GG), applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, that are constructed, modified, or reconstructed after October 3, 1977.[41]

The GT and HRSG with NG-fired DBs (U23/E49) will be a stationary gas turbine with a heat input above the threshold and constructed after the applicability date. However, pursuant to 40 CFR §60.4305(b), stationary combustion turbines regulated under NSPS KKKK are exempt from the requirements of NSPS GG. Therefore, NSPS GG does not apply.

5.1.7 NSPS Subpart KKKK – Stationary Combustion Turbines (Applicable)

40 CFR 60 *Subpart KKKK – Standards of Performance for Stationary Combustion Turbines* (NSPS KKKK) establishes emissions limits for a combustion turbine (all references to GT are synonymous with a combustion turbine) and associated HRSG or DBs that commenced construction, modification, or reconstruction after February 18, 2005, and have a heat input from the GT at peak load equal to greater than 10.7 gigajoules (10 MMBtu/hr) based on the HHV of the fuel. HRSGs with DBs regulated under NSPS KKKK are exempt from the requirements of NSPS D, Da, Db, and Dc. Also, because the GT is subject to NSPS KKKK, it is exempt from NSPS GG.

The affected facility under NSPS KKKK is a stationary combustion turbine, which is defined by 40 CFR §60.4420 as:

> "*all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and subcomponents comprising any simple cycle stationary combustion turbine, any regenerative/ recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.*"

The GT and HRSG with NG-fired DBs (U23/E49) will be a combustion turbine with a heat input above the threshold and constructed after the applicability date and thus will be subject to NSPS KKKK. NSPS KKKK specifies emissions limitations, monitoring, reporting, and recordkeeping requirements for NO_X and SO_2.

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[40] The Fuel Gas (Dewpoint) Heater is equipped with a water/glycol bath (i.e., the heat transfer medium) that indirectly heats the pipeline gas stream, which makes it subject to NSPS Dc.

[41] 40 CFR §60.330

5.1.7.1 Emissions Limits

For a new GT firing natural gas with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 15 ppm at 15% O_2 or 0.43 lb/megawatt hour (MWh) gross energy output.[42] NSPS KKKK also includes, for units greater than 30 MW output, a NO_X limit of 96 ppm at 15% O_2 or 4.7 lb/MWh gross output for turbine operation at ambient temperatures less than 0°F and turbine operation at loads less than 75% of peak load.[43] Compliance with the NO_X emission limit is determined on a 30-unit operating day rolling average basis.[44]

SO_2 emissions into the atmosphere from GTs located in the continental U.S. are limited to 0.9 lb/MWh gross output (or 110 nanograms per Joule (ng/J)), **or** the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.[45]

As documented in detail in Section 5 of Appendix B, LG&E's GT/DB will have NO_X and SO_2 emissions well below the NSPS KKKK emissions standards and will comply with the applicable monitoring, reporting, and performance test requirements of NSPS KKKK.

5.1.7.2 Monitoring and Testing Requirements

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

5.1.7.2.1 NO_X Compliance Demonstration Requirements

The GT will not use either water or steam injection; therefore, the continuous compliance requirements at 40 CFR §60.4340 apply. Pursuant to 40 CFR §60.4340(b)(1), LG&E will install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) as described in 40 CFR §§ 60.4335(b) and 60.4345. LG&E will certify according to 40 CFR Part 75 Appendix A to demonstrate ongoing compliance with the NSPS KKKK NO_X emission limits. Sources demonstrating compliance with the NO_X emission limit via CEMS are not subject to the requirement to perform initial and annual NO_X stack tests.[46] Initial compliance with the NO_X emission limit will be demonstrated by comparing the arithmetic average of the NO_X emissions measurements taken during the initial relative accuracy test audit (RATA) required pursuant to 40 CFR §60.4405 to the NO_X emission limit under NSPS KKKK.[47]

5.1.7.2.2 SO_2 Compliance Demonstration Requirements

For compliance with the SO_2 emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by APCD;[48] however, LG&E elects

[42] 40 CFR §60.4320(a) and Table 1

[43] Ibid.

[44] 40 CFR §60.4350(h), 40 CFR §60.4380(b)(1)

[45] 40 CFR §60.4330(a)(1) or (a)(2), respectively

[46] 40 CFR 60.4340(a)

[47] 40 CFR 60.4405(c)

[48] 40 CFR 60.4370(b) and (c)

to opt out of this provision of the rule by using a fuel that is demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO_2.[49] This demonstration can be made using one of the following methods:

- By using a purchase contract specifying that the fuel sulfur content for the natural gas is less than or equal to 20 gr/Cscf of sulfur and results in potential emissions not exceeding 0.060 lb/MMBtu; or
- By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4 which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input.

As shown in the attached permit mark up, LG&E will accept the fuel sulfur limitation shown in 40 CFR §60.4330(a)(2) of 20 gr/Cscf of sulfur or less.

Pursuant to 40 CFR §60.4365(a), the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifies that the total sulfur content for natural gas used at Mill Creek Generating Station is less than 20 gr/Cscf.

5.1.8 NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (Applicable)

40 CFR 60 *Subpart IIII - Standards of Performance for Stationary Compressions Ignition Internal Combustion Engines* (NSPS IIII) applies to owners or operators of stationary compression ignition (CI) internal combustion engines (ICE) manufactured after April 1, 2006 that are not fire pump engines, and fire pump engines manufactured after July 1, 2006 that commence construction after July 11, 2005.

5.1.8.1 Emergency Fire Pump Engine (IA4/IE28)

The NGCC Project is provisioned to have a nominal 400 hp fire pump engine that will combust ULSD. The date of manufacture for the emergency fire pump engine and date of construction will occur after the dates specified above; therefore, the emergency fire pump engine will be subject to the provisions of NSPS IIII.

Since the proposed emergency fire pump engine will have a power rating of 400 hp and a displacement of less than 30 liters per cylinder, the emergency fire pump engine must comply with the emission standards in Table 4 of NSPS IIII for all pollutants [§60.4205(c)]. Specifically, the emergency fire pump engine must meet the following emissions standards for non-methane hydrocarbons (NMHC)+NO_X and PM:[50]

- 3.0 grams per horsepower-hour (g/hp-hr) of NMHC+NO_X, and
- 0.15 g/hp-hr of PM.

As documented in the emissions calculations provided in Appendix B, the proposed emergency fire pump engine will meet these emissions limits.

As provided in 40 CFR §60.4211(c), to demonstrate compliance with these emission standards, LG&E will purchase an emergency fire pump engine certified to the emission limits listed in Table 4 of NSPS IIII or more stringent, and will install and configure the engine according to the manufacturer's specifications. No performance testing is required.

[49] 40 CFR 60.4365

[50] NSPS IIII does not establish CO emission limits for fire pump engines manufactured after 2008 for engines at this size.

Effective October 1, 2010, only diesel fuel that meets the requirements set forth in 40 CFR §1090.305 may be used in accordance with 40 CFR §60.4207(b). This regulation states that the sulfur content must remain less than or equal to 15 ppm, and either the cetane index must be at least 40, or the aromatic content must be less than or equal to 35 volume percent.

Under NSPS IIII, LG&E will monitor emergency fire pump engine hours of operation using a non-resettable hour meter and records per §60.4214(b) will be maintained. No other monitoring is required.

Although the emergency fire pump engine is subject to NSPS IIII, based on its potential emissions, it qualifies to be designated as an insignificant activity. LG&E has therefore presumed that it will be included in the existing IA4 IA grouping and has been given a proposed Emission Point designation of IE28.

5.1.8.2 Emergency Generator Engine (U25/E51)

The NGCC Project is provisioned to have a 2 MW rated emergency generator engine and will be a 2021 model year or later unit. Since the diesel fired engine (2,682 hp) serving the generator will be used for emergency purposes and cylinder displacement is less than 10 liters/cylinder, the engine will be subject to the emission limits in 40 CFR §§60.4205(b) and 60.4202(a)(2) and the fuel specifications of 40 CFR §60.4207.

Per 40 CFR §60.4205(b),

> *(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.*

Per 40 CFR §60.4202(a)(2),

> *(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.*
>
>> *(2) For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007.*

Starting with Model Year 2006, a new engine with a rated power greater than or equal to 130 kW but less than or equal to 560 kW, must meet the Tier 3 standard in Table 3 to Appendix I as specified in 40 CFR Part 1039. As the emergency generator's rate power is greater than 560 kW, it must meet the Tier 2 standards in Table 2 to Appendix I.[51]

Table 2 to Appendix I - Tier 2 Emission Standards contain the following applicable emission limits:

- 6.4 grams per kilowatt hour (g/kW-hr) (equivalent to 4.8 g/hp-hr) of NMHC+ NO_X,

[51] https://www.ecfr.gov/current/title-40/part-1039#Appendix-I-to-Part-1039

- 3.5 g/kW-hr (equivalent to 2.6 g/hp-hr) of CO, and
- 0.20 g/kW-hr (equivalent to 0.1 g/hp-hr) of PM.

Pursuant to 40 CFR §1039.105(b)(1) through (3), smoke from the engine may not exceed the following standards.

1. 20 percent during acceleration mode;
2. 15 percent during lugging mode; and
3. 50 percent during peaks in either the acceleration or lugging mode.

As provided in 40 CFR §60.4211(c), to demonstrate compliance with these emission standards, LG&E will purchase an emergency generator certified to the emission limits listed 40 CFR §60.4205(b) or more stringent, and will install and configure the engines according to the manufacturer's specifications. No performance testing is required.

LG&E will use diesel fuel that meets the requirements of 40 CFR §1090.305 for nonroad diesel fuel in accordance with 40 CFR §60.4207(b). This regulation states that the sulfur content must remain less than or equal to 15 ppm, and either the cetane index must be at least 40, or the aromatic content must be less than or equal to 35 volume percent.

Under NSPS IIII, LG&E will monitor hours of operation of the emergency generators using non-resettable hour meters and records per 40 CFR §60.4214(b) will be maintained. No other monitoring is required.

5.1.9 NSPS Subpart TTTT – GHG Emissions for Electric Generating Units (Applicable)

40 CFR 60 *Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units* (NSPS TTTT) is applicable to any steam generating unit, integrated gasification combined-cycle, or stationary GT that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014, that:

- Has a base load rating greater than 250 MMBtu/hr of fossil fuel.
- Serves a generator(s) capable of selling greater than 25 MW of electricity to a utility power distribution system.

Given that the proposed GT and HRSG with NG-fired DBs (U23/E49) meets all three applicability criteria under 40 CFR §60.5509(a) and do not meet any of the exemption criteria under 40 CFR §60.5509(b), this emission unit will be subject to the provisions of NSPS TTTT.

Note that the NGCC Project is considered a base load natural gas-fired unit. By definition, such a unit must (1) combust more than 90 percent natural gas on a heat input basis on a 12-operating-month rolling average basis and (2) supply more than (i) its design efficiency or 50 percent, whichever is less, (ii) times its potential electric output as net-electric sales on both a 12-operating-month and a three-year rolling average basis.

The GT and DB will be subject to the following key requirements under NSPS TTTT:

- Per 40 CFR §60.5520(a), emissions of CO_2 must be limited to 1,000 lb/MWh of gross energy output and 1,030 lb/MWh of net energy output.

- Per 40 CFR §60.5520(d), as long as the GT is only permitted to burn uniform fuels that result in a consistent emission rate of 160 lb CO_2/MMBtu or less, it is not subject to any monitoring or reporting requirements under this subpart. LG&E is only required to maintain purchase records for permitted fuels.
- Per 40 CFR §60.5550, LG&E must submit a notification of the date of construction and actual date of initial startup of the NGCC Unit.

5.1.10 NSPS Subpart UUUUa – GHG Emissions from Existing Electric Utility Generating Units (Not Applicable)

40 CFR 60 *Subpart UUUUa – Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units* (NSPS UUUUa), is applicable to steam generating units that commence construction on or before January 8, 2014. NSPS UUUUa is not applicable to the NGCC Project because it will commence construction after the applicability date, in addition to being an EGU that is subject to NSPS TTTT, which is excluded from being a designated facility per 40 CFR §60.5780a(a)(1). Moreover, pursuant to 40 CFR §60.5780a(a)(3), a stationary combustion turbine that meets the definition of a simple cycle stationary combustion turbine, a combined cycle stationary combustion turbine, or a combined heat and power combustion turbine is excluded from being a designated facility as well.

5.2 National Emissions Standards for Hazardous Air Pollutants

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

Even after the shutdown of the Units 1 and 2 coal-fired boilers, the Mill Creek Generating Station will remain a major source for individual HAP and total HAPs.

Any source subject to a NESHAP is also subject to the general provisions of 40 CFR Subpart A, except as noted. A review of all NESHAP that could potentially be applicable to any of the new emission units associated with the NGCC Project is presented in this section. The list of NESHAP that will apply to the emission units for the NGCC Project are as follows:

- 40 CFR 63 Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters – Applies to Auxiliary Boiler (U24/E50) and Fuel Gas (Dewpoint) Heater (U26/E52)
- 40 CFR 63 Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines – Applies to 2 MW Diesel Emergency Generator Engine (U25/E51) and 400 hp Emergency Diesel Driven Fire Pump Engine (IA4/IE28)
- 40 CFR 63 Subpart YYYY – NESHAP for Combustion Turbines – Applies to Unit 12 GT/HRSG (U23/E49)

5.2.1 NESHAP Subpart DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Applicable)

40 CFR 63 *Subpart DDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* (Boiler MACT) applies to industrial, commercial, or

institutional boilers or process heaters, as defined in 40 CFR §63.7575 that are located at, or are part of, a major source of HAP, except as specified in 40 CFR §63.7491. Boiler MACT applies to each new, reconstructed, or existing affected source, where the affected source includes the collection of all existing industrial, commercial, and institutional boilers and process heaters within an applicable subcategory defined in 40 CFR §63.7575 and each new or reconstructed industrial, commercial, or institutional boiler or process heater.

The Auxiliary Boiler (U24/E50) that will be installed as part of the NGCC Project is an industrial boiler (99.9 MMBtu/hr) and will be located at a major HAP source. It will thus be subject to Boiler MACT. The Fuel Gas (Dewpoint) Heater (U26/E52), which is equipped with burners with a heat input capacity of 15 MMBtu/hr, is classified as a process heater and thus will also be subject to Boiler MACT. As these combustion units are designed to use natural gas as the sole fuel for combustion, they will be categorized as "units designed to burn gas 1 fuels" per 40 CFR §63.7499.

LG&E plans to provide multiple natural gas-fired HVAC units within buildings that are associated with the NGCC Project. The specific make and model will not be known until farther along in the project development phase. The total combined heat input capacity of all these small HVAC heaters can be presumed to be 10 MMBtu/hr or less and this maximum value has been used to define the total potential emissions of all the HVAC heaters. Any installation defined as a hot water heater will not be subject to Boiler MACT.[52] None of the small HVAC units are expected to be affected sources for Boiler MACT.

Pursuant to 40 CFR §63.7500(a), the Auxiliary Boiler (U24/E50) and Fuel Gas (Dewpoint) Heater (U26/E52) must comply with the emission limits and work practice standards presented in Tables 1 through 3 of the Boiler MACT and the operating limitations found in Table 4. Table 1 specifies emissions limitations for new boilers, but this table only includes emissions limitations for units designed to burn solid, liquid, and gaseous fuels defined under the "gas 2" fuel category. As the two new applicable units are considered "units designed to burn gas 1 fuels", they are not subject to any emissions standards. However, these units are subject to a limited number of work practice standards detailed in Table 3 of the Boiler MACT. These include the requirement to conduct periodic tune-ups where the frequency of the tune-up is dependent on the heat input capacity of the boiler and the presence of a continuous oxygen trim system that maintains an optimum air-to-fuel ratio.

- Per 40 CFR §63.7500, LG&E must conduct a tune-up of the Auxiliary Boiler and Fuel Gas (Dewpoint) Heater annually as specified in 40 CFR §63.7540(a)(10), unless the unit has a continuous oxygen trim system that maintains an optimum air to fuel ratio. The first tune-up must be no later than 13 months after the initial startup of each boiler, per 40 CFR §63.7515(d).
- Per 40 CFR §63.7530(f), LG&E must submit a notification of compliance status containing the results of the initial compliance demonstration according to the requirements in 40 CFR §63.7545(e).
- Per 40 CFR §63.7540(b), LG&E must report any instances it did not meet the tune-up requirements and reported according to the requirements of 40 CFR §63.7550.
- Per 40 CFR §63.7545, LG&E must submit an initial notification no later than 15 days after the actual date of startup.
- Per 40 CFR §63.7550, LG&E must submit a compliance report annually.

[52] Hot water heater means, a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

- Per 40 CFR §63.7555, LG&E must keep records of each notification and report submitted for 5 years following the date of each occurrence.

LG&E has documented the relevant Boiler MACT provisions on Form AP-100H in Appendix C.

5.2.2 NESHAP Subpart ZZZZ – Reciprocating Internal Combustion Engines (Applicable)

40 CFR 63 *Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines* (RICE MACT) regulates HAPs emitted from stationary reciprocating internal combustion engines (RICE) located at major and area source of HAP emissions. The NGCC Project includes two stationary RICE: 1) 2 MW Diesel Emergency Generator (U25/E51) and 2) 400 hp Diesel Driven Fire Pump (IA4/EI28).

Pursuant to 40 CFR §63.6590(c)(6), a new emergency use stationary RICE with a site rating of less than or equal to 500 brake horsepower located at a major source of HAPs (e.g., 400 hp Emergency Diesel Driven Fire Pump engine), must meet the requirements of RICE MACT by meeting the requirements of NSPS IIII for compression ignition engines. No further requirements apply for such engines under this part. Therefore, the emergency use 400 hp Diesel Driven Fire Pump engine will demonstrate compliance with RICE MACT by demonstrating compliance with NSPS IIII.

For the 2 MW Diesel Emergency Generator Engine, pursuant to 40 CFR §63.6590(b)(1) and (b)(1)(i), LG&E does not have to meet the requirements of RICE MACT and of 40 CFR 63, Subpart A except for the initial notification requirements of 40 CFR §63.6645(f).

5.2.3 NESHAP Subpart YYYY – Stationary Combustion Turbines (Applicable)

40 CFR 63 *Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* (NESHAP YYYY) establishes emissions and operating limitations for HAP from existing, reconstructed, or new stationary combustion turbines (herein referenced as the GT), located at major stationary sources of HAP. The Mill Creek Generating Station will continue to be classified as a major stationary source of HAP after the NGCC Project. The proposed GT and HRSG with NG-fired DBs (U23/E49) meets the definition of an affected source under NESHAP YYYY and therefore will be subject to this regulation.[53] Note that the DBs and waste heat recovery units (even if part of a GT) are explicitly identified as not subject to this rule because they are considered steam generating units and, potentially, subject to other Part 63 standards.

NESHAP YYYY requirements for GT are dependent on the type of combustion system used- lean premix or diffusion combustion system. A lean premix combustion system operates with a lower flame temperature compared to a diffusion combustion system, resulting in lower NO_X emissions. Each of the prospective vendors LG&E is currently evaluating that will provide the GT will use the DLN combustor technology. As a result, and the proposed GT is considered a lean premix natural gas-fired stationary combustion turbine as defined in 40 CFR §63.6175.

The GT will be subject to the following key requirements under NESHAP Subpart YYYY. All applicable provisions under NESHAP YYYY are documented on Form AP-100H in Appendix C.

[53] There was a stay for NESHAP Subpart YYYY in 2004 on all requirements, except for an initial notification; however, this stay was lifted on March 9, 2022. https://www.federalregister.gov/documents/2022/03/09/2022-04848/national-emission-standards-for-hazardous-air-pollutants-stationary-combustion-turbines-amendments

- Per 40 CFR §§63.6095 and 63.6145, LG&E must submit an initial notification not later than 120 days after becoming subject to this subpart.
- Per 40 CFR §63.6100 and Table 1 of NESHAP YYYY, LG&E must limit the concentration of formaldehyde to 91 ppbvd or less at 15% O_2, except during turbine startup.
- Per 40 CFR §63.6110, LG&E must conduct an initial performance test within 180 days after startup of the turbines for formaldehyde.
- Per 40 CFR §63.6115, LG&E must conduct annual performance tests.
- Per 40 CFR §63.6125, LG&E must monitor on a continuous basis the oxidation catalyst inlet temperature.
- Per 40 CFR §63.6135, LG&E must conduct all parametric monitoring at all times the GT is operating, except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities.
- Per 40 CFR §63.6145, LG&E must submit an initial notification no later than 120 days after startup, a notification of intent prior to conducting the initial performance test, and a notification of compliance status for the formaldehyde emission limit.
- Per 40 CFR §63.6150, LG&E must submit a semiannual compliance report according to Table 6 of the subpart.
- Per 40 CFR §63.6155, LG&E must keep a copy of each notification, performance test, records of startup events, and records of deviations for 5 years, per 63.6160.

5.2.4 NESHAP Subpart UUUUU – Coal & Oil-Fired Electric Utility Steam Generating Units (Not Applicable)

40 CFR 63 *Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* is referenced to in short as the Mercury and Air Toxics Standards (MATS) and, applies to electric utility steam generating units (EGUs) that combust coal or oil.[54] Pursuant to 40 CFR 63.9983(a), any unit designated as a major source stationary combustion turbine subject to NESHAP YYYY is not subject to MATS. Moreover, the proposed GT and HRSG with NG-fired DBs (U23/E49) does not have the capability of firing oil. As such, it is not an affected source for MATS and will not be subject to the MATS rule.

5.3 Compliance Assurance Monitoring (40 CFR 64)

The Compliance Assurance Monitoring (CAM) regulations apply to pollutant-specific emission units at a major source under the Title V operating permit program that satisfy the following criteria as detailed in 40 CFR §64.2(a):

- The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under §64.2(b);
- The unit uses a control device to achieve compliance with any such limitation or standard; and
- The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source.

Title V permit applicants must prepare and submit a CAM Plan for subject units as part of Title V permit applications. The CAM Plans are intended to document the methods that will be followed to provide an on-going and reasonable assurance of compliance with emission limits. For a subject unit using a control device whose post-controlled emissions exceed the major source threshold (referred to as large pollutant-specific

[54] 40 CFR 63.9980

emission units [PSEU] in the rule), a CAM plan is required to be submitted with the initial Title V air operation permit application. For a subject unit whose post-control emissions are less than the major source threshold, a CAM plan does not have to be submitted until the first Title V air operation permit renewal application.

The proposed GT and HRSG with NG-fired DBs (U23/E49) will potentially be subject to CAM requirements as it operates a control train system for NO_X, CO, and formaldehyde. NO_X is limited to 15 ppmvd at 15% O_2 pursuant to 40 CFR §60.4320 & Table 1 of NSPS KKKK. To meet these limits, LG&E is requiring each prospective combustion turbine vendor to guarantee a maximum NO_X emission rate of no more than 2 ppmvd at 15% O_2. The pre-controlled and post-controlled potential to emit will be above 100 tpy. LG&E will install, operate, and maintain a NO_X CEMS to ensure continuous compliance. The unit meets the second two CAM applicability criteria; however, since the applicable NO_X emissions standard is from NSPS KKKK, a CAA Section 112 standard that was promulgated after November 15, 1990, the emission limit is exempt from CAM pursuant to 40 CFR §64.2(b)(1)(i). Therefore, NO_X from the GT and DB are not subject to CAM requirements.

The GT and HRSG with NG-fired DBs is not subject to an emission limitation or standard for CO (or a surrogate thereof) under any applicable regulation, nor is any synthetic limit on CO emissions expected or warranted as part of the NGCC Project permit action; therefore, CAM does not apply for CO.

Formaldehyde from the GT and HRSG with NG-fired DBs is limited to 91 ppmvd at 15% O_2 pursuant to 40 CFR §63.6100 and Table 1, Item 1, of NESHAP YYYY. LG&E is requiring each vendor to meet the same emissions limit as NESHAP YYYY. Although the post-controlled value will be lower than 10 tpy, the pre-controlled emissions are estimated to be above 10 tpy. Therefore, the unit meets the second two CAM applicability criteria. However, since the applicable formaldehyde emissions standard is from NESHAP YYYY, a CAA Section 112 standard that was promulgated after November 15, 1990, the emission limit is exempt from CAM pursuant to 40 CFR §64.2(b)(1)(i). Therefore, formaldehyde emissions from the GT are not subject to CAM requirements.

The proposed new Mechanical Draft Cooling Tower (IA5/IE24) will be equipped with inherent drift eliminators, which are not considered a control device. Further, regardless of this designation, the drift eliminators are not needed to meet any applicable PM emission standard and thus CAM is not applicable.

None of the other emission units associated with the NGCC Project are equipped with a control device and thus are implicitly not subject to CAM.

5.4 Risk Management Plans (40 CFR 68)

Subpart B of 40 CFR 68 (RMP Rule) outlines requirements for risk management prevention plans pursuant to Section 112(r) of the CAA. Applicability of the subpart is determined based on the type and quantity of chemicals stored at a facility. Mill Creek Generating Station stores anhydrous ammonia at levels that exceed the threshold quantity of 10,000 pounds and thus the RMP Rule currently applies. Anhydrous ammonia is currently supplied to the SCR for Units 3 and 4.

The facility is and will also continue to be subject to the General Duty Clause under the CAA Section 112(r)(1), which states:

> *The owners and operators of stationary sources producing, processing, handling or storing such substances [i.e., a chemical in 40 CFR part 68 or any other extremely hazardous substance] have a*

general duty [in the same manner and to the same extent as the general duty clause in the Occupational Safety and Health Act (OSHA)] to identify hazards which may result from (such) releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.

The NGCC Project will use aqueous ammonia at a concentration of no more than 19%, which is not regulated under the RMP program. Thus, the installation of the NGCC Project will not affect the plant's current regulated status under the RMP Rule.

5.5 Stratospheric Ozone Protection Regulations (40 CFR 82)

The requirements originating from Title VI of the CAA, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A, B, and F of 40 CFR 82 are potentially applicable to the facility. In particular, 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility operates, maintains, repairs, services, or disposes of appliances that utilize Class I, Class II, or non-exempt substitute refrigerants.[55] Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. It is expected that all repairs, service, and disposal of ozone depleting substances from such equipment (air conditioners, refrigerators, etc.) at the facility will be completed by a certified technician. LG&E will continue to comply with 40 CFR 82 Subpart F. The applicable provisions under 40 CFR 82 are already contained in the plant's existing Title V permit and the NGCC Project will not necessitate a change to these provisions.

5.6 Interstate Trading Programs

Starting with the Acid Rain Program mandated by the 1990 Clean Air Act Amendments, EPA has developed several market-based "cap and trade" regulatory programs. All market-based regulatory programs are overseen by EPA's Clean Air Markets Division (CAMD) and are referred to as CAMD regulations. The programs that are potentially applicable to LG&E are:

- Acid Rain Program (ARP) (1990 – ongoing)
- Clean Air Interstate Rule (CAIR) (2009 – 2014)
- Cross-State Air Pollution Rule (CSAPR) (2015 – ongoing)

5.6.1 Acid Rain Applicability

To reduce acid rain in the United States and Canada, Title IV (40 CFR 72 *et seq.*) of the CAA Amendments of 1990 established the ARP to substantially reduce SO_2 and NO_X emissions from electric utility plants. APCD incorporates the ARP by reference per Regulation 6.47*.* Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I and Phase II of the program. Upon Phase III implementation, the ARP in general applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale. The proposed combustion turbine will be a utility unit subject to the ARP. The facility is subject to the requirements of 40 CFR 72 (permits), 40 CFR 73 (SO_2), and 40 CFR 75 (monitoring) but the turbine will not be subject to the NO_X provisions (40 CFR 76) of the ARP regulations because the proposed turbine does not have the capability to burn coal. LG&E is required to apply for the required ARP permit at least two years prior to commencing operation of the proposed turbine.[56] Under 40 CFR 75 of the ARP,

[55] 40 CFR 82.150

[56] 40 CFR 72.30(b)(2)(ii); Regulation 6.47

LG&E is required to operate various CEMS for their coal-fired assets.[57] Further, the ARP requires the facility to possess SO_2 allowances for each ton of SO_2 emitted. The ARP also requires initial certification of the monitors within 90 days of commencement of commercial operation, quarterly reports, and an annual compliance certification.

5.6.2 Clean Air Interstate Rule/Cross-State Air Pollution Rule

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

A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement CAA requirements concerning the transport of air pollution across state boundaries. On July 6, 2011, the U.S. EPA finalized the Cross-State Air Pollution Rule (CSAPR). On December 30, 2011, CSAPR was stayed prior to implementation. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing an August 21, 2012, D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the D.C. Circuit, EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted EPA's request. CSAPR Phase I implementation is now in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule. Therefore, the CAIR section of the permit is irrelevant now that CSAPR has replaced CAIR. Upon reviewing the existing Title V permit for Mill Creek Generating Station, APCD already removed all CAIR requirements.

Units 1 through 4 are subject to the requirements for the CSAPR NOx Annual Trading Program, CSAPR NOx Ozone Season Trading Program, and CSAPR SO_2 Trading Program.

The current permit was issued after the 2016 CSAPR update that established CSAPR NO_X Ozone Season Group 2 Trading Program requirements in 40 CFR 97 Subpart EEEEE for a subset of CSAPR-affected states (including Kentucky). These requirements were incorporated into the Kentucky SIP in 401 KAR 51:250. Furthermore, US EPA finalized the Revised CSAPR Update on March 15, 2021, which is intended to resolve outstanding interstate pollution transport obligations for 21 states (including Kentucky) for the 2008 ozone NAAQS. The Revised CSAPR Update establishes CSAPR NO_X Ozone Season Group 3 Trading Program requirements in 40 CFR 97 Subpart GGGGG. Thus, the CSAPR NO_X Ozone Season Group 3 Trading Program requirements in 40 CFR 97 Subpart GGGGG are the current requirements regulating ozone season NO_X emissions at the Mill Creek Generating Station.

CSAPR applicability is similar but distinct from ARP, with applicability criteria and definitions per 40 CFR §97.402.[58] The CSAPR NO_X Ozone Season Group 3 Trading Program regulates stationary, fossil-fuel-fired boilers and *stationery, fossil-fuel-fired combustion turbines* serving, at any time, on or after January 1, 2005, a generator with a nameplate capacity exceeding 25 MWe and producing power for sale.[59]

[57] While not subject to ARP NO_X provisions per Part 76, Part 75 monitoring requirements for NO_X apply as referenced by CSAPR.

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

[59] 40 CFR §97.1004(a)(1) Applicability

LG&E's proposed combustion turbine will be an affected source under this regulation, and must comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR §§ 97.1030 through 97.1035. LG&E is required to monitor emissions of SO_2, NO_X, and maintain sufficient allowances under CSAPR for its operations. Monitoring requirements for NO_X mass emissions and individual unit heat input, including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, typically tie back to ARP requirements per 40 CFR Part 75.[60]

Regarding SO_2 emissions, Unit 5 GT/HRSG (U23/E49) will qualify as a fossil-fuel-fired *combustion turbine* as defined in 40 CFR §97.602 of the CSAPR SO_2 Group 1 Trading Program. As a CSAPR SO_2 Group 1 unit, LG&E is required to comply with the monitoring, recordkeeping, and reporting requirements 40 CFR 97 Subpart CCCCC and Subparts F and G of Part 75.[61] Pursuant to 40 CFR §75.11(d), LG&E can measure and record SO_2 emissions by one of three methods other than a SO_2 CEMS, which is the current method for the existing coal-fired boilers. LG&E is selecting the method shown in 40 CFR §75.11(d)(2) for the combustion turbine, where LG&E will provide other information satisfactory to the Administrator using the applicable procedures specified in Appendix D to 40 CFR Part 75. This appendix includes methods for default SO_2 emission rates (0.0006 lb/MMBtu), fuel flowmeters, gross calorific values, and calculated heat inputs to avoid the installation of SO_2 CEMS and flue gas flowrate monitoring.

To accommodate the NGCC Project, the Title V permit will need to be modified to include the following information in Table 5-1. These changes are reflected in the suggested permit provided in Appendix D.

Table 5-1. Edits to Attachment F Section I of Mill Creek Generating Station's Title V Permit

Unit ID: Unit 5, non-peaking natural gas-fired combustion turbine with natural gas-fired duct burners					
Parameter	CEMS requirements pursuant to 40 CFR part 75, Subpart B (for SO_2 monitoring) and 40 CFR part 75, Subpart H (for NOx monitoring)	Excepted monitoring system requirements for gas- and oil- fired units pursuant to 40 CFR part 75, Appendix D	Excepted monitoring system requirements for gas- and oil- fired peaking units pursuant to 40 CFR part 75, Appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, Subpart E
SO_2		X			
NO_X	X				
Heat Input		X			

[60] 40 CFR §97.1029(a)(1) Requirements for installation, certification, and data accounting

[61] 40 CFR §97.630 General monitoring, recordkeeping, and reporting requirements

5.7 APCD Air Regulations

In addition to federal air regulations, APCD establishes regulations applicable at the emission unit level (source specific) and at the facility level for stationary sources. The rules also contain requirements related to the need for construction and/or operating permits. The following sections discuss the APCD regulations of relevance for the NGCC Project permit action.

5.7.1 APCD Part 1 – General Provisions

5.7.1.1 Regulation 1.01 – General Provisions

This regulation describes the general application of District regulations and emission standards. LG&E will abide by all appropriate regulations and emission standards as determined by the APCD.

5.7.2 APCD Part 2 – Permit Requirements

5.7.2.1 Regulation 2.03 – Authorization to Construct or Operate

Apart from the exemptions established by Regulation 2.02, changes made pursuant to Section 5.8 of Regulation 2.16 (i.e., "Operational Flexibility"), and projects limited to the construction or reconstruction of air pollution control equipment, a facility must obtain a permit to authorize construction of an affected facility in accordance with Regulation 2.03. Applications for permits to construct must contain the elements identified by Section 4 of Regulation 2.03 and must be made on forms authorized by the APCD. This application report and its appendices, which include the required forms, constitutes the construction permit application required by Regulation 2.03 as well as the operating permit revision application required under Regulation 2.16 for the Mill Creek Generating Station.

5.7.2.2 Regulation 2.04 – Construction or Modification of Major Sources In or Impacting Upon Non-Attainment Areas (Emission Offset Requirements)

Regulation 2.04 is addressed in Section 4 of this application report.

5.7.2.3 Regulation 2.05 – Prevention of Significant Deterioration of Air Quality

Regulation 2.05 is addressed in Section 4 of this application report.

5.7.2.4 Regulation 2.16 – Title V Permits

Mill Creek Generating Station is a major Title V source and will continue to be a major source following completion of the proposed project. LG&E requests that the terms and conditions of the construction permit resulting from this application be incorporated into the facility's Title V operating permit as a permit revision. Furthermore, following the completion of the project (including the decommissioning of the existing facility boilers), LG&E requests the terms and conditions associated with the operation of Units 1 and 2 (and supporting equipment) be removed from the facility's Title V operating permit in conjunction with commercial operation of the NGCC Unit. LG&E will notify the APCD when the existing operations associated with the NGCC Project are taken out of service.

5.7.3 APCD Part 5 – Standards for Toxic Air Contaminants and Hazardous Air Pollutants

5.7.3.1 Regulation 5.01 – General Provisions

This regulation applies to the owner or operator of any process equipment that emits or may emit a toxic air contaminant or hazardous air pollutant or for which a toxic air contaminant or hazardous air pollutant emission standard or other requirement is prescribed in a Part 5 regulation. A new or modified process or process equipment shall comply with all applicable emission standards upon commencing operation. LG&E will comply with all appropriate Part 5 regulations upon commencing startup of the new NGCC Unit operations.

5.7.3.2 Regulation 5.02 – Adoption of NESHAP

This regulation adopts particular NESHAP regulations that are listed in 40 CFR Parts 61 and 63. LG&E will comply with this District regulation by meeting the requirements of all NESHAP regulations that were discussed in Section 5.2 of this application.

5.7.3.3 Regulation 5.21 – Environmental Acceptability of Toxic Air Contaminants

The purpose of this regulation is to establish the criteria for determining the environmental acceptability of emissions of toxic air contaminants. This regulation sets the appropriate levels of risk that can be associated with toxic air contaminants at a new or modified process/facility. The APCD has developed the Strategic Toxic Air Reduction (STAR) Program to help reduce the levels of harmful contaminants in ambient air. LG&E has performed a full-scale STAR dispersion modeling analysis in order to demonstrate compliance with Regulation 5.21 and the STAR program. The analysis is presented in Section 5.8 of this application.

5.7.4 APCD Part 6 – Standards of Performance for Existing Affected Facilities

Per Regulation 6.01, Section 1 Applicability, unless specifically exempted in Regulation 2.03, Regulation 6 applies to any affected facility not permitted under Regulation 7, Standards of Performance for New Affected Facilities. Moreover, all affected facilities under this regulation must have permits issued pursuant to Regulation 2.

5.7.4.1 Regulation 6.42 - Reasonably Available Control Technology Requirements for Major VOC- and NOx-Emitting Facilities

This regulation establishes the requirements for Reasonably Available Control Technology (RACT) determination, demonstration, and compliance for VOC and NO_X emitting facilities for new or renewed operating permits.

Pursuant to Section 1.2, NO_X emissions from all NO_X -emitting facilities located at all major NO_X-emitting sources except for those NO_X-emitting facilities that have been or would be subject to NO_X review pursuant to 40 CFR Section 52.21 and Regulation 2.05 PSD after November 15, 1990, or to review under 40 CFR Part 51 Appendix S and Regulation 2.04 NA-NSR Review after November 15, 1992. As shown above in Section 4 of this application, the Mill Creek Generating Station is a major NO_X-emitting facility and the NGCC Project is not subject to full PSD or NA-NSR review.

Pursuant to Section 1.3.2, facilities that are used for emergency purposes only are exempt from the requirements to establish RACT requirements. Thus, a RACT determination for the emergency generator engine, fire pump engine, and their dedicated diesel fuel tanks is not required.

Pursuant to Section 4.3.1, each applicant for a *revised* operating permit shall be required to propose RACT emission-limiting standards and RACT emission control technology to be imposed by the revised operating permit, taking into account the recommendations set forth in any applicable Control Techniques Guidelines (CTG), Alternative Control Techniques (ACT) Document, or other EPA guidance for the facility. The operating permit application shall include a schedule for implementing the recommended RACT measures as expeditiously as practicable.

5.7.4.1.1 Proposed NO_X RACT for Unit 5 GT/HRSG

As described in Section 5.1.7 of this application, LG&E is requiring each vendor to meet a NO_X limit of 15 ppm at 15% O_2 to ensure continuous compliance with NSPS KKKK. This limit is proposed to be the RACT emission-limiting standard and represents the emission level that satisfies RACT requirements. Moreover, as documented in Section 2.3.1.1, all vendors being considered will utilize dry-low-NO_X combustors in the GT and LNBs in the HRSG. LG&E will install and operate oxidation catalysts and SCR as add-on controls to reduce stack NO_X, CO, HC, and organic HAP emissions. Operation of an SCR to ensure compliance with the proposed NO_X RACT limit, is a reasonable and available control technology for this type of base-load NGCC Unit that is subject to NSPS KKKK.

As represented throughout this application, LG&E is committed to meeting the NO_X RACT limit by installing and operating an SCR upon startup of commercial operation at the Mill Creek Generating Station. LG&E will demonstrate continuous compliance with this limit on a 30-unit operating day rolling average basis using data collected by the NO_X CEMS, as discussed in Section 5.1.7.

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

Initial compliance with the NO_X emission limit will be demonstrated by comparing the arithmetic average of the NO_X emissions measurements taken during the initial RATA required pursuant to 40 CFR §60.4405 to the NO_X emission limit under NSPS KKKK.

No further requirements are necessary outside of NSPS KKKK to be added to the revised permit to amend the NO_X RACT Plan. Please see similar references to NSPS KKKK that were added to Cane Run's Title V Permit No. O-0126-20-V, effective May 5, 2020, for U15 (Natural Gas-fired Combined Cycle Unit [EGU7]).

5.7.4.1.2 Proposed NO_X RACT Auxiliary Boiler and Fuel Gas (Dewpoint) Heater

As described in Section 2.3.2 above and in Section 6.3 of Appendix B, LG&E is requiring the vendor of the new 99.9 MMBtu/hr Auxiliary Boiler to equip the unit with LNBs and FGR to meet a 30 ppmv at 3% O_2 NO_X limit. The same specification requirement is being applied for the new Fuel Gas (Dewpoint) Heater. This translates into an NO_X emissions factor of 38.56 lb/MMscf or 0.0364 lb/MMBtu.

In March 1994, EPA published "Alternative Control Techniques Document – NO_X Emissions from Industrial/Commercial/Institutional (ICI) Boilers" (EPA-453/R-94-022).[62] Table 6-7 of this document summarizes EPA's NO_X control cost effectiveness determinations for natural gas-fired boilers, including various control technology options for a slightly larger-sized gas-fired packaged watertube boiler. Each

[62] https://www3.epa.gov/airquality/ctg_act/199403_nox_epa453_r-94-022_ici_boilers.pdf

option is presented with its corresponding controlled NO_X level: water injection and oxygen trim (0.06 lb/MMBtu for 150 MMBtu/hr unit; 0.08 lb/MMBtu for 250 MMBtu/hr unit), low NO_X burners (0.09 lb/MMBtu for 150 MMBtu/hr unit; 0.12 lb/MMBtu for 250 MMBtu/hr unit), low NO_X burners and FGR (0.07 lb/MMBtu for 150 MMBtu/hr unit; 0.10 lb/MMBtu for 250 MMBtu/hr unit), and SCR (0.03 lb/MMBtu for 150 MMBtu/hr unit; 0.04 lb/MMBtu for 250 MMBtu/hr unit). With the exception of the SCR-controlled unit rated at 150 MMBtu/hr, LG&E's proposed vendor specification for the new boilers – a NO_X exhaust concentration of 30 ppmv @ 3% O_2 (0.04 lb/MMBtu) – meets the performance of the best-controlled 150 MMBtu/hr and 250 MMBtu/hr gas-fired packaged watertube boiler represented by Table 6-7 of EPA's ACT document.

According to a separate EPA document published on July 30, 1993 and entitled "Fuel Switching to Meet the Reasonably Available Control Technology Requirements for Nitrogen Oxides", typical NO_X controls associated with RACT determinations "have involved modifications to combustion equipment, such as installation of low NO_X burners." Moreover, the EPA policy established by the 1993 document "allows States to adopt rules that permit utilities to control NO_X emissions by switching to cleaner fuels during the summertime ozone season." Even though LG&E's Mill Creek Generating Station is regulated as a utility, the proposed Auxiliary Boiler and Fuel Gas (Dewpoint) Heater are not affected units under the CSAPR NO_X Annual Trading Program or CSAPR NO_X Ozone Season Trading Program. Even so, these boilers will be equipped with LNBs/FGRs, which will reduce NO_X as an ozone precursor over the entire year, and especially during the ozone season.

To satisfy RACT requirements for NO_X emissions under Regulation 6.42, LG&E proposes a limit of 0.04 lb/MMBtu for the Auxiliary Boiler and Fuel Gas (Dewpoint) Heater. Compliance with this limit will be achieved by using natural gas, implementing LNBs and potentially FGR systems, and following manufacturer's recommended procedures regarding the operation and maintenance of each unit. LG&E will demonstrate compliance with this limit by tracking the fuel usage on a monthly basis.

Please see similar requirements that were added to Cane Run's Title V Permit No. O-0126-20-V, effective May 5, 2020, for U16 (Natural Gas-fired Auxiliary Boiler) and U17 (fuel gas dew point heater).

5.7.4.1.3 Proposed VOC RACT for Unit 5 GT/HRSG

As described in Section 3.1.1.1 of this application, LG&E is requiring each vendor to meet a VOC limit of 1 to 2 ppm at 15% O_2. Moreover, as described in Section 5.2.3 of this application, pursuant to 40 CFR §63.6100 and Table 1 of NESHAP YYYY, LG&E must limit the concentration of formaldehyde, which is a VOC, to 91 ppbvd or less at 15% O_2, except during turbine startup.

To ensure continuous compliance with NESHAP YYYY and LG&E's vendor requirement, the NGCC Unit proposed for this site includes an oxidation catalyst system as an add-on control device. NSPS KKKK requires an annual performance test for formaldehyde and continuous monitoring of the oxidation catalyst inlet temperature.

Upon reviewing the available SIP Board Orders published on APCD's website, the most recent proposed VOC RACT, as applicable for a combustion system, required the implementation of good combustion and operating practices to include design considerations, such as, 1) Selection of efficient burners; 2) Implementation of combustion controls to optimize efficiency; and 3) Use of insulation media to minimize heat losses.[63] That particular Board Order called, *American Synthetic Rubber Company / NOx RACT,*

[63] https://louisvilleky.gov/air-pollution-control-district/document/20211117-amended-agreed-board-order-asrc-ract-am2

Amendment 2, dated November 17, 2021, also includes references to tune-up requirements of 40 CFR §63.7540(a)(10) on an annual basis and includes a list of annual preventative maintenance steps.

LG&E is requesting that APCD consider including a similar VOC RACT requirement to implement good combustion and operating practices, as well as a reference to operating limitations, monitoring, and recordkeeping already contained within the NESHAP YYYY.

5.7.4.1.4 Proposed VOC RACT Auxiliary Boiler and Fuel Gas (Dewpoint) Heater

LG&E did not specify any requirement for limiting the VOC emissions from the Auxiliary Boiler or Fuel Gas (Dewpoint) Heater beyond the level specified in published AP-42 emissions factors.

LG&E requests that APCD consider the same applicable VOC RACT (good combustion and operating practices) from the SIP Board Order called, *American Synthetic Rubber Company / NOx RACT, Amendment 2*, dated November 17, 2021, be applied to the Auxiliary Boiler or Fuel Gas (Dewpoint) Heater.

5.7.5 APCD Part 7 – Standards of Performance for New Affected Facilities

5.7.5.1 Regulation 7.01 – General Provisions

This regulation establishes general requirements for any affected facility the construction, modification, or reconstruction of which is commenced on or after the effective date of an applicable standard of performance in Regulation 7. The NGCC Project will be comprised of newly constructed equipment. As such, this equipment will meet all applicable requirements set forth in Regulation 7.

5.7.5.2 Regulation 7.02 – Adoption of Federal NSPS

This regulation adopts particular NSPS regulations that are listed in 40 CFR Part 60. LG&E will comply with this District regulation by meeting the requirements of all NSPS regulations that were discussed in Section 5.1 of this application.

5.7.5.3 Regulation 7.06 – New Indirect Heat Exchangers

This regulation establishes requirements for new indirect heat exchangers. Both the auxiliary boiler and the fuel gas (dewpoint) heater will be subject to the requirements of this regulation.

Regulation 7.06 applies to indirect heat exchangers, meaning equipment used for the combustion of fuel in which energy is transferred through a medium that does not contact the products of combustion, with individual heat input capacities of more than 1 MMBtu/hr that are constructed, modified or reconstructed after August 17, 1971. LG&E's proposed Auxiliary Boiler and Fuel Gas (Dewpoint) Heater meet each of these criteria; therefore, PM and SO_2 emission standards established by Sections 4 and 5 of Regulation 7.06, respectively, will apply to the new units.

Section 4 of Regulation 7.06 establishes opacity standards and heat input-based PM emission limits. The applicable PM emission limit is determined based on the total heat input capacity for all the affected facilities at the source at the time of construction of the new units. A different heat input-based PM allowable emission rate applies depending on whether the total heat input capacity for the facility is less than 10 MMBtu/hr, between 10 MMBtu/hr and 250 MMBtu/hr, or above 250 MMBtu/hr. For sources with a total heat input capacity greater than 250 MMBtu/hr such as the Mill Creek Generating Station, Section 4.1.2 of Regulation 7.06 establishes a PM emissions limit of 0.10 lb/MMBtu actual heat input.

Section 4.2 establishes a 20% opacity limit with certain exceptions. The proposed Auxiliary Boiler and Fuel Gas (Dewpoint) Heater will be subject to these limits. The potential PM emission factor from combusting natural gas in the new heat exchangers is orders of magnitude lower than the allowable PM emission rate, so LG&E will be implicitly in compliance with these emission limits when burning natural gas.

Section 5 of Regulation 7.06 establishes SO_2 emissions standards. Specifically, for the combustion of gaseous fuels in sources with a total heat input capacity greater than 250 MMBtu/hr, Section 5.1.2 establishes an SO_2 limit of 0.8 lb/MMBtu actual heat input. Again, the potential SO_2 emission factor from combusting natural gas in the Mill Creek Generating Station's Regulation 7.06 affected units is orders of magnitude lower than the allowable SO_2 emission rate, so LG&E will be implicitly in compliance with these emission limits when burning natural gas.

5.7.5.4 Regulation 7.08 – New Process Operations

This regulation establishes emissions limitations from new process operations, unless those emissions are otherwise regulated under another part of Regulation 7. PM emissions from the cooling tower will be regulated under this generally applicable regulation.

5.7.5.5 Regulation 7.09 – New Process Gas Streams

This regulation establishes emissions limitations for hydrogen sulfide, SO_2, and CO from new process gas streams (defined as gas stream emitted from any process), unless those emissions are otherwise regulated under another part of Regulation 7.

The SO_2 standard under Regulation 7.09 (28.63 grains/100 dscf) is less stringent than the standard under NSPS KKKK (0.06 lb/MMBtu). According to Regulation 7.02, Section 5, the combustion turbines are not subject to the SO_2 standard under Regulation 7.09. Also, the combustion process in the turbines is greater than 1,300°F for 0.5 second. Therefore, there is no monitoring, record keeping, and reporting requirements with respect to the CO standard under Regulation 7.09. The combustion turbine is not a quantifiable source of hydrogen sulfide emissions.

5.7.5.6 Regulation 7.12 – Standards of Performance for New Storage Vessels for VOC

Regulation 7.12 contains provisions to limit VOC emissions from storage tanks. The diesel storage tanks associated with the emergency generator and fire pump engines are affected facilities for Regulation 7.12; however, because the true vapor pressure of the VOCs that will be stored are not equal to or greater than 1.5 psia, there are no applicable emissions limits or operational restrictions.

5.7.5.7 Regulation 7.25 – Standards of Performance for New Sources Using Volatile Organic Compounds

Regulation 7.25 applies to each affected facility not elsewhere regulated in Regulation 7 for VOCs. An affected facility must use VOCs and have a VOC PTE of greater than 5 tpy. The combustion turbine lube oil system does use VOCs, however, VOC emissions from the lube oil demister vents are less than 5 tpy. Thus, the requirement to implement best available control technologies (BACT) does not apply under this regulation.

5.8 STAR Program

The proposed project will be subject to the Louisville STAR requirements (Regulation 5.01) for all regulated toxic air contaminants (TAC) that will be emitted at Mill Creek Generating Station. As demonstrated herein, the proposed NGCC Project, in conjunction with the existing emission units, will comply with all STAR requirements for all TAC emitted at the facility following the completion of the proposed project.

5.8.1.1 De Minimis Source Documentations

To determine which emissions units will need to be evaluated under the requirements of the STAR program, it is important to determine which emission units meet the de minimis source criteria identified in APCD Regulation 5.21, Section 2 and thus will be exempt from further action under the STAR program.

The existing units with the potential to emit toxic air contaminants above *de minimis* levels that will remain at the facility include two coal-fired boilers (EGU Unit 3 [U3] and EGU Unit 4 [U4]), fly-ash storage and handling equipment, and the landfill operations. As documented in the existing Title V permit (O-0127-20-V), a STAR Environmental Acceptability (EA) Demonstration including each of these existing emission units was most recently approved by APCD on January 21, 2016. The remaining existing emission units qualify for *de minimis* exemption from STAR requirements.

Section 3 of this application report provides a full list of emission generating units that will be installed as part of the NGCC Project. From this list, the cooling tower and the lube oil system will not have quantifiable emissions of toxic air pollutants and will not be considered as part of this analysis. Emissions from all natural-gas fired combustion equipment, pursuant to Regulation 5.21 Section 2.7, are considered *de minimis*; therefore, all natural-gas fired combustion equipment will be exempt from the requirements of the STAR program. Regulation 5.11 Section 2.3 declares that items that are listed as insignificant activities in Title V permits also meet the *de minimis* source criteria. LG&E expects that the diesel storage tanks and fire pump engine will be listed as insignificant activities and will thus meet the *de minimis* source criteria.

The only new emission generating unit remaining that is part of the NGCC Project that will be subject to the requirements of the STAR program will be the diesel-fired emergency generator engine (unless APCD determines that this unit is an insignificant activity as defined in Regulation 2.16). Full documentation of a pollutant-by-pollutant *de minimis* determination is included in the following paragraph, based upon an operating restriction of 500 hours per year.

APCD Regulation 5.21 Section 2 states that emissions from a process are *de minimis* if the allowed emissions of a TAC from the process or process equipment are equal to or less than *de minimis* values calculated using the Benchmark Ambient Concentration (BAC) for the TAC. Annual emissions from the proposed diesel generator are shown in Table 5-2 and are further detailed in Section 9 of Appendix B. The corresponding BAC-based *de minimis* emission levels for each TAC are also included in Table 5-2. As shown in this table, all TACs with the exception of diesel particulate have annual emissions below the individual process *de minimis* emission rates. Therefore, TAC emissions (with the exception of diesel particulate) from the emergency generator are below *de minimis* thresholds.

5.8.1.2 Tier 4 Methodology

The methodology and findings of a Tier 4 modeling analysis conducted are presented in this section. This analysis demonstrates LG&E's compliance with the STAR program BAC standards for diesel particulate.

5.8.1.2.1 <u>Dispersion Model</u>

For this modeling analysis, the U.S. EPA's AMS/EPA Regulatory Model (AERMOD) (v22112) was selected to determine maximum off-property concentrations. AERMOD is a refined dispersion model that is widely used and accepted in the air quality community for this type of modeling application and has been approved for use in STAR Tier 4 modeling by APCD.

5.8.1.2.2 Emissions Source Data

Diesel particulate emissions from the emergency generator were the only emissions that were modeled as part of this Tier 4 methodology analysis. Table 5-3, below, summarizes the diesel particulate emission rate and stack parameters for the emergency generator stack. The modeled emission rate for diesel particulate emissions (lb/yr) is based on the maximum annual particulate emissions as calculated (as documented in Section 9 of Appendix B), which are based on manufacturer emissions data for a similar engine.

Table 5-2. Generator TAC Potential Emissions and De Minimis Thresholds

Pollutant	CAS #	HAP?	TAC?	Emission Factor (lb/Mgal)	Uncontrolled Emissions (lb/yr)	*De Minimis* Threshold (lb/yr)	Below *De Minimis* ?
Acetaldehyde	75-07-0	Y	Y	3.45E-03	0.237	216.00	Y
Acrolein	107-02-8	Y	Y	1.08E-03	0.074	9.60	Y
Benzene	71-43-2	Y	Y	1.06E-01	7.284	216.00	Y
Formaldehyde	50-00-0	Y	Y	1.08E-02	0.741	36.96	Y
Naphthalene	91-20-3	Y	Y	1.78E-02	1.220	13.92	Y
PAH	--	Y		2.91E-02	1.990		
Toluene	108-88-3	Y	Y	3.85E-02	2.638	2,400,000	Y
Xylenes	1330-20-7	Y	Y	2.64E-02	1.812	48,000	Y
Acenaphthylene	208-96-8	Y	N	1.26E-03	0.087	--	--
Acenaphthene	83-32-9	Y	N	6.41E-04	0.044	--	--
Fluorene	86-73-7	Y	N	1.75E-03	0.120	--	--
Phenanthrene	85-01-8	Y	N	5.59E-03	0.383	--	--
Anthracene	120-12-7	Y	N	1.69E-04	0.012	--	--
Fluoranthene	206-44-0	Y	N	5.52E-04	0.038	--	--
Pyrene	129-00-0	Y	N	5.08E-04	0.035	--	--
Benzo(a)anthracene	56-55-3	Y	Y	8.52E-05	0.006	4.37	Y
Chrysene	218-01-9	Y	Y	2.10E-04	0.014	43.68	Y
Benzo(b)fluoranthene	205-99-2	Y	Y	1.52E-04	0.010	4.37	Y
Benzo(k)fluoranthene	207-08-9	Y	Y	2.99E-05	0.002	4.37	Y
Benzo(a)pyrene	50-32-8	Y	Y	6.16E-04	0.042	0.44	Y
Indeno (1,2,3-cd)pyrene	193-39-5	Y	Y	5.67E-05	0.004	4.37	Y
Dibenz(a,h)anthracene	53-70-3	Y	Y	4.74E-05	0.003	0.40	Y
Benzo(g,h,i)perylene	191-24-2	Y	N	7.62E-05	0.005	--	--
Diesel particulate matter	--	N	Y	1.73E+00	118.258	1.58	**N**

Table 5-3. Generator Engine Stack Parameters

Model ID	Description	DPM Annual Emission Rate (lb/yr)	Stack Height (ft)	Stack Temperature (°F)	Exit Velocity (ft/s)	Diameter (ft)
EGENGINE	Emergency Generator Engine	118.258	16.00	900	152.79	1.50

5.8.1.2.3 Building Downwash

The U.S. EPA's Building Profile Input Program (BPIP) (04274) was utilized to determine building downwash parameters for the modeling analysis. Table 5-4 below contains a summary of the heights of each of the tanks and buildings that will be located at the Mill Creek Generating Station. These tanks and buildings are structures that could potentially result in plume downwash from the generator engine stack.

Table 5-4. Building Heights

Model ID	Description	Building Height (ft)
STEAMBLD	Steam Turbine Building	85.0
FIREWATR	Fire Water Tank	54.0
DEMINTNK	Demin Water Storage Tank	45.0
WASTTANK	Wastewater Tank	27.0
COOLTWER	Cooling Tower	55.0
ADMIN	Administration Building	15.0
GASCOMP	Gas Compressor Building	33.0
STARTENC	Start Enclosure	16.0
BATTENC	Battery Enclosure	16.0
CTS01-08	Cooling Tower Cell #1-#8 Stack	55.0
CHEMBLDG	Circulating Water Chemical Feed Building	15.0
AUXBLDG	Auxiliary Boiler Building	36.0
FEEDPUMP	Boiler Feed Pump Electrical Building	18.0
NITROTNK	Nitrogen Storage Tank	10.0
WWPUMP	Wastewater Pump Skid	12.0
PDCBLDG	PDC Building	16.0
PEEC	Single Shaft PEEC	16.0
TURBPENT	Turbine Building Penthouse	145.0
TURBANC	Ancillary Turbine Structure	48.2
EMERGENC	Emergency Generator Enclosure	15.0
SAMPPAN	Sample Panel	12.0
CYCLE	Cycle Chemical Feed	16.0
GASTURBF	Gas Turbine Inlet Filter	55.0
CIRCPUMP	Circ Water Pumps	12.0
GASYARD	Gas Yard	15.0
GSUTRANS	GSU Transformer	45.0
AMMCONT	Ammonia Flow Control	10.0
DUCTSKID	Duct Burner Skid	12.0
RECIRCP	HRSG Recirculation Pump Enclosure	12.0
CEMSSH	CEMS Shelter	12.0
UNITAUX	Unit Auxiliary Transformers	15.0
PUMPHS	Pump Enclosure	12.0
AMMOUNLO	Ammonia Unloading/Storage/Forwarding	20.0
CO2TANK	CO2 Storage Tank	10.0
SPAREGSU	Spare GSU Transformer	35.0

5.8.1.2.4 Receptor Grids and Terrain

Multiple modeling grids were used in order to provide a detailed mapping of ground-level, off-property concentrations in areas immediately surrounding the Mill Creek Generating Station property. The first grid extends from the facility center out to 3 km and includes receptors at 100 m spacing. The second grid is from 3 km out to 5 km and includes receptors at 250 m spacing. The fourth grid is from 5 km out to 10 km and includes receptors at 500 m spacing. The fifth grid is from 10 km out to 20 km and includes receptors at 1,000 m spacing. The final grid is from 20 km to 50 km and includes receptors at 2,000 m spacing. Additionally, receptors were placed along the property line of the facility at a 50-meter density.

Since terrain elevations are of interest in this project due to the facility's location near the Ohio River, digital elevation data for the Louisville area were obtained from the USGS and imported into the modeling runs for each receptor location. Stack and building elevations were based on an estimated facility-grade level for the NGCC Unit.

5.8.1.2.5 Meteorological Data

The five most recent years of valid meteorological data available from APCD from the nearest representative National Weather Service (NWS) stations are utilized in the analysis. 2015-2019 surface data from the NWS station at the Louisville International Airport-Standiford Field in Louisville, Kentucky (NWS Station No. 93821) are combined with corresponding years of atmospheric sounding data from Wilmington, Ohio (NWS Station No. 13841) in order to generate the model-ready meteorological data files. These meteorological data files were obtained from the APCD website.[64]

5.8.1.2.6 Modeling Results

Table 5-5 summarizes the results of the LG&E Tier 4 STAR modeling analysis for all public receptors. The maximum ground-level, off-property public receptor concentration for emissions of diesel particulate (in micrograms per cubic meter [$\mu g/m^3$]) associated with emergency generator operation is listed for an average of the five modeled years. These values are divided by the BAC for diesel particulate (0.0033 $\mu g/m^3$) to calculate the carcinogenic risk (R_C) associated with the emergency generator emissions. This value is less than 1.0, which is the environmental acceptability goal (EAG) for individual processes as defined in APCD Regulation 5.21 Section 3.1.

Additionally, diesel particulate has a noncarcinogenic benchmark ambient concentration (BAC_{NC}) of 5.00 $\mu g/m^3$ with an annual averaging period. Given the BAC_C is much more stringent than the BAC_{NC}, compliance with the carcinogenic value also indicates compliance with the noncarcinogenic value and as such the BAC_{NC} was not evaluated against in this modeling analysis.

Table 5-5. Tier 4 STAR Modeling Results

Model ID	Averaging Period	BAC_C Diesel Particulate ($\mu g/m^3$)	Maximum Impact ($\mu g/m^3$)	UTM East[2] (m)	UTM North[2] (m)	R_C
EGENGINE	Period[1]	0.0033	0.00244	596,364	4,212,024	0.74

[1] Evaluated maximum modeled arithmetic mean of the five year modeling period for comparison against the Carcinogenic Benchmark Ambient Concentration (BAC_C).

[2] UTM coordinates are in NAD83 Zone 16.

[64] Meteorological Data for Dispersion Modeling, https://louisvilleky.gov/government/air-pollution-control-district/meteorological-data-dispersion-modeling

As indicated in the current Title V permit (O-0127-20-V), the January 21, 2016 EA Demonstration was based on SCREEN3 dispersion modeling. To determine the facility-wide cumulative risk, the "worst-case" modeled impact for each source was determined using the SCREEN3 dispersion model and then these impacts were added together. SCREEN3 determined the "worst-case" impact irrespective of receptor direction from the modeled sources.

To demonstrate compliance with the facility-wide cumulative carcinogenic risk goals (shown in Table 5-6), the facility-wide R_C from the January 2016 EA demonstration was added to the R_C calculated for the proposed generator engine. This approach is conservative because the maximum modeled impact location for the emergency generator engine is unlikely to occur at the same receptor location as all of the previously modeled sources. As shown in in Table 5-6, the calculated post-project carcinogenic risk from all process/process equipment (P/PE) will meet all applicable EA goals.

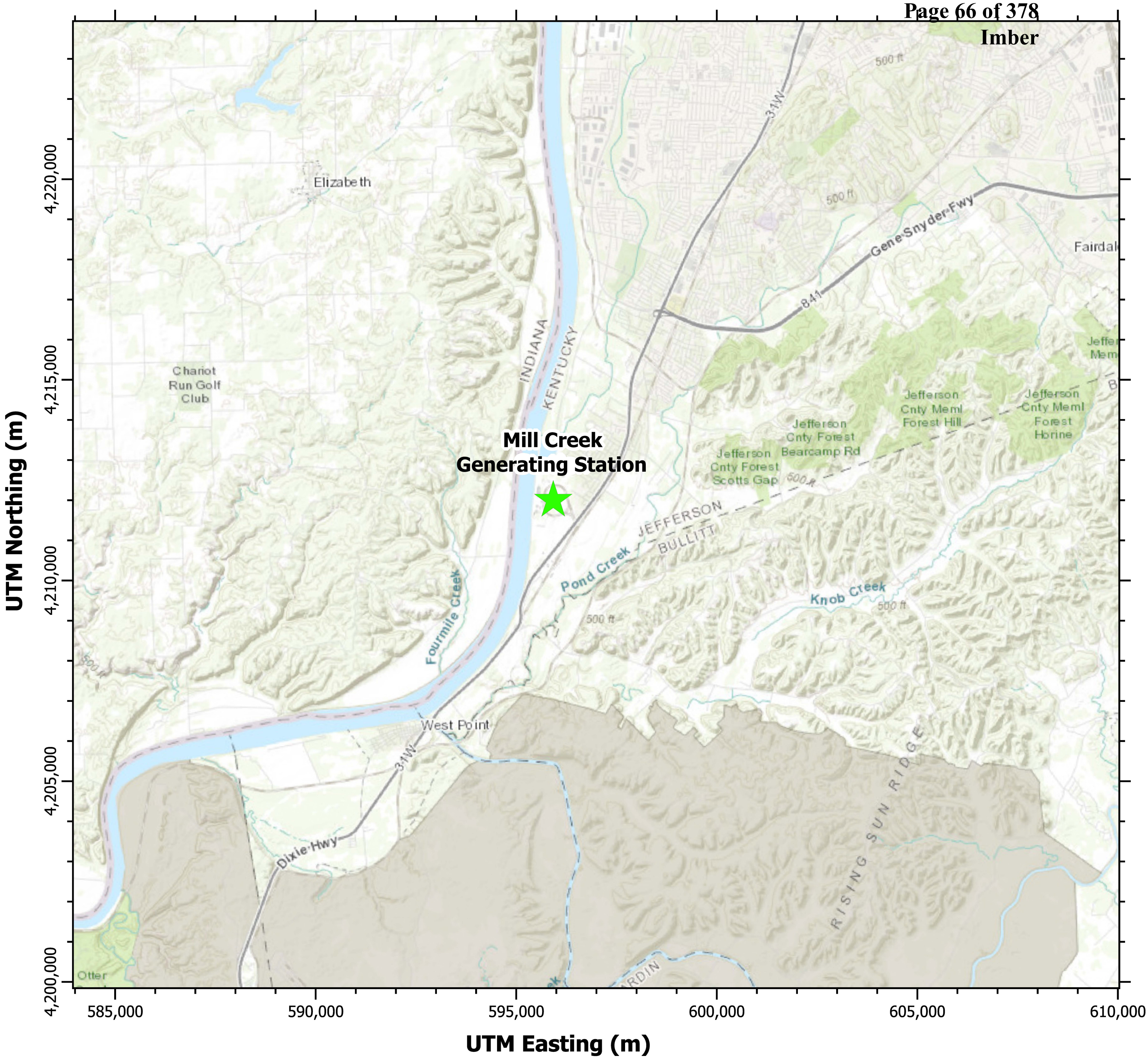
Table 5-6. Facility-wide Cumulative Risk Analysis

Process Equipment	Applicable TACs	EAG_C Risk	Existing Facility[1] R_C	NGCC Project R_C	Total Applicable R_C	Below EAG_C?
Individual P/PE	DPM	1.0	--	0.74	0.74	Yes
All P/PE	All TACs	7.5	4.16	0.74	4.90	Yes
All New and Modified P/PE	All TACs	3.8	--	0.74	0.74	Yes

[1] Facility-wide carcinogenic risk (4.16) was taken from most recent STAR EA demonstration submitted to APCD January 21, 2016 as documented in the current Title V permit (O-0127-20-V). This risk value conservatively includes risk associated with EGU Unit 1 (U-1) and EGU Unit 2 (U-2), which will be shutdown as part of the NGCC project.

All dispersion modeling files will be provided to APCD in electronic format in conjunction with the submittal of this permit application. Model and processor input, output, and data files will also be provided. Spreadsheets tabulating source parameters, emissions, and other input data sets can also be provided upon request.

APPENDIX A. MAPS AND PROCESS FLOW DIAGRAMS



LG&E KU PPL companies LG&E-KU | Louisville, KY	**Figure A-1. Area Map for Mill Creek Generating Station in Louisville, KY**			
CRS: UTM Zone 16 / NAD83 Datum	Scale: 0 2 4 km	N	**Legend** Facility	
Project No: 221801.0123	Trinity Consultants 1717 Dixie Highway, Ste. 900 Covington, KY 41011			

LG&E
a PPL company

Figure A-2 Aerial Map of Mill Creek Generating Station Showing Arrangement of Existing Operations

Generation Services
Document Management

MILL CREEK
"YOU ARE HERE"
BASIC SITE LAYOUT

N

Revisions

A Project: 10358480

INITIAL ISSUE

Dwn: EDC 12/09/2022
Chkd: MAW 12/09/2022
Appd: . -

SITE PLAN

SCALE: 1" = 300'-0"

Figure A-3 Site Arrangement Drawing of New NGCC Unit Operations (Aerial Map Overlay)

NOT TO BE USED FOR CONSTRUCTION

HDR

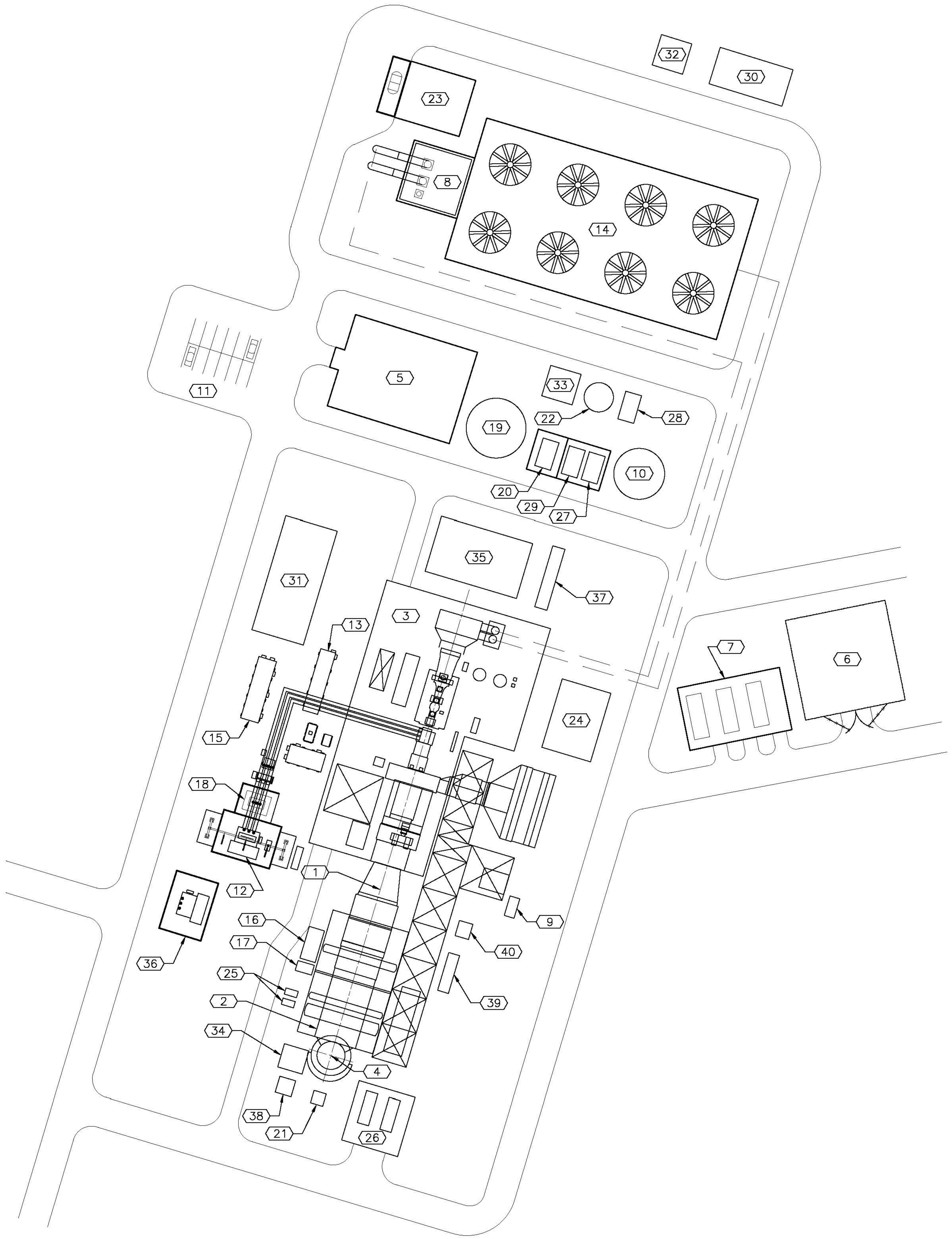
Location and Unit: MILL CREEK		LG&E KU PPL companies Generation Services	Drawn: EDC 12/09/2022
Scale: 1" = 300'-0"	Contract No. -		Checked: MAW 12/09/2022
Engineering discipline: CIVIL	Drawing type: PLAN		Approved: . -
Title: COMBINED CYCLE GENERATION PROGRAM MILL CREEK UNIT 5 SITE PLAN			Released for: REVIEW
			Alternate Drawing No: C1000
Originator: HDR ENGINEERING, INC	Job or Project No: 10358480	Drawing No: 5GA-C1000	Rev. A

DMS Version 2.0

10358480 5GA-C1000 A

Figure A-4 Site Arrangement Drawing of New NGCC Unit Operations

10343340 0GA-C1101 A



1. GAS TURBINE (GT)
2. HEAT RECOVERY STEAM GENERATOR (HRSG)
3. STEAM TURBINE BUILDING
4. HRSG STACK
5. ADMINISTRATION/CONTROL BUILDING
6. GAS YARD
7. GAS COMPRESSOR BUILDING
8. CIRC WATER PUMPS
9. EMERGENCY GENERATOR
10. DEMIN WATER STORAGE TANK
11. PLANT PARKING
12. GSU TRANSFORMER
13. BATTERY ENCLOSURE
14. COOLING TOWER
15. EXCITATION/STATIC START ENCLOSURE
16. AMMONIA FLOW CONTROL
17. DUCT BURNER SKID
18. UNIT AUX TRANSFORMERS
19. SERVICE/FIRE WATER STORAGE TANK
20. FIRE PROTECTION PUMP HOUSE
21. CEMS SHELTER
22. WASTE WATER TANK
23. CIRC. WATER CHEMICAL FEED BUILDING
24. AUXILIARY BOILER BUILDING
25. HRSG RECIRCULATION PUMPS
26. BOILER FEED PUMP/ELECTRICAL BUILDING
27. DEMIN FORWARDING PUMPS
28. WASTE WATER PUMP SKID
29. SERVICE WATER PUMP SKID
30. AMMONIA UNLOADING/STORAGE/FORWARDING
31. SINGLE SHAFT PEECC
32. CO2 BULK STORAGE TANK
33. NITROGEN STORAGE TANK
34. HRSG BLOWDOWN TANK/PIT
35. MEDIUM VOLTAGE PDC
36. SPARE GSU TRANSFORMER
37. OIL/WATER SEPARATOR
38. HRSG BLOWDOWN SUMP
39. SAMPLE PANEL
40. CYCLE CHEMICAL FEED

Revisions

A Project: 10343340
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07 OCT 2022

Dwn: SDK
Chkd:
Appd:

Figure A-5 Site Arrangement Drawing of New NGCC Unit Structures and Equipment

N

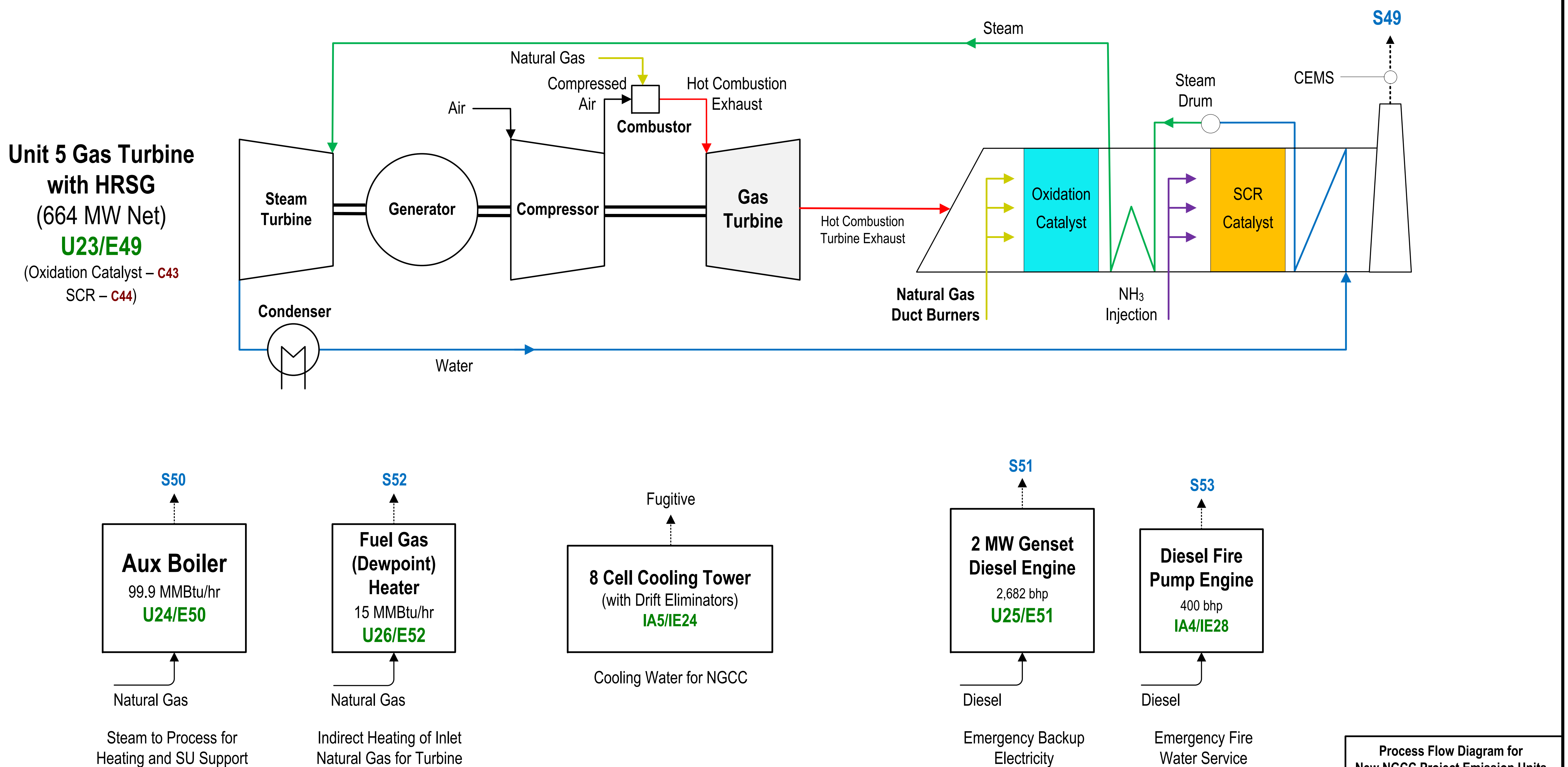
SITE PLAN
SCALE: 1" = 300'-0"
300 0 300 600 900

NOT TO BE USED FOR CONSTRUCTION

HDR

Location and Unit: MILL CREEK	LG&E KU PPL companies	Generation Services	Drawn: ASK
Scale: None / Contract No.: -			Checked:
Engineering discipline: CIVIL / Drawing type:			Approved:
Title: MILL CREEK GENERAL ARRANGEMENT SINGLE UNIT NGCC			Released for: INFORMATION
Originator: HDR, INC.	Job or Project No: 10343340	Drawing No: 0GA-C1101	Rev: A

Figure A-6 Process Flow Diagram for New Emission Units Associated with NGCC Project



Emission Unit and Emission Point IDs are shown in green.
Control Device IDs are shown in maroon.
Release Point IDs are shown in blue.

Flow Legend
Process Flow
Gaseous or Emissions Flow

Process Flow Diagram for New NGCC Project Emission Units
LG&E
Mill Creek Station

Revised: December 13, 2022
Project # 221801.0123

Trinity Consultants
1717 Dixie Hwy, Ste. 900
Covington, KY 41011

APPENDIX B. EMISSIONS UNIT INDEX AND CALCULATIONS

An inventory of existing and new emission units at the Mill Creek Generating Station is provided in this appendix along with documentation showing the methodology for defining potential emissions from the new emission units associated with the NGCC Project (as reflected on the APCD application forms provided in Appendix C) and the baseline actual emissions for existing emission units that are being shut down. The appendix is split up into the following 19 sections:

1. Mill Creek Generating Station Emission Unit Index
2. Project Emissions Increases Summary Table

Potential Emissions from New NGCC Project Emission Units

3. Potential Emissions Summary for New NGCC Project Emission Units
4. Potential Emissions for Gas Turbine/Duct Burners Based on Prospective Vendor Data
5. Unit 5 Gas Turbine with HRSG/Duct Burners - Emission Calculations
6. Auxiliary Steam Boiler - Emissions Calculations
7. Fuel Gas (Dewpoint) Preheater - Emissions Calculations
8. Mechanical Draft Cooling Tower – Emissions Calculations
9. Diesel-Fired Emergency Generator Engine - Emissions Calculations
10. Diesel-Fired Emergency Fire Pump Engine - Emissions Calculations *[Insignificant Activity]*
11. HVAC Heaters – Emissions Calculations *[Insignificant Activity]*
12. Lube Oil Demister Vents - Emission Calculations *[Insignificant Activity]*
13. Diesel Storage Tanks – Emissions Calculations *[Insignificant Activity]*

Baseline Actual Emissions from Existing Emission Units Being Shut Down

14. Mill Creek Unit 1 and 2 Boilers - Emission Reductions from Shutdowns
15. Mill Creek Unit 1 and 2 Coal Bunkers – Emission Reductions from Shutdowns
16. Mill Creek Unit 1 and 2 Coal Bunkers - Emission Reductions from Shutdowns
17. Mill Creek Unit 1 and 2 Flyash Transfer Bin – Emission Reductions from Shutdowns
18. Mill Creek Unit 1 and 2 Sorbent and PAC Silos - Emission Reductions from Shutdowns
19. Mill Creek Unit 2 Cooling Tower - Emission Reductions from Shutdown

1. Mill Creek Generating Station Emission Unit Index

> The following table provides an index of existing emission units at the Mill Creek Generating Station along with new emission units being installed as part of the proposed NGCC Project. Existing units being shutdown are highlighted in red font. Other than units being shutdown, there are no changes being made to other existing units at the plant as part of the NGCC Project.
> The emission unit ID nomenclature listed for the new emission units (shown in green font) are placeholders, to be finalized by APCD upon issuance of construction permit and revised Title V operating permit.

Emission Unit	Emission Point	Emission Unit Description	Emission Point Description	Control ID(s)	Control Description	Release ID(s)	Project Impacts
U1	E1	EGU Unit 1	Unit 1 Boiler (3,085 MMBtu/hr)	C1, C26, C27	ESP, PAC Injection, DSI, PJFF,	S33	**Shutdown (12/2024)**
U1	E2	EGU Unit 1	Four Coal Silos; Four Coal Mills	C3	Centrifugal Dust Collector	S5	**Shutdown (12/2024)**
U2	E3	EGU Unit 2	Unit 2 Boiler (3,085 MMBtu/hr)	C4, C27, C28	ESP, PAC Injection, DSI, PJFF,	S33	**Shutdown (4/2027)**
U2	E4	EGU Unit 2	Four Coal Silos; Four Coal Mills	C6	Centrifugal Dust Collector	S6	**Shutdown (4/2027)**
U3	E5	EGU Unit 3	Unit 3 Boiler (4,204 MMBtu/hr)	C7, C22, C29, C39	ESP, SCR, PAC Injection, DSI, PJFF, FGD	S4	Existing Unaffected
U3	E6	EGU Unit 3	Four Coal Silos; Four Coal Mills	C9	Centrifugal Dust Collector	S7	Existing Unaffected
U4	E7	EGU Unit 4	Unit 4 Boiler (5,025 MMBtu/hr)	C10, C23, C30, C31	ESP, SCR, PAC Injection, DSI, PJFF, FGD	S34	Existing Unaffected
U4	E8	EGU Unit 4	Five Coal Silos; Five Coal Mills	C12	Centrifugal Dust Collector	S8	Existing Unaffected
U8	E13	Fly Ash Storage & Handling	Flyash Silos A & B	C15a, C16	Cartridge Dust Collector; Baghouse	S13, S14	Existing Unaffected
U8	E31	Fly Ash Storage & Handling	Silos A & B Dry Truck Load-Outs	C37, C38	Air Slider Filter; Loading Spout Filter	S43, S43	Existing Unaffected
U8	E32	Fly Ash Storage & Handling	Silos A & B Railcar Load-Outs	C24a, C25a	Cartridge Filter Dust Collectors (2)	S22, S23	Existing Unaffected
U8	E33	Fly Ash Storage & Handling	Silos A & B Wet Truck Load-Outs	--	--	Fugitive	Existing Unaffected
U9	E16	Fly Ash Transfer Bins	Flyash Transfer Bin with Two Separators for Units 1 & 2	C19	Baghouse	S17, S24, S25	**Shutdown (4/2027)**
U9	E17	Fly Ash Transfer Bins	Flyash Transfer Bin with Two Separators for Unit 3	C20	Baghouse	S18, S26, S27	Existing Unaffected
U9	E18	Fly Ash Transfer Bins	Flyash Transfer Bin with Two Separators for Unit 4	C21	Baghouse	S19, S28, S29	Existing Unaffected
U12	E24	Limestone Processing Operations	Barge Unloading Operation (Limestone)	--	--	Fugitive	Existing Unaffected
U12	E25	Limestone Processing Operations	Transfer Point from Conveyor to Storage Pile	--	--	Fugitive	Existing Unaffected
U12	E26	Limestone Processing Operations	Belt Conveyor LA and Transfer to Belt Conveyor LB	--	--	Fugitive	Existing Unaffected
U12	E27	Limestone Processing Operations	Belt Conveyor LB and Transfer to Storage Pile	--	--	Fugitive	Existing Unaffected
U12	E28	Limestone Processing Operations	Three Limestone Crushers	--	--	Fugitive	Existing Unaffected
U14	E38	Cooling Tower	Cooling Tower for Unit 4	--	--	Fugitive	Existing Unaffected
U15	E39a	Haul Roads	Paved Road Particulate Emissions	--	--	Fugitive	Existing Unaffected
U15	E39b	Haul Roads	Unpaved Road Particulate Emissions	--	--	Fugitive	Existing Unaffected
U16	E40a-b	Sorbent Storage Silos	Two of Six Sorbent Silos for Dry Sorbent or Trona	C32a-b	Bin Vent Filters	S35a-b	**Shutdown (4/2027)**
U16	E40c-f	Sorbent Storage Silos	Four of Six Sorbent Silos for Dry Sorbent or Trona	C32c-f	Bin Vent Filters	S35c-f	Existing Unaffected
U17	E41a-b	PAC Storage Silos	Two of Six PAC Silos for PAC Injection System	C33a-b	Bin Vent Filters	S36a-b	**Shutdown (4/2027)**
U17	E41c-f	PAC Storage Silos	Four of Six PAC Silos for PAC Injection System	C33c-f	Bin Vent Filters	S36c-f	Existing Unaffected
U18	E42	Fly Ash Storage Silos	One or More Flyash Silo for PJFF Units	C34	Bin Vent Filters	S37	Existing Unaffected
U20	E44a	Gypsum Pelletizing Plant	Load Hopper for Gypsum Receiving	C36	Baghouse	S39	Existing Unaffected
U20	E44b	Gypsum Pelletizing Plant	Conveyor (Hopper to Dispersion Dryer)	C36	Baghouse	S39	Existing Unaffected
U20	E44c	Gypsum Pelletizing Plant	Allgaier Dispersion Dryer	--	--	Fugitive	Existing Unaffected
U20	E44d	Gypsum Pelletizing Plant	Pneumatic Conveyor with Cyclone (BH to Load Hopper)	--	--	Fugitive	Existing Unaffected
U20	E44e	Gypsum Pelletizing Plant	Mixer Load Hopper	--	--	Fugitive	Existing Unaffected
U20	E44f	Gypsum Pelletizing Plant	Rotary Airlock Conveyor (Mixer Hopper to Pin Mixer)	--	--	Fugitive	Existing Unaffected

Emission Unit	Emission Point	Emission Unit Description	Emission Point Description	Control ID(s)	Control Description	Release ID(s)	Imber Project Impacts
U20	E44g	Gypsum Pelletizing Plant	Pin or Plow Mixer with Lingo Sulfonate Storage Tank	--	--	Fugitive	Existing Unaffected
U20	E44h	Gypsum Pelletizing Plant	Belt Conveyor (Pin Mixer to Disc Pelletizer)	--	--	Fugitive	Existing Unaffected
U20	E44i	Gypsum Pelletizing Plant	DISC Pelletizer	--	--	Fugitive	Existing Unaffected
U20	E44j	Gypsum Pelletizing Plant	Belt Conveyor (Disc Pelletizer to Fluid Bed Dryer)	--	--	Fugitive	Existing Unaffected
U20	E44k	Gypsum Pelletizing Plant	Allgaier Vibrating Fluid Bed Dryer	--	--	Fugitive	Existing Unaffected
U20	E44l	Gypsum Pelletizing Plant	Mogensen Sizer/Screener	--	--	Fugitive	Existing Unaffected
U20	E44m	Gypsum Pelletizing Plant	Belt Conveyor (Screener to Product Pile)	--	--	Fugitive	Existing Unaffected
U20	E44n	Gypsum Pelletizing Plant	Hammer Mill	--	--	Fugitive	Existing Unaffected
U20	E44o	Gypsum Pelletizing Plant	Limestone Silo with Integrated Bin Vent Filters	--	--	Fugitive	Existing Unaffected
U20	E44p	Gypsum Pelletizing Plant	De-Dust System with Tanks, Conveyors, Mixer, Elevators	--	--	Fugitive	Existing Unaffected
U20	E45	Gypsum Pelletizing Plant	NG Direct-Fired Heater for Dispersion Dryer (42	--	--	S40	Existing Unaffected
U20	E46	Gypsum Pelletizing Plant	NG Direct-Fired Heater for Fluid Bed Dryer (42 MMBtu/hr)	--	--	S41	Existing Unaffected
U21	E47a	Coal Handling	Barge Unloading Operation (Coal)	--	--	Fugitive	Existing*
U21	E47b	Coal Handling	Railcar Unloading (Coal)	--	--	Fugitive	Existing*
U21	E47c	Coal Handling	Coal Radial Stacker	--	--	Fugitive	Existing*
U21	E47d	Coal Handling	Two Coal Crushers	--	--	Fugitive	Existing*
U21	E47e1-16	Coal Handling	Coal Belt Conveyors	--	--	Fugitive	Existing*
U21	E47f	Coal Handling	Coal Storage Pile (Drop Point Emission)	--	--	Fugitive	Existing*
U21	E47g	Coal Handling	Fuel Additive Facility (2 Silos; Hopper; Mix Tank; Heater)	--	--	Fugitive	Existing Unaffected
U22	E48a	Landfill	Landfill Haul Roads	--	--	Fugitive	Existing Unaffected
U22	E48b	Landfill	Landfill Drop Points	--	--	Fugitive	Existing Unaffected
U22	E48c	Landfill	Landfill Wind Erosion Emissions	--	--	Fugitive	Existing Unaffected
U23	**E49a**	**EGU Unit 5 Gas Turbine with HRSG**	**Natural Gas Firing in GT & DB**	**C43, C44**	**Oxidation Catalyst; SCR**	**S49**	**New (4/2027)**
U23	**E49b**	**EGU Unit 5 Gas Turbine with HRSG**	**Cold Startup Events**	**--**	**--**	**S49**	**New (4/2027)**
U23	**E49c**	**EGU Unit 5 Gas Turbine with HRSG**	**Warm Startup Events**	**--**	**--**	**S49**	**New (4/2027)**
U23	**E49d**	**EGU Unit 5 Gas Turbine with HRSG**	**Hot Startup Events**	**--**	**--**	**S49**	**New (4/2027)**
U23	**E49e**	**EGU Unit 5 Gas Turbine with HRSG**	**Shutdown Events**	**--**	**--**	**S49**	**New (4/2027)**
U24	**E50**	**Auxiliary Steam Boiler**	**Natural Gas Combustion w/ LNB & FGR**	**--**	**--**	**S50**	**New (4/2027)**
U25	**E51**	**2 MW Diesel Emergency Generator**	**Diesel Fuel Combustion**	**--**	**--**	**S51**	**New (4/2027)**
U26	**E52**	**Fuel Gas (Dewpoint) Heater**	**NG Fuel Combustion (15 MMBtu/hr)**	**--**	**--**	**S52**	**New (4/2027)**
IA1	E20	Gasoline Storage Tank	Stage I Gasoline Refueling Station with 3,000 Gallon Tank	--	--	Fugitive	Existing Unaffected
IA2	IE1-8	Parts Washers	Eight Parts Washers Equipped with Secondary Reservoirs	--	--	Fugitive	Existing Unaffected
IA3	E36	Emergency Generators	Turning Gear Diesel Generator (800 hp)	--	--	Fugitive	Existing Unaffected
IA3	E37	Emergency Generators	FGD Quench Water System Diesel Generator (800 hp)	--	--	Fugitive	Existing Unaffected
IA3	IE24	Emergency Generators	NG Fired Emergency Generator (105 hp)	--	--	Fugitive	Existing Unaffected
IA4	IE9	Fire Pump Engines	Diesel Fire Pump Engine (157 hp)	--	--	Fugitive	Existing Unaffected
IA4	IE10	Fire Pump Engines	Diesel Fire Pump Engine (183 hp)	--	--	Fugitive	Existing Unaffected
IA4	**IE28**	**400 HP Diesel Driven Fire Pump**	**Diesel Fuel Combustion**	**--**	**--**	**S53**	**New (4/2027)**
IA5	IE11	Other Insignificant Activities	17 Lubricating Oil Tanks (400 - 20,000 gal capacities)	--	--	Fugitive	Existing Unaffected
IA5	IE12	Other Insignificant Activities	1,000 Gallon #1 Fuel Oil Tank	--	--	Fugitive	Existing Unaffected
IA5	IE13	Other Insignificant Activities	Portable Kerosene Storage Tank (< 500 gal)	--	--	Fugitive	Existing Unaffected
IA5	IE14a	Other Insignificant Activities	Cooling Tower for Unit 2	--	--	Fugitive	**Shutdown (4/2027)**

Emission Unit	Emission Point	Emission Unit Description	Emission Point Description	Control ID(s)	Control Description	Release ID(s)	Project Impacts
IA5	IE14b	Other Insignificant Activities	Cooling Tower for Unit 3			Fugitive	Existing Unaffected
IA5	IE15	Other Insignificant Activities	Gypsum Handling Equipment	--	--	Fugitive	Existing Unaffected
IA5		Other Insignificant Activities	Portable Gypsum Dewatering Systems	--	--	Fugitive	Existing Unaffected
IA5	IE17	Other Insignificant Activities	Bottom/Fly Ash Storage Silo with Bin Vent Filter (IE17)	C40	Bin Vent Filter	S30	Existing Unaffected
IA5	IE18	Other Insignificant Activities	Bottom/Fly Ash Storage Silo with Bin Vent Filter (IE18)	C31	Bin Vent Filter	S31	Existing Unaffected
IA5	IE19	Other Insignificant Activities	Pug Mill Mixers (IE19)	--	--	Fugitive	Existing Unaffected
IA5	IE20	Other Insignificant Activities	Pug Mill Mixers (IE20)	--	--	Fugitive	Existing Unaffected
IA5	IE21	Other Insignificant Activities	Pug Mill Mixers (IE21)	--	--	Fugitive	Existing Unaffected
IA5	IE22	Other Insignificant Activities	Pug Mill Mixers (IE22)	--	--	Fugitive	Existing Unaffected
IA5	IE23	Other Insignificant Activities	Process Water System (PWS)	C42a, C42b	Bin Vent Filters for Hydrated Lime Silos	S32a, S32b	Existing Unaffected
IA5	**IE24**	**Other Insignificant Activities**	**Mechanical Draft Cooling Tower (8 Cells) for NGCC**	**--**	**--**	**Fugitive**	**New (4/2027)**
IA5	**IE25**	**Other Insignificant Activities**	**Lube Oil Storage Tanks with Demister Vents**	**--**	**--**	**Fugitive**	**New (4/2027)**
IA5	**IE26**	**Other Insignificant Activities**	**Diesel Storage Tanks for NGCC Units (1@ 4,000 gal 1@ 440 gal)**	**--**	**--**	**Fugitive**	**New (4/2027)**
IA5	**IE27**	**Other Insignificant Activities**	**HVAC Heaters (Total 10 MMBtu/hr)**	**--**	**--**	**Fugitive**	**New (4/2027)**
IAz1		Unlabeled Insignificant Activities	Minor NG Combustion Sources < 10 MMBtu/hr	--	--	Fugitive	Existing Unaffected
IAz2		Unlabeled Insignificant Activities	Emergency Relief Vents for Boiler Steam Supply	--	--	Fugitive	Existing Unaffected
IAz3		Unlabeled Insignificant Activities	Lab Exhaust Systems	--	--	Fugitive	Existing Unaffected
IAz4		Unlabeled Insignificant Activities	Ash Pond with Wet Storage	--	--	Fugitive	Existing Unaffected
IAz5		Unlabeled Insignificant Activities	Stack Piles (Coal, Limestone, Gypsum)	--	--	Fugitive	Existing Unaffected
IAz6		Unlabeled Insignificant Activities	Turbine Oil Reservoir Vapor Extractor	--	--	Fugitive	Existing Unaffected
IAz7		Unlabeled Insignificant Activities	Hydrogen Seal Oil Tank Vent	--	--	Fugitive	Existing Unaffected
IAz8		Unlabeled Insignificant Activities	Emergency Vent for U1 and U2 Boilers			Fugitive	**Shutdown (4/2027)**

* Coal handling equipment (U21) will not be modified as part of the project, but activity will be reduced in conjunction with shutdown of Units 1 and 2 boilers. As a result, there will be an emissions decrease.

2. Project Emissions Increases Summary Table

> The table below tallies the emission increases associated with the proposed NGCC Project for all relevant regulated NSR pollutants and compares them to the PSD/NSR major modification thresholds. Values shown for new emission units are their potential emissions, taking into account inherent and proposed operating limitations and control device configurations. Values shown for the existing emission units being shutdown as part of the project have zero projected actual emissions minus their baseline actual emissions calculated in accordance with 40 CFR 52.21(b)(48)(i) and Reg 2.04, Paragraph 1.35. Project emission increases are calculated pursuant to 40 CFR 52.21(a)(2)(iv)(f) and Reg 2.04, Paragraph 2.26.

Emission Unit ID	Description	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	Lead (tpy)	CO_2e (tpy)
New Emission Units											
U23/E49a	EGU Unit 5 Gas Turbine with HRSG	100.10	100.10	100.10	167.17	135.90	47.82	24.54	8.64	0.01	2,149,207
U24/E50	Auxiliary Steam Boiler	1.43	1.43	1.43	15.93	16.16	2.27	0.59	0.045	2.07E-04	51,238
U25/E51	2 MW Diesel Emergency Generator	0.059	0.059	0.059	9.70	0.80	0.21	0.007			768
U26/E52	Fuel Gas (Dewpoint) Heater	0.22	0.22	0.22	2.39	4.90	0.34	0.089	0.007	3.10E-05	7,693
IA4/IE28	400 HP Diesel Driven Fire Pump	0.022	0.022	0.022	0.58	0.18	0.02	0.001			115
IA5/IE24	Mechanical Draft Cooling Tower (8 Cells) for NGCC	2.06	0.97	0.0042							
IA5/IE25	Lube Oil Storage Tanks with Demister Vents						0.66				
IA5/IE26	Diesel Storage Tanks for NGCC Units (1@ 4,000 gal 1@ 440 gal)						0.0011				
IA5/IE27	HVAC Heaters (Total 10 MMBtu/hr)	0.14	0.14	0.14	4.14	3.47	0.23	0.059	0.005	2.07E-05	5,129
Subtotal		104.03	102.94	101.98	199.90	161.42	51.56	25.28	8.70	8.85E-03	2,214,149
Emission Decreases from Units Being Shutdown with Project											
U1/E1	Unit 1 Boiler (3,085 MMBtu/hr)	-194.4	-191.6	-178.0	-2,251	-180.8	-21.6	-551.8	-8.0	-0.02	-1,641,022
U1/E2	EGU Unit 1 - Four Coal Silos; Four Coal Mills	-0.0047	-0.0022	-0.0003							
U2/E3	Unit 2 Boiler (3,085 MMBtu/hr)	-160.5	-158.1	-146.3	-1,985	-154.4	-18.5	-591.5	-0.9	-0.01	-1,409,672
U2/E4	EGU Unit 2 - Four Coal Silos; Four Coal Mills	-0.0041	-0.0019	-0.0003							
U9/E16	Flyash Transfer Bin with Two Separators for Units 1 & 2	-0.3643	-0.1276	-0.1276							
U16/E40a-b	Sorbent Storage Silos - Two of Six Sorbent Silos	-0.0126	-0.0126	-0.0126							
U17/E41a-b	PAC Storage Silos - Two of Six PAC Silos for PAC Injectio	-0.0004	-0.0004	-0.0004							
IA5/IE14a	Other Insignificant Activities - Cooling Tower for Unit 2	-0.0315	-0.0226	-6.9E-05							
Subtotal		-355.3	-349.8	-324.4	-4,236	-335	-40.1	-1,143	-8.9	-0.03	-3,050,694
Emission Decreases from Existing Unmodified Emission Units											
U21/E47	Coal Handling Operations (for Unit 1 Boiler)	-1.70	-0.81	-0.12							
U21/E47	Coal Handling Operations (for Unit 2 Boiler)	-1.46	-0.69	-0.10							
Subtotal		-3.16	-1.49	-0.23							
Emissions Increase Summary											
Project Emission Increases		**-254**	**-248**	**-223**	**-4,036**	**-174**	**11**	**-1,118**	**-0.2**	**-0.024**	**-836,545**
PSD/NSR Major Modification Threshold		25	15	10	40	100	40	40	7	0.6	75,000
Trigger PSD/NSR?		**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

3. Potential Emissions Summary for New NGCC Project Emission Units

> The table below tallies the potential to emit for all new emission units associated with the proposed NGCC Project for all relevant regulated air pollutants.

Emission Unit ID	Description	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	Lead (tpy)	CO_2e (tpy)
New Emission Units											
U23/E49a	EGU Unit 5 Gas Turbine with HRSG	100.10	100.10	100.10	167.17	135.90	47.82	24.54	8.64	0.01	2,149,207
U24/E50	Auxiliary Steam Boiler	1.43	1.43	1.43	15.93	16.16	2.27	0.59	0.045	2.1E-04	51,238
U25/E51	2 MW Diesel Emergency Generator	0.059	0.059	0.059	9.70	0.80	0.21	0.007			768
U26/E52	Fuel Gas (Dewpoint) Heater	0.22	0.22	0.22	2.39	4.90	0.34	0.089	0.007	3.1E-05	7,693
IA4/IE28	400 HP Diesel Driven Fire Pump	0.022	0.022	0.022	0.58	0.18	0.02	0.001			115
IA5/IE24	Mechanical Draft Cooling Tower (8 Cells) for NGCC	2.06	0.97	0.0042							
IA5/IE25	Lube Oil Storage Tanks with Demister Vents						0.66				
IA5/IE26	Diesel Storage Tanks for NGCC Units (1@ 4,000 gal 1@ 440 gal)						0.0011				
IA5/IE27	HVAC Heaters (Total 10 MMBtu/hr)	0.14	0.14	0.14	4.14	3.47	0.23	0.059	0.005	2.07E-05	5,129
Subtotal		104.03	102.94	101.98	199.90	161.42	51.56	25.28	8.70	8.9E-03	2,214,149

Emission Unit ID	Description	NH3 (tpy)	Acetalde-hyde (tpy)	Formalde-hyde	Hexane (tpy)	Toluene (tpy)	Xylenes (tpy)	Nickel (tpy)	Mercury (tpy)	Total HAP (tpy)
New Emission Units										
U23/E49a	EGU Unit 5 Gas Turbine with HRSG	122.76	3.09	3.95	15.47	1.14	0.56	3.61E-02	4.47E-03	25.00
U24/E50	Auxiliary Steam Boiler			3.1E-02	0.74	1.4E-03		8.68E-04	1.07E-04	0.78
U25/E51	2 MW Diesel Emergency Generator		1.2E-04	3.7E-04		1.3E-03	9.1E-04			8.0E-03
U26/E52	Fuel Gas (Dewpoint) Heater			4.7E-03	0.112	2.1E-04		1.30E-04	1.61E-05	0.12
IA4/IE28	400 HP Diesel Driven Fire Pump		5.4E-04	8.3E-04		2.9E-04	2.0E-04			2.8E-03
IA5/IE24	Mechanical Draft Cooling Tower (8 Cells) for NGCC									
IA5/IE25	Lube Oil Storage Tanks with Demister Vents									
IA5/IE26	Diesel Storage Tanks for NGCC Units (1@ 4,000 gal 1@ 440 gal)									
IA5/IE27	HVAC Heaters (Total 10 MMBtu/hr)			3.1E-03	7.4E-02	1.4E-04		8.7E-05	1.1E-05	0.078
Subtotal		122.76	3.09	3.99	16.40	1.14	0.56	0.04	4.6E-03	25.98

4. Potential Emissions for Gas Turbine/Duct Burners Based on Prospective Vendor Data

> LG&E is choosing between three vendors for the new 640-664 MW (net) natural gas combined cycle electric generating plant (herein labeled as NGCC). Sections 4 and 5 provide the derivation of the emission factors, heat input, and potential emissions. The NGCC system will consist of one power block with one NG-fired gas turbine (GT) and its single-shaft water cooled generator, one heat recovery steam generator (HRSG) with NG-fired duct burners (DB), and one steam turbine generator (STG) arranged in a one-on-one configuration. The GT will be either a 1x1 7HA.03, 501JAC, 1x1 9000HL, or similar unit, all of which are the largest and most efficient turbines currently in the market.

> Each vendor provided emissions data for a number of cases that bracket the range of possible operating conditions such as the coldest/hottest day, a representative winter day at 15°F, average temperature day at 57°F, and representative summer day at 90°F. The following shows the highest emissions profile at 15, 57, and 90°F, as well as the outlier cases, with the highest hourly emissions rate by pollutant. If the DB is also operational and providing additional heat input, such as during the summer cases, it is shown as well in the load description. Not shown are 75% or minimum load situations because in every one of those low load cases, the hourly emissions rate is less than the corresponding 100% load case. Another variation that occurred in the summer months was the possible operation of an evaporative cooler (EC).

4.1 Vendor A: Calculated Stack Emission Rates for GT/DB

Case	Ambient Temp. (°F)	Load (%)	Load Description	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Total PM (lb/hr)	SO_2 (lb/hr)	H_2SO_4* (lb/hr)	NH_3 (lb/hr)	CO_2 (lb/hr)
4	15	100	GT	30.6	18.6	5.3	18.0	7.1	4.8	28.3	548,000
10	57	100	GT	30.0	18.3	5.2	17.9	7.0	4.7	27.8	537,000
13	90	100	GT + EC + DB	30.6	18.6	**10.7**	19.4	7.1	**5.1**	28.3	547,000
17	106	100	GT + EC + DB	29.8	18.2	10.4	**19.7**	6.9	5.0	27.6	534,000
1	-18	100	GT	**30.7**	**18.7**	5.3	18.0	7.1	4.8	**28.4**	**549,000**
Max of 20		Varies		**30.7**	**18.7**	**10.7**	**19.7**	**7.1**	**5.1**	**28.4**	**549,000**

* When asked by LG&E to provide emissions for H2SO4, only Vendor A provided data. H2SO4 is generated from the following simplified chemical conversion: Fuel-based sulfur => SO2 => SO3 => H2SO4. SO3 is generated in the combustion process and varies depending on both the chosen oxidation catalyst and SCR catalyst. Vender A's overly conservative conversion rates for SO3 generation resulted in H2SO4 hourly emissions being 70% of SO2. As shown in Section 5.3.1, LG&E used a more realistic, yet conservative, conversion rate.

Startup/Shutdown Events	NO_X	CO	VOC	Total PM	SO_2	H_2SO_4	NH_3	CO_2
5 cold start events (total pounds)	2,100	1,550	500	160	-	-	-	-
45 warm start events (total pounds)	11,700	10,350	3,825	1,215	-	-	-	-
100 hot start events (total pounds)	13,500	20,000	8,000	1,400	-	-	-	-
150 shutdown start events (total pounds)	6,000	26,250	9,000	750	-	-	-	-
Sum of all Events (total tons)	**16.7**	29.1	10.7	**1.8**	-	-	-	-

Sample Calculations:
Total Emissions from SUSD Events: NOx (tpy) = (2,100 lb for C-SU + 11,700 lb for W-SU + 13,500 lb for H-SU + 6,000 lb for Shutdowns) / 2,000 lb/ton = 16.7 tpy

4.2 Vendor B: Calculated Stack Emission Rates for GT/DB

Case	Ambient Temp. (°F)	Load (%)	Load Description	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Total PM (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)	NH_3 (lb/hr)	CO_2 (lb/hr)
16	15	100	GT	31.0	19.0	5.3	19.9	-	-	-	-
12	57	100	GT	31.0	19.0	5.4	20.1	-	-	-	-
5	90	100	GT + EC + DB	**32.0**	**19.0**	**10.9**	**23.3**	-	-	-	-
Max of 11		Varies		**32.0**	**19.0**	**10.9**	**23.3**	-	-	-	-

Startup/Shutdown Events	NO_X	CO	VOC	Total PM	SO_2	H_2SO_4	NH_3	CO_2
5 cold start events (total pounds)	360	2,665	675	150	-	-	-	-
45 warm start events (total pounds)	2,925	21,420	5,445	1,125	-	-	-	-
100 hot start events (total pounds)	5,500	30,300	9,100	1,500	-	-	-	-
150 shutdown start events (total pounds)	11,700	29,250	17,700	750	-	-	-	-
Sum of all Events (total tons)	10.2	**41.8**	**16.5**	1.8	-	-	-	-

4.3 Vendor C: Calculated Stack Emission Rates for GT/DB

Case	Ambient Temp. (°F)	Load (%)	Load Description	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Total PM (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)	NH_3 (lb/hr)	CO_2 (lb/hr)
15	15	100	GT	30.1	18.3	5.3	14.9	-	-	27.9	-
9	57	100	GT	28.8	17.5	5.0	14.1	-	-	26.6	-
21	90	100	GT + EC + DB	29.6	18.0	**10.3**	**16.4**	-	-	27.4	-
18	-18	100	GT + EC	**30.2**	**18.4**	5.3	14.9	-	-	**28.0**	-
Max of 21		Varies		**29.6**	**18**	**10.3**	**16.4**	-	-	**27.4**	-

Startup/Shutdown Events	NO_X	CO	VOC	Total PM	SO_2	H_2SO_4	NH_3	CO_2
5 cold start events (total pounds)	540	3,790	350	33	-	-	-	-
45 warm start events (total pounds)	2,655	12,825	2,025	216	-	-	-	-
100 hot start events (total pounds)	5,900	28,500	4,500	480	-	-	-	-
150 shutdown start events (total pounds)	6,900	36,600	7,350	600	-	-	-	-
Sum of all Events (total tons)	8.0	40.9	7.1	0.7	-	-	-	-

4.4 Comparison of Annual Emissions by Operating Scenario and Vendor

> The following represents the annual emissions by operating scenario:

1) Profile 1 calculates the annual emissions using 8,760 hours at the highest hourly emissions rate at the average ambient temperature. In every case, DBs will not be necessary to generate the rated output.
2) Profile 2A calculates the annual emissions with 2,000 hr/yr of operation at 15°F, 4,760 hr/yr at 57°F, and 2,000 hr/yr at 90°F. The DBs and EC only kick in during the summer months. Although it artificially elevates the potential emission rate, for simplicity and conservatism, the total hours do not subtract periods of non-operation between a shutdown and a startup, nor do the total hours exclude the total time of GT operation during the events.
3) Profile 2B is the same as 2A except 127 hours of time for SUSD events is subtracted. Again, this case does not subtract periods of non-operation between a shutdown and a startup. Where, 127 hrs = (5 C-SU events * average of 40 & 70 min C-SU + 45 W-SU events * average of 30 & 60 min W-SU + 100 H-SU events * average of 21 & 35 min H-SU + 150 SD events * average of 12 & 21 min SD) * 60 mn/hr
4) Profile 3 is the maximum hourly emissions rate for any case multiplied by 8,760 hr/yr.

Emissions Profile	**Underlying Heat Input** (MMBtu/hr)	**NO_X** (tpy)	**CO** (tpy)	**VOC** (tpy)	**Total PM** (tpy)	**SO_2** (tpy)	**H_2SO_4** (tpy)	**NH_3** (tpy)	**CO_2** (tpy)
Profile 1: 8,760 hr/yr at 57 °F									
Vendor A (GT only)	4,124	131.4	80.2	22.8	78.4	30.7	20.6	121.8	2,352,060
Vendor B (GT only)	3,858	135.8	83.2	23.7	88.0				
Vendor C (GT only)	3,751	126.1	76.7	21.9	61.8			116.5	
Profile 2A: 2,000 hr/yr at 15 °F, **4,760** hr/yr at 57 °F, and 2,000 hr/yr at 90 °F									
Vendor A (GT + EC + DB)	**4,157**	132.6	80.8	28.4	80.0	**30.9**	**21.1**	**122.8**	**2,373,060**
Vendor B (GT + EC + DB)	3,850	**136.8**	**83.2**	**29.1**	**91.0**				
Vendor C (GT + EC + DB)	3,817	128.2	78.0	27.5	64.9			118.6	
Profile 2B: 2,000 hr/yr at 15 °F, **4,633** hr/yr at 57 °F, and 2,000 hr/yr at 90 °F									
Vendor A (GT + EC + DB)	4,097	130.7	79.6	28.0	78.9	30.4	20.8	121.0	2,338,961
Vendor B (GT + EC + DB)	3,794	134.8	82.0	28.7	89.8				
Vendor C (GT + EC + DB)	3,762	126.4	76.8	27.2	64.0			116.9	
Profile 3: 8,760 hr/yr at maximum hourly emissions for all operating scenarios									
Vendor A (GT + EC + DB)	4,216	134.5	81.9	46.9	86.3	31.1	22.3	124.4	2,404,620
Vendor B (GT + EC + DB)	3,854	140.2	83.2	47.7	102.1				
Vendor C (GT + EC + DB)	3,942	129.6	78.8	45.1	71.8			120.0	

Sample Calculations:
For Profile 1, Vendor A: NOx (tpy) = 30.0 lb/hr (for 57F, Case 10) x 8,760 hr/yr / 2,000 lb/ton = 131.4 tpy
For Profile 2A, Vendor B: NOx (tpy) = (31.0 lb/hr @15F x 2,000 hr/yr + 31.0 lb/hr @57F x 4,760 hr/yr + 32.0 lb/hr @90F x 2,000 hr/yr) / 2,000 lb/ton = 136.8 tpy

4.5 Defined PTE on a Seasonal Basis Determined Using Max Hourly Emission Rates by Vendor

> In reviewing the calculated annual emissions for the worst case operating scenarios presented in Section 4.4, LG&E has chosen to represent the potential emissions for the GT/DB based on Profile 2A. Profile 3 is not used because it is not practically realistic and could never occur in practice. While Profile 2A is also conservative, in that it does not subtract for SUSD hours (which is done in Profile 2B), the differences are not significant. Profile 2A, which considers the differences for cold and hot seasons, also predicts slightly higher potential emissions than the baseload case at the average ambient temperature. Thus, it is conservative but reasonable to use emissions for Profile 2A to define the PTE.

Selected Emissions Profile	NO_X (tpy)	CO (tpy)	VOC (tpy)	Total PM (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	NH_3 (tpy)	CO_2 (tpy)
Profile 1: 8,760 hr/yr at 57 °F								
Maximum by Vendor (tpy)	135.8	83.2	23.7	88.0	30.7	20.6	121.8	2,352,060
Profile 2A: 2,000 hr/yr at 15 °F, 4,760 hr/yr at 57 °F, and 2,000 hr/yr at 90 °F								
Maximum by Vendor (tpy)	136.8	83.2	29.1	91.0	30.9	21.1	122.8	2,373,060
Worst case GT PTE (Profile 2A)								
Maximum by Vendor (tpy) of Profile 1 or 2A	**136.8**	**83.2**	**29.1**	**91.0**	**30.9**	**21.1**	**122.8**	**2,373,060**
Maximum by Pollutant from SUSD Events (tpy)	**16.7**	**41.8**	**16.5**	**1.8**	0	0	0	0

4.6 Derivation of Emission Factors Based on Hourly Average Emission Rate

> Based on the defined PTE values (tpy), the equivalent hourly average emission rate (lb/hr) can be calculated. An emission factor in terms of lb/MMBtu can then be calculated based on the vendor-provided heat input associated with the case for which the PTE value is derived. See Section 4.4, which provides the underlying heat input rate.

> Emission factors in terms of lb/MMscf of gas fired are calculated based on the nominal average heating value of natural gas received at the Mill Creek Generating Station of 1,059 Btu/scf.

Selected Emissions Profile	NO_X	CO	VOC	Total PM	SO_2	H_2SO_4	NH_3	CO_2
Steady-State Stack Exhaust Emissions (lb/hr)								
Equivalent hourly emissions rate (Annual emissions for 2A in tpy x 2000 lb/ton / 8,760 hours)	31.23	19.00	6.63	20.78	7.05	4.81	28.03	541,795
Heat Input (MMBtu/hr, HHV)								
Weighted vendor-provided heat inputs (HHV) (highest is 4,157 MMBtu/hr for Vendor A)	3,850	3,850	3,850	3,850	**4,157**	**4,157**	**4,157**	**4,157**
Natural Gas Fuel Consumption (MMscf/hr)								
Steady State = Heat Input (MMBtu/yr, HHV) / NG HHV (Btu/scf) / 8,760 hr/yr	3.636	3.636	3.636	3.636	**3.925**	**3.925**	**3.925**	**3.925**
Steady-State Stack Emission Factor (lb/MMBtu, HHV)								
Emission factor associated with gas combustion during steady-state operation of GT + DB	**0.00811**	**0.00493**	**0.00172**	**0.00540**	0.00169	0.00116	**0.00674**	**130.34**
Steady-State Emission Factor (lb/MMscf, HHV)								
Emission factor converted to lb/MMscf based on average gas HV of 1,059 Btu/scf	**8.589**	**5.226**	**1.824**	**5.717**	1.795	1.226	**7.141**	**138,031**

Sample Calculations:
Steady-State Stack Exhaust Emissions: NOx (lb/hr) = 136.8 tpy x 2,000 lb/ton / 8,760 hr/yr = 31.23 lb/hr
Maximum Natural Gas Fuel Consumption = 4,157 MMBtu/hr (maximum for any pollutant) / 1,059 MMBtu/MMscf = 3.925 MMscf/hr
NOx Emission Factor (lb/MMBtu) = 31.23 lb/hr / 3,850 MMBtu/hr = 0.00811 lb/Mmbtu
NOx Emission Factor (lb/MMscf) = 31.23 lb/hr / 3.636 MMscf/hr = 8.589 lb/MMscf

5. Unit 5 Gas Turbine with HRSG/Duct Burners - Emission Calculations

> Emission factors and control efficiencies for the pollutants represented on the forms for the new GT/DB along with calculated potential emissions are documented in this section.

5.1 Description and Nomenclature

> The new emission unit identification and associated process IDs proposed to be assigned within the State and Local Emissions Inventory System (SLEIS) for the GT/DB are shown below. Both the GT and DB fire natural gas solely and Process ID 1 includes the natural gas fired in the GT and DB because both are exhausted through the same add-on control devices before exiting the stack. Process IDs 2 through 5 encompass possible startup and shutdown operating events, consistent with conventional approaches for representing emissions from combustion turbines.

GT/DB Emission Unit and Emission Point IDs and Descriptions	SLEIS Process ID#
U23 - EGU Unit 5 Gas Turbine with HRSG	
E49a - Natural Gas Firing in GT & DB	1
E49b - Cold Startup Events	2
E49c - Warm Startup Events	3
E49d - Hot Startup Events	4
E49e - Shutdown Events	5

5.2 Capacity and Fuel Information for E49a - Natural Gas Firing in GT & DB

> The following provides the capacity information for the GT/DB, as well as other relevant information used in the emissions estimates.

Natural Gas Higher Heating Value (HHV) at MC	1,059	Btu/scf	Average for Mill Creek Generating Station Inlet Gas
Natural Gas HHV used for AP-42 1.4 & 3-1	1,020	Btu/scf	
Maximum operating hours/yr used in permitting	8,760	hr/yr	LG&E did not take any reductions for time between events.
Total hours estimate for summer season	2,000	hr/yr	
Total hours estimate for fall and spring	4,760	hr/yr	
Total hours estimate for winter season	2,000	hr/yr	
Maximum operating hours/yr accounting for SUSD events	*5,314*	*hr/yr*	*Although not used in calculations, this is the actual estimate of operating hours IF LG&E excluded time for every SUSD event and time in between events*
Maximum Short-term Heat Input Capacity (for information only; not used in the calculations)	*4,216*	*MMBtu/hr*	*Max of three vendors out of all cases (Vendor A, Case 1 = GT only at -18°F and 100% of baseload)*
Maximum Short-term Fuel Consumption (for information only; not used in the calculations)	*3.981*	*MMscf/hr*	*= 4,216 MMBtu/hr / 1,059 Btu/scf*
Maximum Simulated Heat Input Capacity Used for Emission Calculations	**4,157**	MMBtu/hr	Weighted vendor-provided heat inputs (HHV) (highest is 4,157 MMBtu/hr for Vendor A), see Section 4.6.
Maximum Simulated Fuel Consumption	3.925	MMscf/hr	= 4,157 MMBtu/hr / 1,059 Btu/scf
Maximum Simulated Fuel Consumption	34,385	MMscf/yr	= 8,760 hr/yr * 3.925 MMscf/hr
SCC Code:	20100201	Electric Generation (2-01), Turbine (2-01-002-01)	
SCC Units:		Million Cubic Feet Natural Gas Burned (MMscf)	

5.3 Derivation and Documentation of Steady-State Operation Emission Factors

5.3.1 NSR-Regulated Pollutants

> Controlled emission factors (EFs) for all NSR-regulated pollutants have been calculated as described in Section 4 for the worst-case annual operating profile out of the four scenarios described therein. Any deviations from the vendor estimates are noted below. Lead emissions are addressed in the HAP subsection below.

NO_X

Concentration in stack exhaust after SCR	2	ppmvd @ 15% O2	LG&E's vendor guarantee requirement for NGCC
Controlled Emission Factor	**8.589**	lb/MMscf	See Section 4.6 for derivation
Controlled Emission Rate	33.71	lb/hr	= 8.589 lb/MMscf x 3.925 MMscf/hr
Control Efficiency (**not guaranteed**)	90	%	Nominal value for a SCR selected for purposes of defining an uncontrolled emission factor. Ranges between 75% and 91% depending on available nitrogen content and GT combustor design/operation.
Uncontrolled Emission Factor	85.892	lb/MMscf	= 8.589 lb/MMscf / (100% - 90%)

CO

Concentration in stack exhaust after oxidation catalyst	2	ppmvd @ 15% O2	LG&E's vendor guarantee requirement for GT
Controlled Emission Factor	**5.226**	lb/MMscf	See Section 4.6 for derivation
Controlled Emission Rate	20.51	lb/hr	= 5.226 lb/MMscf x 3.925 MMscf/hr
Control Efficiency (**not guaranteed**)	90	%	Nominal value for an oxidation catalyst
Uncontrolled Emission Factor	52.259	lb/MMscf	= 5.226 lb/MMscf / (100% - 90%)

VOC

Concentration in Stack Exhaust	1.23	ppmvd @ 15% O2	LG&E's vendor guarantee requirement for GT
Controlled Emission Factor	**1.824**	lb/MMscf	See Section 4.6 for derivation
Controlled Emission Rate	7.16	lb/hr	= 1.824 lb/MMscf x 3.925 MMscf/hr
Control Efficiency (**not guaranteed**)	50	%	Based on expected VOM control efficiency from catalytic oxidation.
Uncontrolled Emission Factor	3.649	lb/MMscf	= 1.824 lb/MMscf / (100% - 50%)

SO_2

> All vendors were told that the pipeline tariff is based on a sulfur content on 0.5 gr/100 scf (Cscf), and the highest sulfur measured in the last 4 years was 0.019 gr/Cscf. The following estimate is based solely on a maximum sulfur input of 0.5 gr/Cscf and 100% conversion from S to SO_2. In reality, the SO_2 should be reduced by the amount of SO_2 converted to SO_3, which can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. For simplicity, the following methodology does not account for these further reductions and thus the emission estimates are conservative.

Max sulfur content for pipeline gas	0.5	lb/Cscf	
Max actual sulfur content for pipeline gas in last 4 yrs	*0.019*	*lb/Cscf*	*Cited for informational purposes only.*
Molecular Weight of S	32.07	lb/lbmol	
Molecular Weight of SO2	64.07	lb/lbmol	
Uncontrolled Emission Rate	5.60	lb/hr	= 0.5 lb/Cscf x 10,000 Cscf/MMscf / 7,000 gr/lb / 1,059 x 4,157 MMBtu/hr x 64.07 lb /lbmol SO2 / 32.07 lb/lbmol S x 1 lbmol SO2/1 lbmol S x 100%
Uncontrolled Emission Factor	1.427	lb/MMscf	= 5.60 lb/hr / 3.925 MMscf/hr
Uncontrolled En	0.0013	lb/MMBtu	= 5.60 lb/hr / 4,157 MMBtu/hr

H_2SO_4

> Within the combustion process, SO_2 can be further oxidized into SO_3, which then can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. This conversion is influenced by the sulfur content in the fuel, ambient temperature/relative humidity, evaporative cooling operation, duct burner operation, oxidation over the oxidation catalyst, oxidation within the SCR, available moisture, ammonia slip concentration, acid dew point, etc. The estimates below are based on the following citation, "Pages 6-4 & 6-5 of Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update. EPRI, Palo Alto, CA: 2018. 3002012398", where the total conversion assumes 10% conversion for GT/DB + 3% for SCR + 10% for oxidation catalyst.

Molecular Weight of SO3	80.06	lb/lbmol	
Estimated SO2 to SO3 Conversation Rate	23%	10% conversion in GT/DB + 3% for SCR + 10% conversion across catalyst	
Estimated SO3 to H2SO4 Conversion Rate	100%	Conservative assumption	
Molecular Weight of H2SO4	98.08	lb/lbmol	
Uncontrolled Emission Rate of H2SO4	1.97	lb/hr	= 5.60 lb/hr SO2 * 23% SO2 to SO3 * 80.06 lb/lbmol SO3 / 64.07 lb/lbmol SO2 * 1 lbmole SO3 / 1 lbmole SO2 * 100% SO3 to H2SO4 * 98.08 lb/lbmol H2SO4 / 80.06 lb/lbmol SO3 * 1 lbmol H2SO4 / 1 lbmol SO3
Uncontrolled Emission Factor of H2SO4	0.503	lb/MMscf	= 1.97 lb/hr / 3.925 MMscf/hr

$PM/PM_{10}/PM_{2.5}$

> Steady-state generation of PM should be negligible from this NGCC system. For example, one prospective GT/DB vendor stated the following in their documentation, "PM-10 emissions from natural gas combustion are essentially zero (no emissions from the combustion process itself). The reported levels in the gathered data are due to non-combustion factors, which include test sampling and construction debris." When LG&E asked each vendor to provide PM estimates, all vendors provided overly conservative estimates of PM (not guarantees). Given the presence of the oxidation catalyst system, formation of condensable PM (CPM) and sub-micron filterable PM is a possibility under certain conditions. One pathway is the sulfate formation from H2SO4, (NH4)2SO4, and/or (NH4)HSO4, as well as the nitrate formation in the form of NH4NO3. However, the PM emissions from these pathways are still expected to be low. Regardless, given uncertainties, LG&E conservatively used the information provided by the vendors for defining PM emissions. In all cases, all PM can be assumed to be less than 2.5 μm in mean diameter (i.e., PM = PM10 = PM2.5).

Uncontrolled Emission Factor	5.717	lb/MMscf	See Section 4.6 for derivation
Uncontrolled Emission Factor	0.0054	lb/MMBtu	= 5.717 lb/MMscf / 1,059 Btu/scf
Uncontrolled Emission Rate	22.44	lb/hr	= 5.717 lb/MMscf x 3.925 MMscf/hr

Greenhouse Gases

> Emission factors for CO2 are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Table C-1). AP-42 emission factors in Section 3.1 have been used for the CH4 and N2O emission factors.

> The global warming multiplying factors for CH4 and N2O are those specified in 40 CFR 98 Subpart A. These are used to calculate the overall CO2e emissions.

CO_2

Uncontrolled Emission Factor	116.98	lb/MMBtu	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	123,879	lb/MMscf	= 116.98 lb/MMBtu * 1,059 MMBtu/MMscf
Uncontrolled Emission Rate	486,246	lb/hr	= 123,879 lb/MMscf x 3.925 MMscf/hr

CH_4

Uncontrolled Emission Factor	0.0086	lb/MMBtu	AP-42 Section 3.1 Stationary Gas Turbines, Table 3.1-2a
	8.772	lb/MMscf	= 0.0086 lb/MMBtu x 1,020 MMBtu/MMscf per AP-42

N_2O

Uncontrolled Emission Factor	0.0030	lb/MMBtu	AP-42 Section 3.1 Stationary Gas Turbines, Table 3.1-2a
	3.060	lb/MMscf	= 0.0030 lb/MMBtu x 1,020 MMBtu/MMscf per AP-42

CO_2e

Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.

CO2	1
CH4	25
N2O	298

Uncontrolled Emission Factor	125,010	lb/MMscf	(CO2 EF) + (CH4 EF x CH4 GWP) + (N2O EF x N2O GWP)

5.3.2 Ammonia (from Ammonia Slip in SCR)

NH_3

Concentration in stack exhaust	5 ppmvd @ 15% O2	LG&E's vendor guarantee requirement for NGCC
Uncontrolled Emission Factor	7.141 lb/MMscf	See Section 4.6 for derivation
Uncontrolled Emission Rate	28.03 lb/hr	= 7.141 lb/MMscf x 3.925 MMscf/hr

5.3.3 Hazardous Air Pollutants for GT

Formaldehyde

Concentration in stack exhaust	0.091 ppmvd @ 15% O2	LG&E's vendor guarantee requirement per 40 CFR §63.6100 and Table 1 of NESHAP YYYY
Molecular weight of HCHO	30.031 lb/lbmol	
Oxygen based F-Factor	8,638 dscf/MMBtu	RM Method 19 determination of Fd factor for natural gas combustion can use a default value of 8,710, or use equations 19-13 through 19.15. LG&E chose to use Vendor A's derived Fd at ~8638 dscf/MMBtu.
Uncontrolled Emission Rate	0.90 lb/hr	= 1.0 atm STD x 30.031 lb/lbmol HCHO / 0.7302 ft3-atm/lbmol-°R / 527.67°R STD x 0.091 ppmvd @ 15% O2 /1E6 x 8,638.0 dscf/MMBtu x (20.9/(20.9-15) x 4,157 MMBtu/hr
Uncontrolled Emission Factor	0.230 lb/MMscf	= 0.90 lb/hr / 3.925 MMscf/hr

> Other than for formaldehyde (described above), emission factors for organic and metallic HAP emissions from natural gas-fired turbines published in AP-42, Section 3.1 are used to estimate potential emissions.

Pollutant	CAS No.	GT Uncontrld EF (lb/MMBtu)	GT Uncontrld EF (lb/MMscf)	Oxidation Catalyst Control Efficiency[4] (%)	GT After Oxidation Catalyst EF (lb/MMBtu)	GT After Oxidation Catalyst EF (lb/MMscf)	Basis	Note
1,3-Butadiene	106-99-0	4.3E-07	4.386E-04	50%	2.2E-07	2.2E-04	AP-42 Table 3.1	2
Acetaldehyde	75-07-0	3.5E-04	3.590E-01	50%	1.8E-04	1.8E-01	AP-42 Table 3.1 & 3-4 of BID	1, 2
Acrolein	107-02-8	6.4E-06	6.528E-03	43%	3.6E-06	3.7E-03	AP-42 Table 3.1 & 3-4 of BID	1
Benzene	71-43-2	1.2E-05	1.224E-02	73%	3.3E-06	3.3E-03	AP-42 Table 3.1 & 3-4 of BID	1
Ethylbenzene	100-41-4	3.2E-05	3.264E-02	50%	1.6E-05	1.6E-02	AP-42 Table 3.1	2
Formaldehyde	50-00-0	7.1E-04	7.242E-01	68%	2.3E-04	2.3E-01	LG&E Requirement	2, 3
Naphthalene	91-20-3	1.3E-06	1.326E-03	50%	6.5E-07	6.6E-04	AP-42 Table 3.1	2
PAH		2.2E-06	2.244E-03	50%	1.1E-06	1.1E-03	AP-42 Table 3.1	2
Propylene Oxide	75-56-9	2.9E-05	2.958E-02	50%	1.5E-05	1.5E-02	AP-42 Table 3.1	2
Toluene	108-88-3	1.3E-04	1.326E-01	50%	6.5E-05	6.6E-02	AP-42 Table 3.1	2
Xylenes	1330-20-7	6.4E-05	6.528E-02	50%	3.2E-05	3.3E-02	AP-42 Table 3.1	2

1. Controlled emission factors (Oxidation Catalyst) for Acetaldehyde, Acrolein and Benzene are obtained from U.S. EPA's Emission Factor Documentation for AP-42 Section 3.1 Stationary Gas Turbines.
2. Emission factors for 1,3- Butadiene, Acetaldehyde, Ethylbenzene, Propylene Oxide, Toluene, Xylenes, Naphthalene and PAH are obtained from AP-42 Chapter 3.1, Table 3.1-3 (Stationary Gas Turbines, April, 2000). A control efficiency of 50% was applied to these uncontrolled emission factors based on expected VOM control efficiency from catalytic oxidation.
3. See LG&E requirement above for formaldehyde that sets the GT post-oxidation catalyst EF.
4. The control efficiencies are estimates and should not be construed as guarantees.

5.3.4 Hazardous Air Pollutants for DB

> Emission factors from DBs are obtained from AP-42, Chapter 1.4, Table 1.4-2, 1.4-3, 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Polycyclic aromatic hydrocarbons were omitted from the DB emission factor list since they are accounted for with the GT.

Pollutant	CAS No.	DB Uncontrld EF (lb/MMBtu)	DB Uncontrld EF (lb/MMscf)	Oxidation Catalyst Control Efficiency[5] (%)	DB After Oxidation Catalyst EF (lb/MMBtu)	DB After Oxidation Catalyst EF (lb/MMscf)	Basis	Note
Benzene	71-43-2	2.1E-06	2.1E-03	50%	1.0E-06	1.1E-03	AP-42 Table 1.4-3	1, 2, 4
Dichlorobenzene	25321-22-6	1.2E-06	1.2E-03	50%	5.9E-07	6.0E-04	AP-42 Table 1.4-3	1, 2
Formaldehyde	50-00-0							3
Naphthalene	91-20-3	6.0E-07	6.1E-04	50%	3.0E-07	3.1E-04	AP-42 Table 1.4-3	1, 2, 4
Hexane	110-54-3	1.8E-03	1.8E+00	50%	8.8E-04	9.0E-01	AP-42 Table 1.4-3	1, 2
Toluene	108-88-3	3.3E-06	3.4E-03	50%	1.7E-06	1.7E-03	AP-42 Table 1.4-3	1, 2, 4
Arsenic	7440-38-2	2.0E-07	2.0E-04		2.0E-07	2.0E-04	AP-42 Table 1.4-4	1
Beryllium	7440-41-7	1.2E-08	1.2E-05		1.2E-08	1.2E-05	AP-42 Table 1.4-4	1
Cadmium	7440-43-9	1.1E-06	1.1E-03		1.1E-06	1.1E-03	AP-42 Table 1.4-4	1
Chromium	7440-47-3	1.4E-06	1.4E-03		1.4E-06	1.4E-03	AP-42 Table 1.4-4	1
Cobalt	7440-48-4	8.2E-08	8.4E-05		8.2E-08	8.4E-05	AP-42 Table 1.4-4	1
Lead	7439-92-1	4.9E-07	5.0E-04		4.9E-07	5.0E-04	AP-42 Table 1.4-4	1
Manganese	7439-96-5	3.7E-07	3.8E-04		3.7E-07	3.8E-04	AP-42 Table 1.4-4	1
Mercury	7439-97-6	2.5E-07	2.6E-04		2.5E-07	2.6E-04	AP-42 Table 1.4-4	1
Nickel	7440-02-0	2.1E-06	2.1E-03		2.1E-06	2.1E-03	AP-42 Table 1.4-4	1
Selenium	7782-49-2	2.4E-08	2.4E-05		2.4E-08	2.4E-05	AP-42 Table 1.4-4	1

1. Emission factors are obtained from AP-42, Chapter 1.4, Table 1.4-2, 1.4-3, 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998).
2. A control efficiency of 50% was applied to these uncontrolled emission factors based on expected VOM control efficiency from catalytic oxidation.
3. See LG&E requirement for formaldehyde produced in the GT, as it applies to the entire NGCC.
4. Not used in PTE analysis because GT EF is higher than DB.
5. The control efficiencies are estimates and should not be construed as guarantees.

5.4 NGCC Potential Emissions Summary - Steady State Operations

> The following represents the potential emissions assuming the GT+DB combust natural gas at 4,157 MMBtu/hr heat input for 8,760 hours per year, which is not possible given the range of shutdowns and startups that can occur during a particular year. However, to be conservative and to avoid any restriction on the hours of "normal" or steady state operations, this approach is used. Also, the size of the NG-fired DBs are ≤ 296 MMBtu/hr, yet if there was an EF that had a greater lb/MMscf for DB operation, it was used in the PTE, which also adds conservatism to the estimated PTE values.

> The EFs used for HAPs represent the higher of GT or DB emission factors, even though it is unrealistic for a DB to be operational outside of brief summertime events. Thus, the HAP potential emission values are very conservative.

Process ID 1: Steady-State Operation with or without DBs

	Uncontrolled EF (lb/MMscf)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	~Control Efficiency	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Regulated Pollutants							
NOX	85.892	LG&E Requirement	337.1	1476.7	90%	33.7	147.7
CO	52.259	LG&E Requirement	205.1	898.4	90%	20.5	89.8
VOC	3.649	LG&E Requirement	14.32	62.7	50%	7.16	31.4
PM	5.717	Vendor Estimate	22.4	98.3		22.4	98.3
PM10	5.717	Vendor Estimate	22.4	98.3		22.4	98.3
PM2.5	5.717	Vendor Estimate	22.4	98.3		22.4	98.3
SO2	1.427	Pipeline spec conversion	5.60	24.5		5.60	24.5
H2SO4	0.503	Pipeline spec conversion	1.97	8.6		1.97	8.6
NH3	7.141	LG&E Requirement	28.0	122.8		28.0	122.8
CO2e	125,010	40 CFR 98, Table C-1	490,686	2,149,207		490,686	2,149,207

	CAS No.	Uncontrolled EF (lb/MMscf)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	~Control Efficiency	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Hazardous Air Pollutants								
1,3-Butadiene	106-99-0	4.39E-04	AP-42 Table 3.1	0.002	0.008	50%	0.001	0.004
Acetaldehyde	75-07-0	3.59E-01	AP-42 Table 3.1 & 3-4 of BID	1.409	6.173	50%	0.705	3.086
Acrolein	107-02-8	6.53E-03	AP-42 Table 3.1 & 3-4 of BID	0.026	0.112	43%	0.014	0.063
Benzene	71-43-2	1.22E-02	AP-42 Table 3.1 & 3-4 of BID	0.048	0.210	73%	0.013	0.057
Dichlorobenzene	25321-22-6	1.20E-03	AP-42 Table 1.4-3	0.005	0.021	50%	0.002	0.010
Ethylbenzene	100-41-4	3.26E-02	AP-42 Table 3.1	0.128	0.561	50%	0.064	0.281
Formaldehyde	50-00-0	7.24E-01	LG&E Requirement	2.843	12.451	68%	0.902	3.951
Hexane	110-54-3	1.80E+00	AP-42 Table 1.4-3	7.065	30.946	50%	3.533	15.473
Naphthalene	91-20-3	1.33E-03	AP-42 Table 3.1	0.005	0.023	50%	0.003	0.011
Propylene Oxide	75-56-9	2.96E-02	AP-42 Table 3.1	0.116	0.509	50%	0.058	0.254
Toluene	108-88-3	1.33E-01	AP-42 Table 3.1	0.520	2.28	50%	0.260	1.14
Xylenes	1330-20-7	6.53E-02	AP-42 Table 3.1	0.256	1.12	50%	0.128	0.56
Arsenic	7440-38-2	2.00E-04	AP-42 Table 1.4-4	7.85E-04	3.44E-03	0%	7.85E-04	3.44E-03
Beryllium	7440-41-7	1.20E-05	AP-42 Table 1.4-4	4.71E-05	2.06E-04	0%	4.71E-05	2.06E-04
Cadmium	7440-43-9	1.10E-03	AP-42 Table 1.4-4	4.32E-03	1.89E-02	0%	4.32E-03	1.89E-02
Chromium	7440-47-3	1.40E-03	AP-42 Table 1.4-4	5.50E-03	2.41E-02	0%	5.50E-03	2.41E-02
Cobalt	7440-48-4	8.40E-05	AP-42 Table 1.4-4	3.30E-04	1.44E-03	0%	3.30E-04	1.44E-03
Lead	7439-92-1	5.00E-04	AP-42 Table 1.4-4	1.96E-03	8.60E-03	0%	1.96E-03	8.60E-03
Manganese	7439-96-5	3.80E-04	AP-42 Table 1.4-4	1.49E-03	6.53E-03	0%	1.49E-03	6.53E-03
Mercury	7439-97-6	2.60E-04	AP-42 Table 1.4-4	1.02E-03	4.47E-03	0%	1.02E-03	4.47E-03
Nickel	7440-02-0	2.10E-03	AP-42 Table 1.4-4	8.24E-03	3.61E-02	0%	8.24E-03	3.61E-02
Selenium	7782-49-2	2.40E-05	AP-42 Table 1.4-4	9.42E-05	4.13E-04	0%	9.42E-05	4.13E-04
Total HAP		3.171		12.447	54.519		5.707	24.997

5.5 Capacity and Underlying Assumptions for E49b thru E49e Cold, Warm, Hot, and Shutdown Events

> The following are estimates provided by each vendor:

			Time in between event and SD
> Cold starts are preceded by over 72 hours of shutdown.			
Maximum Annual Cold Start Events	5 events/yr	40-70 min/C-SU	>72 hr of SD
> Warm start cool down duration ranges from >8 to <72 hours after shutdown. Assume 48 hours.			
Maximum Annual Warm Start Events	45 events/yr	30-60 min/W-SU	8-72 hr of SD
> Hot starts are defined as taking place within 8 hours of the previous shutdown.			
Maximum Annual Hot Start Events	100 events/yr	21-35 min/H-SU	0-8 hr of SD
> Shutdowns will occur for 12-21 min and the total number of events is the sum of all cold, warm, and hot startups.			
Maximum Annual Shutdown Events	150 events/yr	12-21 min/SD	

> There is not an SCC code for turbine SUSD events; therefore, LG&E used the generic not classified category for industrial processes on an "each" basis.

SCC Code: 39999993 Misc. Industrial Processes (3-99), Others Not Classified (3-99-999-93)
SCC Units: Each Event (i.e., "lb per event")

5.5.1 Startup and Shutdown Event Emission Factors

> The EFs presented below for emissions of NSR-regulated pollutants from startup and shutdown events are based on the highest vendor-provided lb/event.

Event Type	NO_X EF (lb/event)	CO EF (lb/event)	VOC EF (lb/event)	$PM/PM_{10}/PM_{2.5}$ EF (lb/event)
Cold Start	420	758	135	32
Warm Start	260	476	121	27
Hot Start	135	303	91	15
Shutdown	78	244	118	5

5.6 GT Cold, Warm, & Hot Startups, and Shutdown Potential Emissions Summary

> The following potential emissions represent the maximum pounds per SUSD event by pollutant.

Pollutant	Uncontrolled EF (lb/event)	Uncontrolled EF Basis	Uncontrolled Emissions (lb/yr)	Uncontrolled Emissions (tpy)	Control Efficiency	Controlled Emissions (lb/yr)	Controlled Emissions (tpy)
Process ID 2: Cold Startups							
NOX	420	Vendor A Max	2,100	1.05	N/A	2,100	1.05
CO	758	Vendor C Max	3,790	1.90	N/A	3,790	1.90
VOC	135	Vendor B Max	675	0.34	N/A	675	0.34
PM	32	Vendor A Max	160	0.08	N/A	160	0.08
PM10	32	Vendor A Max	160	0.08	N/A	160	0.08
PM2.5	32	Vendor A Max	160	0.08	N/A	160	0.08
Process ID 3: Warm Startups							
NOX	260	Vendor A Max	11,700	5.85	N/A	11,700	5.85
CO	476	Vendor B Max	21,420	10.7	N/A	21,420	10.7
VOC	121	Vendor B Max	5,445	2.72	N/A	5,445	2.72
PM	27	Vendor A Max	1,215	0.61	N/A	1,215	0.61
PM10	27	Vendor A Max	1,215	0.61	N/A	1,215	0.61
PM2.5	27	Vendor A Max	1,215	0.61	N/A	1,215	0.61
Process ID 4: Hot Startups							
NOX	135	Vendor A Max	13,500	6.75	N/A	13,500	6.75
CO	303	Vendor B Max	30,300	15.2	N/A	30,300	15.2
VOC	91	Vendor B Max	9,100	4.55	N/A	9,100	4.55
PM	15	Vendor B Max	1,500	0.75	N/A	1,500	0.75
PM10	15	Vendor B Max	1,500	0.75	N/A	1,500	0.75
PM2.5	15	Vendor B Max	1,500	0.75	N/A	1,500	0.75
Process ID 5: Shutdowns							
NOX	78	Vendor B Max	11,700	5.85	N/A	11,700	5.85
CO	244	Vendor C Max	36,600	18.3	N/A	36,600	18.3
VOC	118	Vendor B Max	17,700	8.9	N/A	17,700	8.85
PM	5	Vendor B Max	750	0.38	N/A	750	0.38
PM10	5	Vendor B Max	750	0.38	N/A	750	0.38
PM2.5	5	Vendor B Max	750	0.38	N/A	750	0.38

5.7 NGCC Overall Combined PTE Summary - Steady State Operations + SUSD Events

> The table below summarizes the PTE from all Process IDs. The total emissions from the NGCC include 8,760 hours at "normal" or steady state operations plus (not minus) the total hours and emissions of SUSD events while the GT is emitting.

> The calculation of PTE is conservative since the hours in which SUSD events are occurring are not subtracted from the total steady state operational hours (8,760 hr/yr). In reality, based on the SUSD assumptions, there could be as much as 127 hours of SUSD conditions each year.

> Additionally, if the GT/DB experienced all 150 events, there would be no emissions for up to 3,447 hr/yr if one accounted for the downtime in-between SUSD events (i.e., 5 C-SU * 72 avg hrs down + 45 W-SU * 48 avg hrs down + 100 H-SU * 8 avg hrs down).

> Combined Process ID potential emissions are only shown for NOx, CO, VOC, and PM/PM10/PM2.5 since these are the only pollutants for which incremental emissions during SUSD events are quantified. Potential emissions for other pollutants and HAPs are as shown in Section 5.4.

Pollutant	PTE (tpy)
NOX	167.2
CO	135.9
VOC	47.8
PM	100.1
PM10	100.1
PM2.5	100.1

6. Auxiliary Steam Boiler - Emissions Calculations

> A new auxiliary steam boiler will be installed as part of the NGCC project. Potential emissions for the auxiliary steam boiler are documented in this section.

6.1 Auxiliary Boiler Nomenclature and Specifications

> Proposed nomenclature for the new Aux Boiler associated with the NGCC Plant:

Emission Unit:	**U24 - Auxiliary Steam Boiler**
Emission Point:	E50 - Natural Gas Combustion w/ LNB & FGR
Control Device:	-- - --
Stack ID:	S50

> LG&E plans to provision a NG-fired auxiliary boiler for the NGCC project. While construction of the GT/DB is targeted to commence in March 2024, because the construction timeline for the Aux Boiler is much shorter, it may not start construction until later in the construction phase. As such, the specific make and model for the Aux Boiler will not be known until farther on in the project development. However, LG&E plans to procure a boiler with a maximum heat input capacity of 99.9 MMBtu/hr or less and the boiler will be equipped with low-NOX burners with a flue gas recirculation system. For permitting purposes and to calculate potential emissions, this maximum heat input capacity is assumed.

SCC Code	10200602
SCC Description	External Combustion Boilers - Industrial (1-02) - Natural Gas (1-02-006) - 10-100 Million Btu/hr (1-02-006-02)
SCC Units	Million Cubic Feet Natural Gas Burned

> Although the Aux Boiler will only operate periodically to assist with warm or cold startups of the gas turbine (U23) and to provide freeze protection during winter downtime hours, potential emissions are calculated based on 8,760 hr/yr of operation for simplicity and conservatism.

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**99.9**	**MMBtu/hr**	
Gross Steam Generation	82,745	lb/hr	
Net Steam Generation	69,645	lb/hr	
NG Heating Value	1,059	Btu/scf	Average for Mill Creek Generating Station Inlet Gas
Max Gas Firing Rate at Average HHV	0.0943	MMscf/hr	99.9 MMBtu/hr / 1,059 MMBtu/MMscf = 0.0943 MMscf/hr
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	

6.2 Derivation and Documentation of Emission Factors

6.2.1 Constants and Conversion Factors

Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm x 0.7302 cf-atm/(lbmol-°R)
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO2	64.07	lb SO_2/lbmol	
Molecular Weight of H2SO4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for Mill Creek inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

6.2.2 Prospective Vendor Data

Pollutant	CAS #	Concentration (ppmv @ 3% O_2)	Concentration (ppmv @ 0% O_2)	Emission Factor Basis
NOx	na	30	35	LG&E requirement for boiler with Low NOx Burners (LNB) and Flue Gas Recirculation (FGR) firing at high fire (100% load); exhaust expressed at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)
CO	00630-08-0	50	58	LG&E requirement at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)

6.2.3 Regulated NSR Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NOx	10102-44-0	0.0364	38.557	LG&E requirement (Vendor Guarantee) 35 lbmol NO2/10^6 lbmol air x 46.01 lb NO2/lbmol / 385.5 scf/lbmol x 8,710 dscf/MMBtu x 1,059 MMBtu/MMscf = 38.557 lb/MMscf
CO	00630-08-0	0.0369	39.121	LG&E requirement (Vendor Guarantee) 58 lbmol CO/10^6 lbmol air x 28.01 lb CO/lbmol / 385.5 scf/lbmol x 8,710 dscf/MMBtu x 1,059 MMBtu/MMscf = 39.121 lb/MMscf
VOC	na	0.0054	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM/PM10/PM2.5-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Table 1.4-2 + EPA Speciate Database
PM/PM10/PM2.5 Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
SO2	07446-09-5	0.0013	1.427	0.5 gr/Ccf / 7,000 gr/lb x 64.07 lb SO2/lbmol / 32.07 lb S/lbmol x 10,000 Ccf/MMscf = 1.427 lb/MMscf
H2SO4	7664-93-9	1.03E-04	0.109	5% conversion of SO2 to SO3 and 100% conversion of SO3 to H2SO4 1.427 lb SO2/MMscf x 5% x 100% x 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol = 0.109 lb/MMscf
Lead		4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO2		116.98	123,879	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH4		0.0022	2.335	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N2O		0.0002	0.233	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO2e		117.10	124,007	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

6.2.4 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.8E+00
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.888

6.3 Aux Boiler Potential Emissions Summary

Pollutant	Emission Factor (lb/MMscf)	Emission Factor Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_X	38.557	LG&E Requirement	3.637	15.93
CO	39.121	LG&E Requirement	3.690	16.16
VOC	5.5	AP-42 Table 1.4-2	0.519	2.27
PM/PM10/PM2.5-Filt	1.9	AP-42 Table 1.4-2	0.179	0.79
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.148	0.65
PM/PM10/PM2.5 Total	3.47	AP-42 Table 1.4-2	0.327	1.43
SO2	1.43	Pipeline spec conversion	0.135	0.59
H2SO4	0.109	Pipeline spec conversion	0.010	0.05
Lead	0.0005	AP-42, Table 1.4-2	4.72E-05	2.07E-04
CO2e	124,007	40 CFR 98, Table C-1	11,698	51,238
Hazardous Air Pollutants	1.888	Sum of HAPs	0.178	0.78
Benzene	2.1E-03	AP-42, Table 1.4-3	1.98E-04	8.68E-04
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	1.13E-04	4.96E-04
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	7.08E-03	3.10E-02
Hexane	1.8E+00	AP-42, Table 1.4-3	0.170	0.744
Naphthalene	6.1E-04	AP-42, Table 1.4-3	5.75E-05	2.52E-04
Toluene	3.4E-03	AP-42, Table 1.4-3	3.21E-04	1.40E-03
Arsenic	2.0E-04	AP-42, Table 1.4-4	1.89E-05	8.26E-05
Cadmium	1.1E-03	AP-42, Table 1.4-4	1.04E-04	4.55E-04
Chromium	1.4E-03	AP-42, Table 1.4-4	1.32E-04	5.78E-04
Manganese	3.8E-04	AP-42, Table 1.4-4	3.58E-05	1.57E-04
Mercury	2.6E-04	AP-42, Table 1.4-4	2.45E-05	1.07E-04
Nickel	2.1E-03	AP-42, Table 1.4-4	1.98E-04	8.68E-04

Sample Calculations:

NOx (lb/hr) = 38.557 lb/MMscf x 0.0943 MMscf/hr = 3.637 lb/hr NOx

NOx (tpy) = 3.637 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 15.93 tpy NOx

7. Fuel Gas (Dewpoint) Preheater - Emissions Calculations

> A new fuel gas preheater will be installed as part of the NGCC project to provide supplemental heating when needed to the incoming natural gas feed stream. Potential emissions for the preheater are documented in this section.

7.1 Preheater Nomenclature and Specifications

> Proposed nomenclature for the new fuel gas (dewpoint) preheater associated with the NGCC Plant:

Emission Unit:	**U26 - Fuel Gas (Dewpoint) Heater**
Emission Point:	E52 - NG Fuel Combustion (15 MMBtu/hr)
Control Device:	-- - --
Stack ID:	S52

> LG&E plans to provision a natural-gas fired preheater for the NGCC project. The specific make and model are will not be known until farther along in the project development phase. However, the maximum heat input capacity will be 15 MMBtu/hr or less and the preheater will be equipped with LNBs or LNBs with FGR. For permitting purposes and to calculate potential emissions, this maximum heat input capacity is assumed.

SCC Code	39990003
SCC Description	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)
SCC Units	Million Cubic Feet Natural Gas Burned

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**15**	**MMBtu/hr**	
NG Heating Value	1,059	Btu/scf	Average for Mill Creek Generating Station Inlet Gas
Max Gas Firing Rate at Average HHV	0.0142	MMscf/hr	15 MMBtu/hr / 1,059 MMBtu/MMscf = 0.0142 MMscf/hr
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	

7.2 Derivation and Documentation of Emission Factors

7.2.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm x 0.7302 cf-atm/(lbmol-°R)
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO2	64.07	lb SO_2/lbmol	
Molecular Weight of H2SO4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for Mill Creek inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

7.2.2 Prospective Vendor Data

Pollutant	CAS #	Concentration (ppmv @ 3% O_2)	Concentration (ppmv @ 0% O_2)	Emission Factor Basis
NO_X	na	30	35	LG&E requirement for boiler at high fire (100% load); exhaust expressed at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)
CO	00630-08-0	101	118	LG&E requirement at 100% load at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)

7.2.3 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NOx	10102-44-0	0.0364	38.557	LG&E's Vendor requirement 35 lbmol NO2/10^6 lbmol air x 46.01 lb NO2/lbmol / 385.5 scf/lbmol x 8,710 dscf/MMBtu x 1,059 MMBtu/MMscf = 38.557 lb/MMscf
CO	00630-08-0	0.0746	79.025	LG&E's Vendor requirement 118 lbmol CO/10^6 lbmol air x 28.01 lb CO/lbmol / 385.5 scf/lbmol x 8,710 dscf/MMBtu x 1,059 MMBtu/MMscf = 79.025 lb/MMscf
VOC	na	0.005	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM/PM10/PM2.5-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Table 1.4-2 + EPA Speciate Database
PM/PM10/PM2.5 Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
SO2	07446-09-5	0.0013	1.427	0.5 gr/Ccf / 7,000 gr/lb x 64.07 lb SO2/lbmol / 32.07 lb S/lbmol x 10,000
H2SO4	7664-93-9	1.03E-04	0.109	5% conversion of SO2 to SO3 and 100% conversion of SO3 to H2SO4 1.427 lb SO2/MMscf x 5% x 100% x 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol = 0.109 lb/MMscf
Lead		4.72E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO2		116.98	123,879	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH4		0.0022	2.33	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N2O		0.0002	0.233	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO2e		117.10	124,007	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

7.2.4 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.8E+00
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.888

7.3 Preheater Potential Emissions Summary

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_X	38.557	LG&E Requirement	0.546	2.392
CO	79.025	LG&E Requirement	1.119	4.903
VOC	5.5	AP-42 Table 1.4-2	0.078	0.341
PM/PM10/PM2.5-Filt	1.9	AP-42 Table 1.4-2	0.027	0.118
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.022	0.097
PM/PM10/PM2.5 Total	3.47	AP-42 Table 1.4-2	0.049	0.215
SO2	1.43	Pipeline spec conversion	0.020	0.089
H2SO4	0.109	Pipeline spec conversion	1.55E-03	6.78E-03
Lead	0.0005	AP-42, Table 1.4-2	7.08E-06	3.10E-05
CO2e	124,007	40 CFR 98, Table C-1	1,756	7,693
Hazardous Air Pollutants	1.888	Sum of HAPs	0.027	0.117
Benzene	2.1E-03	AP-42, Table 1.4-3	2.97E-05	1.30E-04
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	1.70E-05	7.44E-05
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	1.06E-03	4.65E-03
Hexane	1.8E+00	AP-42, Table 1.4-3	2.55E-02	1.12E-01
Naphthalene	6.1E-04	AP-42, Table 1.4-3	8.64E-06	3.78E-05
Toluene	3.4E-03	AP-42, Table 1.4-3	4.82E-05	2.11E-04
Arsenic	2.0E-04	AP-42, Table 1.4-4	2.83E-06	1.24E-05
Cadmium	1.1E-03	AP-42, Table 1.4-4	1.56E-05	6.82E-05
Chromium	1.4E-03	AP-42, Table 1.4-4	1.98E-05	8.69E-05
Manganese	3.8E-04	AP-42, Table 1.4-4	5.38E-06	2.36E-05
Mercury	2.6E-04	AP-42, Table 1.4-4	3.68E-06	1.61E-05
Nickel	2.1E-03	AP-42, Table 1.4-4	2.97E-05	1.30E-04

Sample Calculations:

NOx (lb/hr) = 38.557 lb/MMscf x 0.0142 MMscf/hr = 0.546 lb/hr NOx

NOx (tpy) = 0.546 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 2.39 tpy NOx

8. Mechanical Draft Cooling Tower - Emissions Calculations

> The NGCC Plant will be served by one re-circulating counterflow wet linear mechanical draft cooling tower. Potential emissions for the cooling tower are documented in this section.

8.1 Cooling Tower Nomenclature and Specifications

> Proposed nomenclature for the new cooling tower associated with the NGCC plant:

Emission Unit	**IA5 - Other Insignificant Activities**
Emission Point	IE24 - Mechanical Draft Cooling Tower (8 Cells) for NGCC
Control Device	-- - --
Stack ID	Fugitive

SCC Code	38500101
SCC Description	Industrial Processes - Cooling Tower (3-85) - Process Cooling (3-85-001) - Mechanical Draft (3-85-001-01)
SCC Units	Million Gallons Cooling Water Throughput

8.2 Methodology for Defining Potential PM Emissions from Cooling Tower

8.2.1 PM Emission Factor

> As the water flows down through a cooling tower, the draft air picks up water droplets that can be emitted from the top of the tower (i.e., "drift loss"). Drift loss is minimized through the use of mist eliminators. Particulate matter emissions can result due to the presence of dissolved solids in the cooling tower water droplets that are released from the tower. As the cooling tower droplets disperse in the atmosphere, the liquid water evaporates, leaving behind solid particles in the form of particulate matter.

> Particulate matter emissions from cooling towers are estimated using the procedures of AP-42 Section 13.4 (1/1995 edition), in which PM emissions are estimated as a function of the tower flow capacity, drift loss, and total dissolved solids (TDS) in the cooling tower recirculating water.

> Cooling Tower Design Parameters:

Max Annual Operating Hours	8,760	hr/yr	
Circulating Water Flow Rate	95,000	gpm	
	5.7	MMgal/hr	95,000 gpm x 60 min/hr / 1E6 gal/MMgal = 5.7
Total Dissolved Solids (TDS) of Recirculating Water	990	ppm	
Drift Percentage for Cooling Tower Mist Eliminator	0.001	%	
Density of Circulating Water	8.34	lb/gal	

PM emission factor based on AP42 13.4 methodology:

PM Factor = 1.0E-05 gal drift/gal flow x 8.34 lb/gal x 990 ppm = $\boxed{0.0826 \text{ lb/MMgal}}$

8.2.2 PM10 and PM2.5 Emission Factors

> PM_{10} and $PM_{2.5}$ emission factors are derived from the PM emission factor calculated above using the methodology presented in "Calculating Realistic PM_{10} Emissions from Cooling Towers" by Joe Reisman and Gordon Frisbie, Environmental Progress, Volume 21, Issue 2 (April 20, 2004).

> The aerodynamic diameter of a particle resulting from drift was calculated over a target droplet size distribution presented in the table below, taken from the source cited above. By interpolating on the calculated aerodynamic particle diameter, the corresponding mass percentage smaller than $PM_{2.5}$ and PM_{10} can be derived.

Droplet Diameter Size[1] (µm)	EPRI % Mass Smaller[1] (%)	Droplet Volume (µm³)	Droplet Mass (µg)	Particle Mass (Solids) (µg)	Solid Particle Volume (µm³)	Solid Particle Diameter (µm)	Aerodyn. Particle Diameter (µm)
10	0	524	5.24E-04	5.18E-07	0.24	0.77	1.1
20	0.196	4,189	4.19E-03	4.15E-06	1.88	1.53	2.3
22.0	***0.202***	***5,571***	***5.57E-03***	5.52E-06	***2.51***	1.69	***2.5***
30	0.226	14,137	0.01	1.40E-05	6.36	2.30	3.4
40	0.514	33,510	0.03	3.32E-05	15.08	3.07	4.5
50	1.816	65,450	0.07	6.48E-05	29.45	3.83	5.7
60	5.702	113,097	0.11	1.12E-04	50.89	4.60	6.8
70	21.348	179,594	0.18	1.78E-04	80.82	5.36	8.0
88.0	***46.937***	***356,576***	***0.36***	3.53E-04	***160.46***	6.74	***10.0***
90	49.812	381,704	0.38	3.78E-04	171.77	6.90	10.2
110	70.509	696,910	0.70	6.90E-04	314	8.43	12.5
130	82.023	1,150,347	1.15	1.14E-03	518	9.96	14.8
150	88.012	1,767,146	1.77	1.75E-03	795	11.49	17.0
180	91.032	3,053,628	3.05	3.02E-03	1,374	13.79	20.5
210	92.468	4,849,048	4.85	4.80E-03	2,182	16.09	23.9
240	94.091	7,238,229	7.24	7.17E-03	3,257	18.39	27.3
270	94.689	10,305,995	10.31	1.02E-02	4,638	20.69	30.7
300	96.288	14,137,167	14.14	1.40E-02	6,362	22.99	34.1
350	97.011	22,449,298	22.45	2.22E-02	10,102	26.82	39.8
400	98.340	33,510,322	33.51	3.32E-02	15,080	30.65	45.5
450	99.071	47,712,938	47.71	4.72E-02	21,471	34.48	51.1
500	99.071	65,449,847	65.45	6.48E-02	29,452	38.32	56.8
600	100	113,097,336	113.10	1.12E-01	50,894	45.98	68.2

Bold highlights indicate interpolated values to determine PM_{10} and $PM_{2.5}$ size fractions.

[1] Based on drift droplet size distribution testing from EPRI test facility published in the Reisman and Frisbie paper.

8.2.3 Summary of PM Emission Factors

Estimated PM_{10}/PM Ratio	0.469	EPRI ratio of mass smaller than PM_{10} (based on interpolation in table above)
Estimated $PM_{2.5}$/PM Ratio	2.02E-03	EPRI ratio of mass smaller than $PM_{2.5}$ (based on interpolation in table above)

Pollutant	Emission Factor (lb/MMgal)	Basis
PM	0.0826	= 8.34 lb/gal x 990 ppm x 0.0010 drift %
PM_{10}	0.0388	= 0.0826 lb PM/MMgal circulating water x 0.469 Estimated PM10/PM Ratio
$PM_{2.5}$	1.668E-04	= 0.0826 lb PM/MMgal circulating water x 2.02E-03 Estimated PM2.5/PM Ratio

8.3 Cooling Tower Potential Emissions Summary

	Emission Factor		Potential Emissions	
Pollutant	(lb/MMgal)	Basis	(lb/hr)	(tpy)
PM	0.083	990 ppm TDS in recirculating water and 0.001% drift	0.471	2.06
PM_{10}	0.039	EPRI PM_{10}/PM ratio	0.221	0.97
$PM_{2.5}$	1.668E-04	EPRI $PM_{2.5}$/PM ratio	9.51E-04	4.16E-03

Sample Calculations:
PM (lb/hr) = 0.083 lb/MMgal x 5.7 MMgal/hr = 0.471 lb/hr PM
PM (tpy) = 0.471 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 2.06 tpy PM

9. Diesel-Fired Emergency Generator Engine - Emissions Calculations

> A new diesel-fired emergency generator will be installed as part of the NGCC project to supply power in the event of a power outage. Potential emissions for the emergency generator are documented in this section.

9.1 Emergency Generator Nomenclature and Specifications

> Proposed nomenclature for the new Emergency Generator associated with the NGCC Plant:

Emission Unit:	**U25 - 2 MW Diesel Emergency Generator**
Emission Point:	E51 - Diesel Fuel Combustion
Control Device:	-- - --
Stack ID:	S51

> LG&E plans to provision a diesel-fired emergency generator for the NGCC project. The specific make and model will not be known until farther on in the project phase. However, the maximum engine rating will be 2 MW or less For permitting purposes and to calculate potential emissions, this maximum rating is assumed.

SCC Code	20200102
SCC Description	Internal Combustion Engines - Industrial (2-02) - Distillate Oil (Diesel) (2-02-001) - Reciprocating (2-02-001-02)
SCC Units	1000 Gallons Distillate Oil (Diesel) Burned

Generator Rating	**2,000**	**kW**	Maximum required generator power output
Engine Rating	2,682	bhp	Converted
Annual Operating Hours	500	hr/yr	The PTE of emergency generators may be based on 500 operating hours annually per EPA guidance.
Diesel Heating Value:	137.03	MMBtu/Mgal	Assume heating value of 137,030 Btu/gallon for diesel fuel based on AP-42, Table 3.4-1, Footnote 'a', i.e., 19300 Btu/lb * 7.1 lb/gallon = 137,000 Btu/gallon
Avg Brake-Specific Fuel Consumption	7,000	Btu/hp-hr	AP-42, Chapter 3.3 Gasoline and Diesel Industrial Engines, Table 3.3-1 Footnote a
Maximum Fuel Consumption	0.137	Mgal/hr	= 2,682 bhp x 7,000 Btu/hp-hr / 1E6 Btu/MMBtu / 137.03 MMBtu/Mgal

9.2 Derivation and Documentation of Emission Factors

> While the exact make and model of the emergency engine is not known, it is assumed that the engine will be compliant with the Tier 2 emission standards for generator output greater than 560 kW. Used a manufacturer datasheet for a similarly sized Tier 2 engine provides the emission factors for NO_X, VOC, CO, and $PM/PM_{10}/PM_{2.5}$. Engine will be a CAT 3516C Diesel GenSet with a 3516C, ATAAC, V-16,4-Stroke Water-Cooled Diesel or similar. Emission factors for NSR-regulated pollutants not included in the manufacturer's emissions data are from AP-42, Section 3.4 Large Stationary Diesel and All Stationary Dual-Fuel Engines (for other criteria pollutants and HAP), and 40 CFR 98, Subpart C, Table C-2 (for non-CO_2 greenhouse gases).

NO_X

Emission factor for NO_X:	6.56	g/hp-hr	Manufacturer Emissions Datasheet
NO_X emission factor in terms of SCC units:	283.110	lb/Mgal	= 6.56 g/hp-hr x 2,682 bhp / 0.137 Mgal/hr / 453.593 gm/lb

VOC

Emission factor for VOC:	0.14	g/hp-hr	Manufacturer Emissions Datasheet
VOC emission factor in terms of SCC units:	6.042	lb/Mgal	= 0.14 g/hp-hr x 2,682 bhp / 0.137 Mgal/hr / 453.593 gm/lb

CO

Emission factor for CO:	0.54	g/hp-hr	Manufacturer Emissions Datasheet
CO emission factor in terms of SCC units:	23.305	lb/Mgal	= 0.54 g/hp-hr x 2,682 bhp / 0.137 Mgal/hr / 453.593 gm/lb

$PM/PM_{10}/PM_{2.5}$

Emission factor for $PM/PM_{10}/PM_{2.5}$:	0.04	g/hp-hr	Manufacturer Emissions Datasheet
$PM/PM_{10}/PM_{2.5}$ emission factor in terms of SCC units:	1.726	lb/Mgal	= 0.04 g/hp-hr x 2,682 bhp / 0.137 Mgal/hr / 453.593 gm/lb

SO_2

> To take into account the lower sulfur content of the diesel fuel burned, and for purposes of representing SO_2 emissions from the engine, the factor in AP-42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO_2 as a function of sulfur content. As required under NSPS Subpart IIII, ultra low sulfur diesel (ULSD) must be used in the new emergency generator engine.

AP-42 Factor for SO_2 based on sulfur content:	1.01 S	lb/MMBtu	AP-42 Table 3.4-1 (S is sulfur content in %)
Sulfur Content:	0.0015	%	Based on maximum sulfur content in ULSD of 15 ppm
SO_2 emission factor (lb/MMBtu):	1.52E-03	lb/MMBtu	= 1.01 EF x 0.0015%, sulfur
SO_2 emission factor in terms of SCC units:	0.208	lb/Mgal	= 1.52E-03 lb/MMBtu x 137 MMBtu/Mgal

Greenhouse Gases

> CO_2, CH_4 and N_2O emissions for diesel fuel combustion are estimated using the Distillate Fuel Oil No. 2 emission factors published in 40 CFR 98, Subpart C, Table C-1 & 2. CO_2e emissions for diesel fuel combustion are estimated using the global warming potentials published in 40 CFR 98, Subpart A, Table A-1.

Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.

CO_2	1
CH_4	25
N_2O	298

Pollutant	Emission Factor (kg/MMBtu)	Equivalent Factor (lb/Mgal)	
CO_2	73.96	22,343	40 CFR 98, Subpart C, Table C-1; Distillate Fuel Oil No. 2
CH_4	3.00E-03	0.906	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
N_2O	6.00E-04	0.181	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
CO_2e	74.21	22,420	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

9.2.1 Hazardous Air Pollutants

> Emission factors for organic HAP compounds expected to be emitted are based on emission factors in AP-42 Table 3.4-3 and 3.4-4 (10/96 Edition). Emission factors are converted from lb/MMBtu as provided in AP-42 to lb/Mgal as applicable to the SCC designation.

> Pollutants listed below designated as Toxic Air Contaminants (TACs) under Jefferson County's STAR Regulation (Reg 5.01) are indicated as such and are compared with their De Minimis Thresholds calculated using the Benchmark Ambient Concentration (BAC) for the TAC.

> The emission factor shown for diesel particulate matter is the engine's PM emission factor pulled from the manufacturer emissions data sheet. Diesel particulate is included in this list because it is regulated as a TAC under Reg 5.01.

> TAC emissions from the engine are below de minimis for all TACs except diesel particulate. For diesel particulate, a modeling analysis was completed to demonstrate that offsite impacts comply with BAC standards. Refer to Section 5.7 in the Application Report.

Pollutant	CAS #	HAP?	TAC?	Emission Factor (lb/MMBtu)	Emission Factor (lb/Mgal)	Uncontrld Emissions (lb/yr)	*Minimis* Threshold (lb/yr)	Below *De Minimis* ?
Acetaldehyde	75-07-0	Y	Y	2.52E-05	3.45E-03	0.237	216.00	Y
Acrolein	107-02-8	Y	Y	7.88E-06	1.08E-03	0.074	9.60	Y
Benzene	71-43-2	Y	Y	7.76E-04	1.06E-01	7.284	216.00	Y
Formaldehyde	50-00-0	Y	Y	7.89E-05	1.08E-02	0.741	36.96	Y
Naphthalene	91-20-3	Y	Y	1.30E-04	1.78E-02	1.220	13.92	Y
PAH	--	Y		2.12E-04	2.91E-02	1.990		
Toluene	108-88-3	Y	Y	2.81E-04	3.85E-02	2.638	2,400,000	Y
Xylenes	1330-20-7	Y	Y	1.93E-04	2.64E-02	1.812	48,000	Y
Acenaphthylene	208-96-8	Y	N	9.23E-06	1.26E-03	0.087	--	--
Acenaphthene	83-32-9	Y	N	4.68E-06	6.41E-04	0.044	--	--
Fluorene	86-73-7	Y	N	1.28E-05	1.75E-03	0.120	--	--
Phenanthrene	85-01-8	Y	N	4.08E-05	5.59E-03	0.383	--	--
Anthracene	120-12-7	Y	N	1.23E-06	1.69E-04	0.012	--	--
Fluoranthene	206-44-0	Y	N	4.03E-06	5.52E-04	0.038	--	--
Pyrene	129-00-0	Y	N	3.71E-06	5.08E-04	0.035	--	--
Benzo(a)anthracene	56-55-3	Y	Y	6.22E-07	8.52E-05	0.006	4.37	Y
Chrysene	218-01-9	Y	Y	1.53E-06	2.10E-04	0.014	43.68	Y
Benzo(b)fluoranthene	205-99-2	Y	Y	1.11E-06	1.52E-04	0.010	4.37	Y
Benzo(k)fluoranthene	207-08-9	Y	Y	2.18E-07	2.99E-05	0.002	4.37	Y
Benzo(a)pyrene	50-32-8	Y	Y	4.50E-06	6.16E-04	0.042	0.44	Y
Indeno (1,2,3-cd)pyrene	193-39-5	Y	Y	4.14E-07	5.67E-05	0.004	4.37	Y
Dibenz(a,h)anthracene	53-70-3	Y	Y	3.46E-07	4.74E-05	0.003	0.40	Y
Benzo(g,h,i)perylene	191-24-2	Y	N	5.56E-07	7.62E-05	0.005	--	--
Diesel particulate matter	--	N	Y	1.26E-02	1.73E+00	118.258	1.58	N

9.3 Emergency Generator Potential Emissions Summary

Pollutant	Emission Factor (lb/Mgal)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NOx	283.110	Manufacturer Emissions Datasheet	38.789	9.70
CO	23.305	Manufacturer Emissions Datasheet	3.193	0.80
VOC	6.042	Manufacturer Emissions Datasheet	0.828	0.207
PM/PM10/PM2.5	1.726	Manufacturer Emissions Datasheet	0.237	0.059
SO2	0.208	AP-42 Table 3.4-1 (S is sulfur content in %)	0.028	0.007
CO2e	22,420	40 CFR 98, Subpart C	3,072	767.93
Hazardous Air Pollutants				
Acetaldehyde	0.0035	AP-42 Table 3.4-3	4.73E-04	1.18E-04
Acrolein	0.0011	AP-42 Table 3.4-3	1.48E-04	3.70E-05
Benzene	0.106	AP-42 Table 3.4-3	1.46E-02	3.64E-03
Formaldehyde	0.011	AP-42 Table 3.4-3	1.48E-03	3.70E-04
Naphthalene	0.018	AP-42 Table 3.4-4	2.44E-03	6.10E-04
PAH	0.029	AP-42 Table 3.4-4	3.98E-03	9.95E-04
Toluene	0.039	AP-42 Table 3.4-3	5.28E-03	1.32E-03
Xylenes	0.026	AP-42 Table 3.4-3	3.62E-03	9.06E-04
Total HAP	0.233	AP-42 Table 3.4-3	3.20E-02	8.00E-03

Sample Calculations:

NOx (lb/hr) = 283.110 lb/Mgal x 0.137 Mgal/hr = 38.789 lb/hr NOx

NOx (tpy) = 38.789 lb/hr x 500 hr/yr / 2,000 lb/ton = 9.70 tpy NOx

Example Spec Sheet

Cat® 3516C

Diesel Generator Sets

Image shown may not reflect actual configuration

Bore – mm (in)	170 (6.69)
Stroke – mm (in)	190 (7.48)
Displacement – L (in³)	69 (4210.64)
Compression Ratio	14.7:1
Aspiration	TA
Fuel System	EUI
Governor Type	ADEM™ A3

Standby 60 Hz ekW (kVA)	Mission Critical 60 Hz ekW (kVA)	Prime 60 Hz ekW (kVA)	Continuous 60 Hz ekW (kVA)	Emissions Performance
2000 (2500)	2000 (2500)	1825 (2281)	1650 (2063)	U.S. EPA Stationary Emergency Use Only (Tier 2)

Features

Cat® Diesel Engine
- Meets U.S. EPA Stationary Emergency Use Only (Tier 2) emission standards
- Reliable performance proven in thousands of applications worldwide

Generator Set Package
- Accepts 100% block load in one step and meets NFPA 110 loading requirements
- Conforms to ISO 8528-5 G3 load acceptance requirements
- Reliability verified through torsional vibration, fuel consumption, oil consumption, transient performance, and endurance testing

Alternators
- Superior motor starting capability minimizes need for oversizing generator
- Designed to match performance and output characteristics of Cat diesel engines

Cooling System
- Cooling systems available to operate in ambient temperatures up to 50°C (122°F)
- Tested to ensure proper generator set cooling

EMCP 4 Control Panels
- User-friendly interface and navigation
- Scalable system to meet a wide range of installation requirements
- Expansion modules and site specific programming for specific customer requirements

Warranty
- 24 months/1000-hour warranty for standby and mission critical ratings
- 12 months/unlimited hour warranty for prime and continuous ratings
- Extended service protection is available to provide extended coverage options

Worldwide Product Support
- Cat dealers have over 1,800 dealer branch stores operating in 200 countries
- Your local Cat dealer provides extensive post-sale support, including maintenance and repair agreements

Financing
- Caterpillar offers an array of financial products to help you succeed through financial service excellence
- Options include loans, finance lease, operating lease, working capital, and revolving line of credit
- Contact your local Cat dealer for availability in your region

Package Performance

Performance	Standby	Mission Critical	Prime	Continuous
Frequency	60 Hz	60 Hz	60 Hz	60 Hz
Gen set power rating with fan	2000 ekW	2000 ekW	1825 ekW	1650 ekW
Gen set power rating with fan @ 0.8 power factor	2500 kVA	2500 kVA	2281 kVA	2063 kVA
Emissions	EPA ESE (TIER 2)	EPA ESE (TIER 2)	EPA ESE (TIER 2)	EPA ESE (TIER 2)
Performance number	EM1896-03	EM1897-03	DM8264-06	DM8265-05
Fuel Consumption				
100% load with fan – L/hr (gal/hr)	505.8 (133.6)	505.8 (133.6)	465.6 (123.0)	427.9 (113.0)
75% load with fan – L/hr (gal/hr)	393.9 (104.1)	393.9 (104.1)	366.7 (96.9)	338.3 (89.4)
50% load with fan – L/hr (gal/hr)	284.2 (75.1)	284.2 (75.1)	261.3 (69.0)	238.3 (63.0)
25% load with fan – L/hr (gal/hr)	164.3 (43.4)	164.3 (43.4	154.2 (40.7)	144.1 (38.1)
Cooling System				
Radiator air flow restriction (system) – kPa (in. water)	0.12 (0.48)	0.12 (0.48)	0.12 (0.48)	0.12 (0.48)
Radiator air flow – m^3/min (cfm)	2204 (77834)	2204 (77834)	2204 (77834)	2204 (77834)
Engine coolant capacity – L (gal)	233.2 (61.6)	233.2 (61.6)	233.2 (61.6)	233.2 (61.6)
Radiator coolant capacity – L (gal)	180.0 (47.6)	180.0 (47.6)	180.0 (47.6)	180.0 (47.6)
Total coolant capacity – L (gal)	413.2 (109.2)	413.2 (109.2)	413.2 (109.2)	413.2 (109.2)
Inlet Air				
Combustion air inlet flow rate – m^3/min (cfm)	185.5 (6548.9)	185.5 (6548.9)	180.0 (6357.6)	174.3 (6155.8)
Exhaust System				
Exhaust stack gas temperature – °C (°F)	400.1 (752.1)	400.1 (752.1)	382.8 (721.1)	370.7 (699.3)
Exhaust gas flow rate – m^3/min (cfm)	433.1 (15292.8)	433.1 (15292.8)	408.1 (14410.4)	385.3 (13605.7)
Exhaust system backpressure (maximum allowable) – kPa (in. water)	6.7 (27.0)	6.7 (27.0)	6.7 (27.0)	6.7 (27.0)
Heat Rejection				
Heat rejection to jacket water – kW (Btu/min)	759 (43150)	759 (43150)	715 (40666)	673 (38277)
Heat rejection to exhaust (total) – kW (Btu/min)	1788 (101696)	1788 (101696)	1645 (93554)	1522 (86577)
Heat rejection to aftercooler – kW (Btu/min)	672 (38240)	672 (38240)	612 (34784)	553 (31421)
Heat rejection to atmosphere from engine – kW (Btu/min)	133 (7564)	133 (7564)	127 (7230)	123 (6983)
Heat rejection from alternator – kW (Btu/min)	96 (5464)	96 (5464)	86 (4895)	76 (4326)
Emissions* (Nominal)				
NOx mg/Nm^3 (g/hp-h)	2754.3 (5.46)	2754.3 (5.46)	2488.9 (5.05)	2202.3 (4.37)
CO mg/Nm^3 (g/hp-h)	143.3 (0.30)	143.3 (0.30)	129.7 (0.27)	112.3 (0.24)
HC mg/Nm^3 (g/hp-h)	44.7 (0.11)	44.7 (0.11)	55.6 (0.13)	67.4 (0.16)
PM mg/Nm^3 (g/hp-h)	10.4 (0.03)	10.4 (0.03)	10.9 (0.03)	12.0 (0.03)
Emissions* (Potential Site Variation)				
NOx mg/Nm^3 (g/hp-h)	3305.2 (6.56)	3305.2 (6.56)	2986.6 (6.06)	2642.7 (5.24)
CO mg/Nm^3 (g/hp-h)	258.0 (0.54)	258.0 (0.54)	233.4 (0.49)	202.1 (0.43)
HC mg/Nm^3 (g/hp-h)	59.5 (0.14)	59.5 (0.14)	73.9 (0.18)	89.6 (0.22)
PM mg/Nm^3 (g/hp-h)	14.6 (0.04)	14.6 (0.04)	15.3 (0.04)	16.8 (0.04)

**mg/Nm^3 levels are corrected to 5% O_2. Contact your local Cat dealer for further information.*

10. Diesel-Fired Emergency Fire Pump Engine - Emissions Calculations

> A new diesel-fired emergency fire pump engine will be installed as part of the NGCC project to supply water in the event of a fire and/or power outage. Potential emissions for the emergency fire pump engine are documented in this section.

10.1 Emergency Fire Pump Engine Nomenclature and Specifications

> Proposed nomenclature for the new Emergency Fire Pump Engine associated with the NGCC Plant:

Emission Unit:	**IA4 - 400 HP Diesel Driven Fire Pump**
Emission Point:	IE28 - Diesel Fuel Combustion
Control Device:	-- - --
Stack ID:	S53

> LG&E plans to provision a diesel-fired emergency fire pump engine for the NGCC project. The specific make and model will not be known until farther on in the project phase. However, the maximum engine rating will be 400 hp or less For permitting purposes and to calculate potential emissions, this maximum rating is assumed.

SCC Code	20200102
SCC Description	Internal Combustion Engines - Industrial (2-02) - Distillate Oil (Diesel) (2-02-001) - Reciprocating (2-02-001-02)
SCC Units	1000 Gallons Distillate Oil (Diesel) Burned

Engine Rating	**400**	**bhp**	
Annual Operating Hours	500	hr/yr	The PTE of emergency engines may be based on 500 operating hours annually per EPA guidance.
Diesel Heating Value:	137.03	MMBtu/Mgal	Assume heating value of 137,030 Btu/gallon for diesel fuel based on AP-42, Table 3.4-1, Footnote 'a', i.e., 19300 Btu/lb * 7.1 lb/gallon = 137,000 Btu/gallon
Avg Brake-Specific Fuel Consumption	7,000	Btu/hp-hr	AP-42, Chapter 3.3 Gasoline and Diesel Industrial Engines, Table 3.3-1 Footnote a
Maximum Fuel Consumption	0.020	Mgal/hr	= 400 bhp x 7,000 Btu/hp-hr / 1E6 Btu/MMBtu / 137.03 MMBtu/Mgal

10.2 Derivation and Documentation of Emission Factors

> While the exact make and model of the fire pump engine is not known, it is assumed that the engine will be compliant with the NSPS IIII Table 4 emission standards for engine ratings greater than 300 HP, but less than 600 HP. A manufacturer datasheet for a similarly sized engine provides the emission factors for NO_X, VOC, CO, and $PM/PM_{10}/PM_{2.5}$. Emission factors for NSR-regulated pollutants not included in the manufacturer's emissions data are from AP-42, Section 3.3 Gasoline and Diesel Industrial Engines (for other criteria pollutants and HAP), and 40 CFR 98, Subpart C, Table C-2 (for non-CO_2 greenhouse gases).

NO_X

Emission factor for NO_X:	2.61	g/hp-hr	Manufacturer Emissions Datasheet
NO_X emission factor in terms of SCC units:	112.640	lb/Mgal	= 2.61 g/hp-hr x 400 bhp / 0.020 Mgal/hr / 453.593 gm/lb

VOC

Emission factor for VOC:	0.10	g/hp-hr	Manufacturer Emissions Datasheet
VOC emission factor in terms of SCC units:	4.316	lb/Mgal	= 0.10 g/hp-hr x 400 bhp / 0.020 Mgal/hr / 453.593 gm/lb

CO

Emission factor for CO:	0.80	g/hp-hr	Manufacturer Emissions Datasheet
CO emission factor in terms of SCC units:	34.526	lb/Mgal	= 0.80 g/hp-hr x 400 bhp / 0.020 Mgal/hr / 453.593 gm/lb

$PM/PM_{10}/PM_{2.5}$

Emission factor for $PM/PM_{10}/PM_{2.5}$:	0.10	g/hp-hr	Manufacturer Emissions Datasheet
$PM/PM_{10}/PM_{2.5}$ emission factor in terms of SCC units:	4.316	lb/Mgal	= 0.10 g/hp-hr x 400 bhp / 0.020 Mgal/hr / 453.593 gm/lb

SO_2

> To take into account the lower sulfur content of the diesel fuel burned, and for purposes of representing SO_2 emissions from the engine, the factor in AP-42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO_2 as a function of sulfur content. As required under NSPS Subpart IIII, the ultra low sulfur diesel (ULSD) must be used in the new emergency generator engine.

AP-42 Factor for SO_2 based on sulfur content:	1.01 S	lb/MMBtu	AP-42 Table 3.4-1 (S is sulfur content in %)
Sulfur Content:	0.0015	%	Based on maximum sulfur content in ULSD of 15 ppm
SO_2 emission factor (lb/MMBtu):	1.52E-03	lb/MMBtu	= 1.01 EF x 0.0015%, sulfur
SO_2 emission factor in terms of SCC units:	0.208	lb/Mgal	= 1.52E-03 lb/MMBtu x 137 MMBtu/Mgal

Greenhouse Gases

> CO_2, CH_4 and N_2O emissions for diesel fuel combustion are estimated using the Distillate Fuel Oil No. 2 emission factors published in 40 CFR 98, Subpart C, Table C-1 & 2. CO_2e emissions for diesel fuel combustion are estimated using the global warming potentials published in 40 CFR 98, Subpart A, Table A-1.

Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.

CO_2	1
CH_4	25
N_2O	298

Pollutant	Emission Factor (kg/MMBtu)	Equivalent Factor (lb/Mgal)	
CO_2	73.96	22,343	40 CFR 98, Subpart C, Table C-1; Distillate Fuel Oil No. 2
CH_4	3.00E-03	0.906	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
N_2O	6.00E-04	0.181	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
CO_2e	74.21	22,420	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

10.2.1 Hazardous Air Pollutants

> Emission factors for organic HAP compounds expected to be emitted are based on emission factors in AP-42 Table 3.4-3 and 3.4-4 (10/96 Edition).
> Pollutants listed below designated as Toxic Air Contaminants (TACs) under Jefferson County's STAR Regulation (Reg 5.01) are indicated as such
> The emission factor shown for diesel particulate matter is the engine's PM emission factor pulled from the manufacturer emissions data sheet. Diesel
> TAC emissions from the engine are below de minimis for all TACs except diesel particulate. For diesel particulate, a modeling analysis was

Pollutant	CAS #	HAP?	TAC?	Emission Factor (lb/MMBtu)	Emission Factor (lb/Mgal)	Uncontrld Emissions (lb/yr)	*De Minimis* Threshold (lb/yr)	Below *De Minimis* ?
1,3-Butadiene	106-99-0	Y	Y	3.91E-05	5.36E-03	0.055	15.84	Y
Acetaldehyde	75-07-0	Y	Y	7.67E-04	1.05E-01	1.074	216.00	Y
Acrolein	107-02-8	Y	Y	9.25E-05	1.27E-02	0.130	9.60	Y
Benzene	71-43-2	Y	Y	9.33E-04	1.28E-01	1.306	216.00	Y
Formaldehyde	50-00-0	Y	Y	1.18E-03	1.62E-01	1.652	36.96	Y
Naphthalene	91-20-3	Y	Y	8.48E-05	1.16E-02	0.119	13.92	Y
PAH		Y		1.68E-04	2.30E-02	0.235		
Toluene	108-88-3	Y	Y	4.09E-04	5.60E-02	0.573	2,400,000	Y
Xylenes	1330-20-7	Y	Y	2.85E-04	3.91E-02	0.399	48,000	Y
Phenanthrene	85-01-8	Y	N	2.94E-05	4.03E-03	0.041	--	--
Fluorene	86-73-7	Y	N	2.92E-05	4.00E-03	0.041	--	--
Acenaphthylene	208-96-8	Y	N	5.06E-06	6.93E-04	0.007	--	--
Acenaphthene	83-32-9	Y	N	1.42E-06	1.95E-04	0.002	--	--
Fluoranthene	206-44-0	Y	N	7.61E-06	1.04E-03	0.011	--	--
Pyrene	129-00-0	Y	N	4.78E-06	6.55E-04	0.007	--	--
Chrysene	218-01-9	Y	Y	3.53E-07	4.84E-05	0.000	43.68	Y
Anthracene	120-12-7	Y	N	1.87E-06	2.56E-04	0.003	--	--
Benzo(b)fluoranthene	205-99-2	Y	Y	9.91E-08	1.36E-05	0.000	4.37	Y
Benzo(a)anthracene	56-55-3	Y	Y	1.68E-06	2.30E-04	0.002	4.37	Y
Benzo(g,h,i)perylene	191-24-2	Y	N	4.89E-07	6.70E-05	0.001	--	--
Indeno (1,2,3-cd)pyrene	193-39-5	Y	Y	3.75E-07	5.14E-05	0.001	4.37	Y
Dibenz(a,h)anthracene	53-70-3	Y	Y	5.83E-07	7.99E-05	0.001	0.40	Y
Benzo(a)pyrene	50-32-8	Y	Y	1.88E-07	2.58E-05	0.000	0.44	Y
Benzo(k)fluoranthene	207-08-9	Y	Y	1.55E-07	2.12E-05	0.000	4.37	Y
Diesel particulate matter	--	N	Y	3.15E-02	4.32E+00	44.092	1.58	N

10.3 Emergency Fire Pump Engine Potential Emissions Summary

	Emission Factor		Potential Emissions	
Pollutant	(lb/Mgal)	Basis	(lb/hr)	(tpy)
NOx	112.640	Manufacturer Emissions Datasheet	2.302	0.575
CO	34.526	Manufacturer Emissions Datasheet	0.705	0.176
VOC	4.316	Manufacturer Emissions Datasheet	0.088	0.022
PM/PM10/PM2.5	4.316	Manufacturer Emissions Datasheet	0.088	0.022
SO2	0.208	AP-42 Table 3.4-1 (S is sulfur content in %)	0.004	0.001
CO2e	22,420	40 CFR 98, Subpart C	458	114.529
Hazardous Air Pollutants				
1,3-Butadiene	0.005	AP-42 Table 3.3-2	1.09E-04	2.74E-05
Acetaldehyde	0.105	AP-42 Table 3.3-2	2.15E-03	5.37E-04
Acrolein	0.013	AP-42 Table 3.3-2	2.59E-04	6.48E-05
Benzene	0.128	AP-42 Table 3.3-2	2.61E-03	6.53E-04
Formaldehyde	0.162	AP-42 Table 3.3-2	3.30E-03	8.26E-04
Naphthalene	0.012	AP-42 Table 3.3-2	2.37E-04	5.94E-05
PAH	0.023	AP-42 Table 3.3-2	4.71E-04	1.18E-04
Toluene	0.056	AP-42 Table 3.3-2	1.15E-03	2.86E-04
Xylenes	0.039	AP-42 Table 3.3-2	7.98E-04	2.00E-04
Total HAP	0.542	AP-42 Table 3.3-2	1.11E-02	2.77E-03

Sample Calculations:
NOx (lb/hr) = 112.640 lb/Mgal x 0.020 Mgal/hr = 2.302 lb/hr NOx
NOx (tpy) = 2.302 lb/hr x 500 hr/yr / 2,000 lb/ton = 0.575 tpy NOx

Example Spec Sheet

CLARKE®

Rating Specific Emissions Data

Nameplate Rating Information

Clarke Model	**JW6H-UFAD80**
Power Rating (BHP/kW)	**400/298**
Certified Speed (RPM)	**2100**

Refer to **Rating Data** section on page 2 for emissions output values

Rating Specific Emissions Data - John Deere Power Systems

JOHN DEERE

Rating Data

Rating	6090HFC47B	
Certified Power(kW)	298	
Rated Speed	2100	
Vehicle Model Number	OEM (Clarke Fire Pump-Emergency)	
Units	g/kW-hr	g/hp-hr
NOx	3.50	2.61
HC	0.14	0.10
NOx + HC	N/A	N/A
Pm	0.14	0.10
CO	1.1	0.8

Certificate Data

Engine Model Year	2022
EPA Family Name	NJDXL09.0114
EPA JD Name	450HAB
EPA Certificate Number	NJDXL09.0114-007
CARB Executive Order	
Parent of Family	6090HFG84A
Units	g/kW-hr
NOx	3.80
HC	0.05
NOx + HC	N/A
Pm	0.11
CO	0.9

* The emission data listed is measured from a laboratory test engine according to the test procedures of 40 CFR 89 or 40 CFR 1039, as applicable. The test engine is intended to represent nominal production hardware, and we do not guarantee that every production engine will have identical test results. The family parent data represents multiple ratings and this data may have been collected at a different engine speed and load. Emission results may vary due to engine manufacturing tolerances, engine operating conditions, fuels used, or other conditions beyond our control.

Emissions Results by Rating run on Apr-05-2022

11. HVAC Heaters - Emissions Calculations

> LG&E expects to install several HVAC heaters for the new buildings that are associated with the NGCC project to provide heating in winter months as needed. Potential emissions for the HVAC heaters are documented in this section.

11.1 HVAC Heaters Nomenclature and Specifications

> Proposed nomenclature for the new HVAC heaters associated with the NGCC Plant:

Emission Unit:	**IA5 - Other Insignificant Activities**
Emission Point:	IE27 - HVAC Heaters (Total 10 MMBtu/hr)
Control Device:	-- - --
Stack ID:	Fugitive

> LG&E plans to provision multiple natural gas-fired HVAC units within building that support the NGCC project. The specific make and model are TBD. The total combined heat input capacity of all small HVAC heaters is assumed to be 10 MMBtu/hr or less. For permitting purposes and to calculate potential emissions, the maximum combined heat input capacity is assumed.

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**10**	**MMBtu/hr**	
NG Heating Value	1,059	Btu/scf	Average for Mill Creek Generating Station Inlet Gas
Max Gas Firing Rate at Average HHV	0.0094	MMscf/hr	10 MMBtu/hr / 1,059 MMBtu/MMscf = 0.0094 MMscf/hr
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	

11.2 Derivation and Documentation of Emission Factors

11.2.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm x 0.7302 cf-atm/(lbmol-°R)
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO2	64.07	lb SO_2/lbmol	
Molecular Weight of H2SO4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for Mill Creek inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

11.2.2 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NOx	10102-44-0	0.098	100	AP-42 Section 1.4 Table 1.4-1 for Uncontrolled Small Boilers (7/98)
CO	00630-08-0	0.082	84	AP-42 Section 1.4 Table 1.4-1 for Uncontrolled Small Boilers (7/98)
VOC	na	0.005	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM/PM10/PM2.5-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Table 1.4-2 + EPA Speciate Database
PM/PM10/PM2.5 Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
SO2	07446-09-5	0.0013	1.427	0.5 gr/Ccf / 7,000 gr/lb x 64.07 lb SO2/lbmol / 32.07 lb S/lbmol x 10,000
H2SO4	7664-93-9	1.03E-04	0.109	5% conversion of SO2 to SO3 and 100% conversion of SO3 to H2SO4 1.427 lb SO2/MMscf x 5% x 100% x 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol = 0.109 lb/MMscf
Lead		4.72E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO2		116.98	123,879	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH4		0.0022	2.33	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N2O		0.0002	0.233	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO2e		117.10	124,007	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

11.2.3 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.8E+00
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.888

11.3 HVAC Heaters Potential Emissions Summary

Pollutant	Emission Factor (lb/MMscf)	Emission Factor Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_X	100	AP-42 Table 1.4-1	0.944	4.136
CO	84	AP-42 Table 1.4-1	0.793	3.474
VOC	5.5	AP-42 Table 1.4-2	0.052	0.227
PM/PM10/PM2.5-Filt	1.9	AP-42 Table 1.4-2	0.018	0.079
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.015	0.065
PM/PM10/PM2.5 Total	3.47	AP-42 Table 1.4-2	0.033	0.144
SO2	1.43	Pipeline spec conversion	0.013	0.059
H2SO4	0.109	Pipeline spec conversion	1.03E-03	4.52E-03
Lead	0.0005	AP-42, Table 1.4-2	4.72E-06	2.07E-05
CO2e	124,007	40 CFR 98, Table C-1	1,171	5,129
Hazardous Air Pollutants	1.888	Sum of HAPs	0.018	0.078
Benzene	2.1E-03	AP-42, Table 1.4-3	1.98E-05	8.69E-05
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	1.13E-05	4.96E-05
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	7.08E-04	3.10E-03
Hexane	1.8E+00	AP-42, Table 1.4-3	1.70E-02	7.44E-02
Naphthalene	6.1E-04	AP-42, Table 1.4-3	5.76E-06	2.52E-05
Toluene	3.4E-03	AP-42, Table 1.4-3	3.21E-05	1.41E-04
Arsenic	2.0E-04	AP-42, Table 1.4-4	1.89E-06	8.27E-06
Cadmium	1.1E-03	AP-42, Table 1.4-4	1.04E-05	4.55E-05
Chromium	1.4E-03	AP-42, Table 1.4-4	1.32E-05	5.79E-05
Manganese	3.8E-04	AP-42, Table 1.4-4	3.59E-06	1.57E-05
Mercury	2.6E-04	AP-42, Table 1.4-4	2.46E-06	1.08E-05
Nickel	2.1E-03	AP-42, Table 1.4-4	1.98E-05	8.69E-05

Sample Calculations:

NOx (lb/hr) = 100 lb/MMscf x 0.0094 MMscf/hr = 0.944 lb/hr NOx

NOx (tpy) = 0.944 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 4.136 tpy NOx

12. Lube Oil Demister Vents - Emission Calculations

> LG&E plans to provision multiple lube oil storage tanks for the NGCC project. The storage tanks will be equipped with demister vents which will be a source of fugitive VOC emissions. Potential VOC emissions from the demister vents are documented in this section.

12.1 Lube Oil Demister Vents Nomenclature and Specifications

> Proposed nomenclature for the new lube oil demister vents associated with the NGCC Plant:

Emission Unit: **IA5 - Other Insignificant Activities**
Emission Point: IE25 - Lube Oil Storage Tanks with Demister Vents
Control Device: -- - --
Stack ID: Fugitive

> The working losses conservatively assume that all lube oil consumed/replaced will evaporate and contribute to VOC emissions. Similar to LG&E's Cane Run NGCC project, at most 110 and 73 gallons per year of lube oil will be added to the GT and STG, respectively.

Max Annual Operating Hours	8,760	hr/yr	
GT Lube Oil Consumption	0.3	gal/day	Process knowledge
	0.013	gal/hr	Unit Conversion: 0.3 gal/day / 24 hr/day
ST Lube Oil Consumption	0.2	gal/day	Process knowledge
	0.008	gal/hr	Unit Conversion: 0.2 gal/day / 24 hr/day
Total Lube Oil Consumption	**0.021**	**gal/hr**	0.013 gal/day from GT + 0.008 gal/day from ST = 0.021 gal/hr total

12.2 Lube Oil Demister Vents Potential Emissions Summary

	Emission Factor		Potential Emissions	
Pollutant	(lb/gal)	Basis	(lb/hr)	(tpy)
VOC	7.26	Lube oil density	0.151	0.662

Sample Calculations:
VOC (lb/hr) = 7.26 lb/gal x 0.021 gal/hr = 0.151 lb/hr VOC
VOC (tpy) = 0.151 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 0.662 tpy VOC

13. Diesel Storage Tank - Emissions Calculations

> LG&E plans to provision diesel storage tanks for the NGCC project to supply fuel to the emergency generator engine and fire pump engine. Potential emissions from the diesel storage tanks are documented in this section.

13.1 Diesel Storage Tanks Nomenclature and Specifications

> This insignificant activity represents emissions from two storage tanks: one associated with the new emergency generator engine and one associated with the new fire pump engine.

> Proposed nomenclature for the new diesel storage tanks associated with the NGCC Plant:

Emission Unit:	**IA5 - Other Insignificant Activities**
Emission Point:	IE26 - Diesel Storage Tanks for NGCC Units (1@ 4,000 gal 1@ 440 gal)
Control Device:	-- - --
Stack ID:	Fugitive
Tank Type:	Fixed Roof Tanks

Emergency Generator Tank Volume	**4,000**	**gal**	Design specifications
	534.76	ft^3	Unit Conversion: 4000 gal x 7.48 ft3/gal
Emergency Generator Tank Diameter	6.98	ft	Design specifications
Emergency Generator Tank Height	13.97	ft	Design specifications
Emergency Generator Tank Throughput	68,504	gal/yr	Emergency diesel engine annual fuel consumption (based on 500 hr/yr): 0.137 Mgal/hr x 500 operating hrs/yr x 1000 gal/Mgal
	7.82	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Turnovers	17.1	turnovers/yr	68,504 gal/yr / 4000 gal = 17.13 turnovers/yr
True Vapor Pressure	0.0064	psia	Calculated by TankESP
Bulk Liquid Storage Temperature	59.00	°F	Calculated by TankESP
Average Liquid Surface Temperature	59.79	°F	Calculated by TankESP

Fire Pump Tank Volume	**440**	**gal**	Design specifications
	58.82	ft^3	Unit Conversion: 440 gal x 7.48 ft3/gal
Fire Pump Tank Diameter	3.35	ft	Design specifications
Fire Pump Tank Height	6.69	ft	Design specifications
Fire Pump Tank Throughput	10,217	gal/yr	Fire pump diesel engine annual fuel consumption (based on 500 hr/yr): 0.020 Mgal/hr x 500 operating hrs/yr x 1000 gal/Mgal
	1.17	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Turnovers	23.2	turnovers/yr	10,217 gal/yr / 440 gal = 23.22 turnovers/yr
True Vapor Pressure	0.0064	psia	Calculated by TankESP
Bulk Liquid Storage Temperature	59.00	°F	Calculated by TankESP
Average Liquid Surface Temperature	59.79	°F	Calculated by TankESP

13.2 Diesel Storage Tanks Potential Emissions Summary

Storage Tank	Pollutant	Emission Factor (lb/gal)	Basis	Annual Standing Losses (lb/yr)	Annual Working Losses (lb/yr)	Potential Emissions (lb/hr)	Potential Emissions (tpy)
Emergency Generator	VOC	2.89E-05	TankESP analysis using methodology presented in AP-42 Section 7.1	0.605	1.372	2.26E-04	9.89E-04
Fire Pump	VOC	2.66E-05	TankESP analysis using methodology presented in AP-42 Section 7.1	0.067	0.205	3.10E-05	1.36E-04

TankESP: https://www.trinityconsultants.com/software/tanks/tankesp

14. Mill Creek Unit 1 and 2 Boilers - Emission Reductions from Shutdowns

> The project covered by this permit application encompasses the planned installation of a new NGCC combustion turbine system in conjunction with the shutdown of the existing Unit 1 and Unit 2 coal boilers.

> The new NGCC unit is targeted to commence operation on April 1, 2027 following a 37-month construction and commissioning phase. Accordingly, the anticipated start of construction for the project is **March 1, 2024**.

> Based on this project schedule, the contemporaneous netting period under the PSD/NSR regulations for the project runs from March 1, 2019 (i.e., 5 years prior to start of construction) up to April 1, 2027 (anticipated date of operation).

> Since both the Unit 1 and Unit 2 boilers are completely shutting down as part of the project, their creditable contemporaneous emission decreases will be equivalent to their baseline actual emissions.

> Pursuant to 40 CFR 52.21(b)(48)(i), for any existing electric utility steam generating unit, baseline actual emissions are the average rate in tons per year at which the unit actually emitted a pollutant during any consecutive 24-month period selected by the owner/operator within the 5-year period immediately preceding the time the owner/operator begins actual construction of the project. Thus, for this project, the earliest baseline period available is the 24-month period ending February 2021 (i.e., March 2019 to February 2021).

> A separate 24-month period may be selected for defining baseline actual emissions for each pollutant. The selected baseline periods and documentation of the baseline actual emissions (and thus the equivalent emission reductions for the project) are provided in the following sub-sections for each relevant regulated NSR pollutant emitted by the Unit 1 and 2 boilers.

14.1 Unit 1 and 2 Boiler Nomenclature

	Unit 1	Unit 2
Emission Unit ID:	U1	U2
Emission Point ID:	E1	E3
Emission Unit Description:	EGU Unit 1	EGU Unit 2
Emission Point Description:	Unit 1 Boiler (3,085 MMBtu/hr)	Unit 2 Boiler (3,085 MMBtu/hr)
Control Device IDs:	C1, C26, C27	C4, C27, C28
Control Description:	ESP, PAC Injection, DSI, PJFF, FGD	ESP, PAC Injection, DSI, PJFF, FGD
Stack IDs:	S33	S33

14.2 NOx Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of NOX.

> Because Units 1 and 2 each have a NO_X CEMS, the baseline actual emissions are known directly from the CEMS data set. The monthly and overall 24-month annual average baseline actual NO_X emissions are shown in the table below.

Month	Unit 1 NO_X CEMS Emissions (tons)	Unit 2 NO_X CEMS Emissions (tons)
3/2019	77.5	287.6
4/2019	0.0	215.9
5/2019	145.6	223.9
6/2019	198.3	217.7
7/2019	239.3	229.4
8/2019	226.4	220.0
9/2019	228.2	196.7
10/2019	223.6	221.9
11/2019	202.6	230.3
12/2019	234.6	211.3
1/2020	233.6	268.1
2/2020	225.6	254.9
3/2020	191.2	274.7
4/2020	198.0	122.0
5/2020	183.3	0.0
6/2020	174.1	0.0
7/2020	192.6	0.0
8/2020	189.4	0.0
9/2020	168.9	0.0
10/2020	204.6	0.0
11/2020	183.8	194.8
12/2020	189.5	218.1
1/2021	224.5	214.2
2/2021	166.4	169.2
24-month Total	4,501.4	3,970.5
Annual Avg	**2,250.7**	**1,985.3**

14.3 SO2 and H2SO4 Baseline Actual Emissions

> LG&E has selected the 24-month period ending September 2022 for defining baseline actual emissions of SO2.

> Because Units 1 and 2 each have a SO_2 CEMS, the baseline actual emissions are known directly from the CEMS data set.

> LG&E has selected the 24-month period ending May 2021 for defining baseline actual emissions of sulfuric acid mist (H2SO4).

> H_2SO_4 emissions are calculated based on an assumed 1% conversion rate and a stack test-derived H_2SO_4 control efficiency. The 1% conversion value is codified in Table A1, Attachment H of Title V Permit O-0127-20-V.

> The H_2SO_4 control efficiency values used for Units 1 and 2 are 98.7% and 99.8%, respectively, based on stack tests conducted June 4-8, 2015 for Units 1 and 2. These control efficiency values are also mandated for emission calculation purposes in Attachment G of Title V Permit O-0127-20-V.

> The uncontrolled SO_2 emission values needed for the calculation of H_2SO_4 emissions are determined based on the reference emission factor in AP-42 Section 1.1 (Bituminous and Subbituminous Coal Combustion), Table 1.1-3 of "38S", where S is the coal sulfur content as a percentage. The 38S emission factor includes an implicit assumption that 95% of the sulfur in the coal is converted to SO_2. (S lb sulfur/100 lb coal x 2,000 lb/ton x 64 lb SO_2/32 lb S x 95% = 38 S)

14.3.1 Unit 1 Baseline Actual SO2 and H2SO4 Emissions

> The directly measured monthly emissions of SO_2 from CEMS during the baseline period are tabulated below for Unit 1. Based on the estimated uncontrolled SO_2 emissions (before the FGD), the sulfuric acid mist conversion rate, and sulfuric acid mist control efficiency, the baseline actual H_2SO_4 emissions for Unit 1 are also tabulated below.

	Unit 1 Boiler							
Month	Coal Usage (tons)	Coal Sulfur Content	SO_2 Before FGD Emission Factor (lb/ton)	SO_2 Emissions Before FGD Control (tons)	SO_2 CEMS Emissions (tons)	SO_2 Control Efficiency Achieved	H_2SO_4 Control Efficiency	H_2SO_4 Emissions (tons)
6/2019	56,145	2.59%	98.4	2,762.9	26.7	99.04%	98.7%	0.55
7/2019	71,216	2.60%	98.8	3,518.1	45.8	98.70%	98.7%	0.70
8/2019	68,476	2.60%	98.8	3,382.7	40.7	98.80%	98.7%	0.67
9/2019	67,272	2.68%	101.8	3,425.5	47.5	98.61%	98.7%	0.68
10/2019	73,422	2.79%	106.0	3,892.1	54.9	98.59%	98.7%	0.77
11/2019	64,380	2.88%	109.4	3,522.9	70.7	97.99%	98.7%	0.70
12/2019	72,906	2.88%	109.4	3,989.4	66.4	98.34%	98.7%	0.79
1/2020	71,262	2.85%	108.3	3,858.8	78.9	97.95%	98.7%	0.77
2/2020	66,244	2.81%	106.8	3,536.8	57.3	98.38%	98.7%	0.70
3/2020	59,470	2.80%	106.4	3,163.8	57.1	98.20%	98.7%	0.63
4/2020	63,995	2.78%	105.6	3,380.2	45.9	98.64%	98.7%	0.67
5/2020	63,359	2.77%	105.3	3,334.6	30.6	99.08%	98.7%	0.66
6/2020	57,413	2.77%	105.3	3,021.6	28.4	99.06%	98.7%	0.60
7/2020	65,451	2.79%	106.0	3,469.6	33.9	99.02%	98.7%	0.69
8/2020	64,748	2.82%	107.2	3,469.2	51.4	98.52%	98.7%	0.69
9/2020	55,962	2.83%	107.5	3,009.1	33.7	98.88%	98.7%	0.60
10/2020	67,634	2.84%	107.9	3,649.5	46.2	98.73%	98.7%	0.73
11/2020	62,140	2.88%	109.4	3,400.3	52.3	98.46%	98.7%	0.68
12/2020	62,047	2.90%	110.2	3,418.8	54.3	98.41%	98.7%	0.68
1/2021	79,509	2.90%	110.2	4,380.9	87.3	98.01%	98.7%	0.87
2/2021	58,020	2.91%	110.6	3,207.9	103.7	96.77%	98.7%	0.64
3/2021	6,713	2.93%	111.3	373.7	4.8	98.72%	98.7%	0.07
4/2021	68,693	2.88%	109.4	3,758.9	76.9	97.95%	98.7%	0.75
5/2021	63,321	2.94%	111.7	3,537.1	28.1	99.21%	98.7%	0.70
6/2021	3,678	2.92%	111.0	204.1	1.3	99.37%	98.7%	0.04
7/2021	50,791	2.95%	112.1	2,846.8	19.4	99.32%	98.7%	0.57
8/2021	80,745	3.00%	114.0	4,602.5	68.8	98.50%	98.7%	0.92
9/2021	71,741	3.11%	118.2	4,239.2	50.9	98.80%	98.7%	0.84
10/2021	38,722	3.14%	119.3	2,310.2	51.4	97.78%	98.7%	0.46
11/2021	70,195	3.14%	119.3	4,187.8	91.1	97.82%	98.7%	0.83
12/2021	42,904	3.13%	118.9	2,551.5	35.7	98.60%	98.7%	0.51
1/2022	59,823	3.10%	117.8	3,523.6	53.7	98.47%	98.7%	0.70
2/2022	66,254	3.10%	117.8	3,902.4	75.8	98.06%	98.7%	0.78
3/2022	78,861	3.10%	117.8	4,644.9	75.9	98.37%	98.7%	0.92
4/2022	81,016	3.11%	118.2	4,787.2	69.5	98.55%	98.7%	0.95
5/2022	28,522	3.13%	118.9	1,696.2	25.0	98.53%	98.7%	0.34
6/2022	32,774	3.16%	120.1	1,967.8	25.7	98.69%	98.7%	0.39
7/2022	8,954	3.10%	117.8	527.4	5.6	98.93%	98.7%	0.10
8/2022	0	--	--	--	0.0	--	--	--
9/2022	0	--	--	--	0.0	--	--	--

24-month Total Ending 5/2021		16.0
24-month Total Ending 9/2022	1,103.6	
Annual Avg	**551.8**	**8.0**

<u>Sample Calculations</u>: (for 7/2022)
SO2 Before FGD Emission Factor = 38 x 3.10 = 117.8 lb SO2/ton uncontrolled
SO2 Emissions Before FGD Control = 8,954 tons/mo x 117.8 lb/ton / 2,000 lb/ton = 527.4 tons SO2/mo
SO2 Control Efficiency Achieved = 1 - (5.6 tons SO2 controlled / 527.4 tons SO2 uncontrolled) = 98.93%
H2SO4 Emissions = 527.4 uncontrolled SO2 tons/mo x 1% x 98 lb H2SO4 / 64 lb SO2 x (1 - 98.7%) = 0.10 tons H2SO4/mo
SO2 Annual Average Baseline Emissions = 1,103.6 tons/24-months / 2 years/24-month = 551.8 tpy SO2
H2SO4 Annual Average Baseline Emissions = 16.0 tons/24-months / 2 years/24-month = 8.0 tpy H2SO4

14.3.2 Unit 2 Baseline Actual SO2 and H2SO4 Emissions

> The monthly directly measured emissions of SO_2 from CEMS during the baseline period are tabulated below for Unit 2. Based on the estimated uncontrolled SO_2 emissions (before the FGD), the sulfuric acid mist conversion rate, and sulfuric acid mist control efficiency, the baseline actual H_2SO_4 emissions for Unit 2 are also tabulated below.

Month	Unit 2 Boiler Coal Usage (tons)	Coal Sulfur Content	SO2 Before FGD Emission Factor (lb/ton)	SO2 Emissions Before FGD Control (tons)	SO2 CEMS Emissions (tons)	SO2 Control Efficiency Achieved	H2SO4 Control Efficiency	H2SO4 Emissions (tons)
6/2019	63,042	2.59%	98.4	3,102.3	28.0	99.10%	99.8%	0.10
7/2019	70,568	2.60%	98.8	3,486.1	43.2	98.76%	99.8%	0.11
8/2019	67,333	2.60%	98.8	3,326.3	38.8	98.83%	99.8%	0.10
9/2019	60,312	2.68%	101.8	3,071.1	46.4	98.49%	99.8%	0.09
10/2019	73,925	2.79%	106.0	3,918.8	54.5	98.61%	99.8%	0.12
11/2019	72,685	2.88%	109.4	3,977.3	76.1	98.09%	99.8%	0.12
12/2019	68,406	2.88%	109.4	3,743.2	68.5	98.17%	99.8%	0.11
1/2020	82,174	2.85%	108.3	4,449.7	90.2	97.97%	99.8%	0.14
2/2020	75,163	2.81%	106.8	4,013.0	64.5	98.39%	99.8%	0.12
3/2020	84,985	2.79%	106.0	4,505.1	69.1	98.47%	99.8%	0.14
4/2020	38,436	2.78%	105.6	2,030.2	33.5	98.35%	99.8%	0.06
5/2020	0	--	--	--	0.0	--	--	--
6/2020	0	--	--	--	0.0	--	--	--
7/2020	0	--	--	--	0.0	--	--	--
8/2020	0	--	--	--	0.0	--	--	--
9/2020	0	--	--	--	0.0	--	--	--
10/2020	0	--	--	--	0.0	--	--	--
11/2020	66,397	2.88%	109.4	3,633.2	62.6	98.28%	99.8%	0.11
12/2020	71,579	2.90%	110.2	3,944.0	63.1	98.40%	99.8%	0.12
1/2021	74,209	2.91%	110.6	4,103.0	88.1	97.85%	99.8%	0.13
2/2021	58,536	2.91%	110.6	3,236.5	106.0	96.73%	99.8%	0.10
3/2021	0	--	--	--	0.0	--	--	--
4/2021	56,824	2.88%	109.4	3,109.4	69.5	97.76%	99.8%	0.10
5/2021	10,628	2.91%	110.6	587.6	9.4	98.40%	99.8%	0.02
6/2021	66,321	2.92%	111.0	3,679.5	58.1	98.42%	99.8%	0.11
7/2021	50,791	2.92%	111.0	2,817.9	39.5	98.60%	99.8%	0.09
8/2021	0	--	--	--	0.0	--	--	--
9/2021	0	--	--	--	0.0	--	--	--
10/2021	44,741	3.13%	118.9	2,660.7	40.6	98.48%	99.8%	0.08
11/2021	77,707	3.14%	119.3	4,636.0	98.2	97.88%	99.8%	0.14
12/2021	62,787	3.13%	118.9	3,733.9	50.0	98.66%	99.8%	0.11
1/2022	63,540	3.10%	117.8	3,742.5	58.2	98.45%	99.8%	0.11
2/2022	42,818	3.10%	117.8	2,522.0	55.3	97.81%	99.8%	0.08
3/2022	78,690	3.10%	117.8	4,634.8	76.1	98.36%	99.8%	0.14
4/2022	74,462	3.11%	118.2	4,400.0	66.5	98.49%	99.8%	0.13
5/2022	0	--	--	--	5.1	--	--	--
6/2022	40,774	3.17%	120.5	2,455.8	31.5	98.72%	99.8%	0.08
7/2022	69,453	3.10%	117.8	4,090.8	62.0	98.48%	99.8%	0.13
8/2022	84,230	3.11%	118.2	4,977.2	55.4	98.89%	99.8%	0.15
9/2022	77,295	3.11%	118.2	4,567.4	87.9	98.08%	99.8%	0.14

24-month Total Ending 5/2021		1.8
24-month Total Ending 9/2022	1,183.0	
Annual Avg	**591.5**	**0.9**

Sample Calculations: (for 7/2022)
SO2 Before FGD Emission Factor = 38 x 3.10 = 117.8 lb SO2/ton uncontrolled
SO2 Emissions Before FGD Control = 69,453 tons/mo x 117.8 lb/ton / 2,000 lb/ton = 4,090.8 tons SO2/mo
SO2 Control Efficiency Achieved = 1 - (62.0 tons SO2 controlled / 4,090.8 tons SO2 uncontrolled) = 98.48%
H2SO4 Emissions = 4,090.8 uncontrolled SO2 tons/mo x 1% x 98 lb H2SO4 / 64 lb SO2 x (1 - 99.8%) = 0.13 tons H2SO4/mo
SO2 Annual Average Baseline Emissions = 1,183.0 tons/24-months / 2 years/24-month = 591.5 tpy SO2
H2SO4 Annual Average Baseline Emissions = 1.8 tons/24-months / 2 years/24-month = 0.9 tpy H2SO4

14.4 CO Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of CO.

14.4.1 CO Emission Factors

> CO emissions from Units 1 and 2 can be attributed to both coal combustion and natural gas combustion. Total emissions are based on the sum of emissions attributable to each fuel.

> LG&E has historically calculated actual CO emissions associated with coal combustion in Units 1 and 2 for annual emission inventory purposes using the reference emission factor in AP-42 Section 1.1 (Bituminous and Subbituminous Coal Combustion), Table 1.1-3, of 0.5 lb/ton. This emission factor is also mandated in Table A1, Attachment H of Title V Permit O-0127-20-V.

> LG&E has historically calculated actual CO emissions associated with natural gas combustion in Units 1 and 2 for annual emission inventory purposes using the reference emission factor in AP-42 Section 1.4 (Natural Gas Combustion), Table 1.4-1, of 84 lb/MMscf. This emission factor is also mandated in Table A2, Attachment H of Title V Permit O-0127-20-V.

CO Coal Combustion EF:	0.5	lb/ton	AP-42 1.1 (9/98), Table 1.1-3, for any type of pulverized coal dry bottom furnace
CO NG Combustion EF:	84	lb/MMscf	AP-42 1.4, Table 1.4-1, for all large (> 100 MMBtu/yr) wall-fired boilers

14.4.2 Unit 1 Baseline Actual CO Emissions

> The monthly coal and NG usage rates during the selected baseline period for Unit 1 are shown in the following table. The baseline actual CO emissions are calculated based on the respective coal and NG emission factors as shown.

Month	Unit 1 Boiler Coal Usage (tons)	CO Emissions from Coal (tons)	NG Usage (Mcf)	CO Emissions from NG (tons)	Total CO Monthly Emissions (tons)
3/2019	21,074	5.27	458	0.019	5.29
4/2019	0	0.00	0	0.000	0.00
5/2019	44,409	11.10	22,541	0.947	12.05
6/2019	56,145	14.04	6,005	0.252	14.29
7/2019	71,216	17.80	72	0.003	17.81
8/2019	68,476	17.12	256	0.011	17.13
9/2019	67,272	16.82	1,061	0.045	16.86
10/2019	73,422	18.36	193	0.008	18.36
11/2019	64,380	16.10	1,925	0.081	16.18
12/2019	72,906	18.23	21	0.001	18.23
1/2020	71,262	17.82	2,455	0.103	17.92
2/2020	66,244	16.56	24	0.001	16.56
3/2020	59,470	14.87	6,506	0.273	15.14
4/2020	63,995	16.00	3,612	0.152	16.15
5/2020	63,359	15.84	128	0.005	15.85
6/2020	57,413	14.35	3,550	0.149	14.50
7/2020	65,451	16.36	281	0.012	16.37
8/2020	64,748	16.19	134	0.006	16.19
9/2020	55,962	13.99	929	0.039	14.03
10/2020	67,634	16.91	87	0.004	16.91
11/2020	62,140	15.54	12	0.001	15.54
12/2020	62,047	15.51	5,417	0.228	15.74
1/2021	79,509	19.88	0	0.000	19.88
2/2021	58,020	14.51	2,489	0.105	14.61
24-month Total	1,436,554	359.1	58,156	2.443	361.6
Annual Avg	718,277	179.6	29,078	1.221	**180.8**

Sample Calculations: (for 12/2020)
CO Emissions from Coal = 62,047 tons/mo x 0.5 lb/ton / 2,000 lb/ton = 15.51 tons CO/mo
CO Emissions from NG = 5,417 MCF/mo / 1000 MCF/MMcf x 84 lb/MMscf / 2,000 lb/ton = 0.228 tons CO/mo
Total CO Monthly Emissions = 15.51 + 0.228 = 15.74 tons CO/mo
Annual Average Baseline Emissions = 361.6 tons/24-months / 2 years/24-month = 180.8 tpy CO

14.4.3 Unit 2 Baseline Actual CO Emissions

> The monthly coal and NG usage rates during the selected baseline period for Unit 2 are shown in the following table. The baseline actual CO emissions are calculated based on the respective coal and NG emission factors as shown.

	Unit 2 Boiler				
Month	Coal Usage (tons)	CO Emissions from Coal (tons)	NG Usage (Mcf)	CO Emissions from NG (tons)	Total CO Monthly Emissions (tons)
3/2019	73,058	18.26	2,489	0.105	18.37
4/2019	58,035	14.51	4,367	0.183	14.69
5/2019	68,309	17.08	56	0.002	17.08
6/2019	63,042	15.76	958	0.040	15.80
7/2019	70,568	17.64	163	0.007	17.65
8/2019	67,333	16.83	0	0.000	16.83
9/2019	60,312	15.08	3,274	0.138	15.22
10/2019	73,925	18.48	587	0.025	18.51
11/2019	72,685	18.17	111	0.005	18.18
12/2019	68,406	17.10	2,004	0.084	17.19
1/2020	82,174	20.54	669	0.028	20.57
2/2020	75,163	18.79	14	0.001	18.79
3/2020	84,985	21.25	319	0.013	21.26
4/2020	38,436	9.61	4,810	0.202	9.81
5/2020	0	0.00	0	0.000	0.00
6/2020	0	0.00	0	0.000	0.00
7/2020	0	0.00	0	0.000	0.00
8/2020	0	0.00	0	0.000	0.00
9/2020	0	0.00	0	0.000	0.00
10/2020	0	0.00	7,630	0.320	0.32
11/2020	66,397	16.60	10,203	0.429	17.03
12/2020	71,579	17.89	4,223	0.177	18.07
1/2021	74,209	18.55	3,598	0.151	18.70
2/2021	58,536	14.63	1,583	0.066	14.70
24-month Total	1,227,152	306.8	47,058	1.976	308.8
Annual Avg	613,576	153.4	23,529	0.988	**154.4**

Sample Calculations: (for 12/2020)
CO Emissions from Coal = 71,579 tons/mo x 0.5 lb/ton / 2,000 lb/ton = 17.89 tons CO/mo
CO Emissions from NG = 4,223 MCF/mo / 1000 MCF/MMcf x 84 lb/MMscf / 2,000 lb/ton = 0.177 tons CO/mo
Total CO Monthly Emissions = 17.89 + 0.177 = 18.07 tons CO/mo
Annual Average Baseline Emissions = 308.8 tons/24-months / 2 years/24-month = 154.4 tpy CO

14.5 VOC Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of VOC.

14.5.1 VOC Emission Factors

> VOC emissions from Units 1 and 2 can be attributed to both coal combustion and natural gas combustion. Total emissions are based on the sum of emissions attributable to each fuel.

> LG&E has historically calculated actual VOC emissions associated with coal combustion in Units 1 and 2 for annual emission inventory purposes using the reference emission factor in AP-42 Section 1.1 (Bituminous and Subbituminous Coal Combustion), Table 1.1-19, of 0.06 lb/ton. This emission factor is also mandated in Table A1, Attachment H of Title V Permit O-0127-20-V.

> LG&E has historically calculated actual VOC emissions associated with natural gas combustion in Units 1 and 2 for annual emission inventory purposes using the reference emission factor in AP-42 Section 1.4 (Natural Gas Combustion), Table 1.4-2, of 5.5 lb/MMscf. This emission factor is also mandated in Table A2, Attachment H of Title V Permit O-0127-20-V.

VOC Coal Combustion EF:	0.06	lb/ton	AP-42 1.1 (9/98), Table 1.1-19, TNMOC for pulverized coal dry bottom furnaces
VOC NG Combustion EF:	5.5	lb/MMscf	AP-42 1.4, Table 1.4-2.

14.5.2 Unit 1 Baseline Actual VOC Emissions

> The monthly coal and NG usage rates during the selected baseline period for Unit 1 are shown in the following table. The baseline actual VOC emissions are calculated based on the respective coal and NG emission factors as shown.

Month	Unit 1 Boiler Coal Usage (tons)	VOC Emissions from Coal (tons)	NG Usage (Mcf)	VOC Emissions from NG (tons)	Total VOC Monthly Emissions (tons)
3/2019	21,074	0.63	458	0.0013	0.63
4/2019	0	0.00	0	0.0000	0.00
5/2019	44,409	1.33	22,541	0.0620	1.39
6/2019	56,145	1.68	6,005	0.0165	1.70
7/2019	71,216	2.14	72	0.0002	2.14
8/2019	68,476	2.05	256	0.0007	2.05
9/2019	67,272	2.02	1,061	0.0029	2.02
10/2019	73,422	2.20	193	0.0005	2.20
11/2019	64,380	1.93	1,925	0.0053	1.94
12/2019	72,906	2.19	21	0.0001	2.19
1/2020	71,262	2.14	2,455	0.0068	2.14
2/2020	66,244	1.99	24	0.0001	1.99
3/2020	59,470	1.78	6,506	0.0179	1.80
4/2020	63,995	1.92	3,612	0.0099	1.93
5/2020	63,359	1.90	128	0.0004	1.90
6/2020	57,413	1.72	3,550	0.0098	1.73
7/2020	65,451	1.96	281	0.0008	1.96
8/2020	64,748	1.94	134	0.0004	1.94
9/2020	55,962	1.68	929	0.0026	1.68
10/2020	67,634	2.03	87	0.0002	2.03
11/2020	62,140	1.86	12	0.0000	1.86
12/2020	62,047	1.86	5,417	0.0149	1.88
1/2021	79,509	2.39	0	0.0000	2.39
2/2021	58,020	1.74	2,489	0.0068	1.75
24-month Total	1,436,554	43.1	58,156	0.1599	43.3
Annual Avg	718,277	21.5	29,078	0.0800	**21.6**

Sample Calculations: (for 12/2020)
VOC Emissions from Coal = 62,047 tons/mo x 0.06 lb/ton / 2,000 lb/ton = 1.86 tons VOC/mo
VOC Emissions from NG = 5,417 MCF/mo / 1000 MCF/MMcf x 5.5 lb/MMscf / 2,000 lb/ton = 0.0149 tons VOC/mo
Total VOC Monthly Emissions = 1.86 + 0.0149 = 1.88 tons VOC/mo
Annual Average Baseline Emissions = 43.3 tons/24-months / 2 years/24-month = 21.6 tpy VOC

14.5.3 Unit 2 Baseline Actual VOC Emissions

> The monthly coal and NG usage rates during the selected baseline period for Unit 2 are shown in the following table. The baseline actual VOC emissions are calculated based on the respective coal and NG emission factors as shown.

Month	Unit 2 Boiler Coal Usage (tons)	VOC Emissions from Coal (tons)	NG Usage (Mcf)	VOC Emissions from NG (tons)	Total VOC Monthly Emissions (tons)
3/2019	73,058	2.19	2,489	0.0068	2.20
4/2019	58,035	1.74	4,367	0.0120	1.75
5/2019	68,309	2.05	56	0.0002	2.05
6/2019	63,042	1.89	958	0.0026	1.89
7/2019	70,568	2.12	163	0.0004	2.12
8/2019	67,333	2.02	0	0.0000	2.02
9/2019	60,312	1.81	3,274	0.0090	1.82
10/2019	73,925	2.22	587	0.0016	2.22
11/2019	72,685	2.18	111	0.0003	2.18
12/2019	68,406	2.05	2,004	0.0055	2.06
1/2020	82,174	2.47	669	0.0018	2.47
2/2020	75,163	2.25	14	0.0000	2.25
3/2020	84,985	2.55	319	0.0009	2.55
4/2020	38,436	1.15	4,810	0.0132	1.17
5/2020	0	0.00	0	0.0000	0.00
6/2020	0	0.00	0	0.0000	0.00
7/2020	0	0.00	0	0.0000	0.00
8/2020	0	0.00	0	0.0000	0.00
9/2020	0	0.00	0	0.0000	0.00
10/2020	0	0.00	7,630	0.0210	0.02
11/2020	66,397	1.99	10,203	0.0281	2.02
12/2020	71,579	2.15	4,223	0.0116	2.16
1/2021	74,209	2.23	3,598	0.0099	2.24
2/2021	58,536	1.76	1,583	0.0044	1.76
24-month Total	1,227,152	36.81	47,058	0.1294	36.9
Annual Avg	613,576	18.41	23,529	0.0647	**18.5**

Sample Calculations: (for 12/2020)
VOC Emissions from Coal = 58,536 tons/mo x 0.06 lb/ton / 2,000 lb/ton = 1.76 tons VOC/mo
VOC Emissions from NG = 1,583 MCF/mo / 1000 MCF/MMcf x 5.5 lb/MMscf / 2,000 lb/ton = 0.0044 tons VOC/mo
Total VOC Monthly Emissions = 1.76 + 0.0044 = 1.76 tons VOC/mo
Annual Average Baseline Emissions = 36.9 tons/24-months / 2 years/24-month = 18.5 tpy VOC

14.6 PM/PM10/PM2.5 Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of PM, PM10, and PM2.5.

14.6.1 PM Emission Factors

> Because there is a PM CEMS on the shared Unit 1 and 2 stack, the baseline actual emissions for filterable PM are known directly from the CEMS data set. The individual unit PM emissions are assumed to be proportional to the individual heat input rate and the total heat input rate.

> LG&E has historically calculated actual PM10 and PM2.5 emissions for Units 1 and 2 for annual emission inventory purposes using the cumulative particle size distribution information for coal boilers in AP-42 Section 1.1 (Bituminous and Subbituminous Coal Combustion), Table 1.1-6, combined with the known PM emissions data from the CEMS.

> Specifically, as shown in AP-42 Table 1.1-6, for a baghouse controlled coal boiler, 92% of cumulative PM filterable mass can be expected to be PM_{10} and 53% of the cumulative PM filterable mass can be expected to be $PM_{2.5}$. These same ratios are also mandated in Table A1, Attachment H of Title V Permit O-0127-20-V.

> Condensable PM emissions from **coal combustion** are estimated based on the emission factor in AP-42 Section 1.1, Table 1.1-6 for pulverized coal boilers with PM control combined with FGD control of 0.02 lb/MMBtu. This emission factor is also mandated in Table A1, Attachment H of Title V Permit O-0127-20-V.

> Condensable PM emissions from **natural gas combustion** are estimated based on the 2011 NEI EPA emission factor, as mandated in Table A2, Attachment H of Title V Permit O-0127-20-V. Note that this attachment of the permit also specifies a PM-filterable emission factor to use for natural gas combustion. However, since all PM (from both coal and natural gas combustion) are measured by the CEMS, a separate calculation of PM-filterable emissions from natural gas combustion is not performed.

PM10/PM Filterable Size Ratio:	0.92	AP-42 1.1 (9/98), Table 1-1-6, Cumulative Mass % for baghouse controlled boiler
PM2.5/PM Filterable Size Ratio:	0.53	AP-42 1.1 (9/98), Table 1-1-6, Cumulative Mass % for baghouse controlled boiler
PM Condensable EF for Coal:	0.02 lb/MMBtu	AP-42 1.1 (9/98), Table 1-1-5, Coal boiler with PM controls combined with FGD
PM Condensable EF for NG:	0.32 lb/MMcf	2011 NEI, EPA (See Attachment H, Table A2 of Title V permit)

14.6.2 Unit 1 Baseline Actual PM/PM10/PM2.5 Emissions

> The monthly coal and natural gas heat input rates during the selected baseline period for Unit 1 are shown in the following table. The baseline actual PM/PM_{10}/$PM_{2.5}$ emissions are calculated based on the PM CEMS data, the PM_{10} and $PM_{2.5}$ filterable ratios, and condensable PM emission factors as shown.

Month	Unit 1 Boiler Coal Heat Input (MMBtu)	Natural Gas Usage (Mcf)	PM Filterable Emissions from CEMS (lb/MMBtu)	PM Filterable Emissions from CEMS (tons)	Condens. PM Emissions (tons)	Total PM Emissions (tons)	PM_{10} Filterable Emissions (tons)	$PM_{2.5}$ Filterable Emissions (tons)
3/2019	472,439	458	0.0041	0.96	4.72	5.68	5.61	5.23
4/2019	0	0	0.0000	0.00	0.00	0.00	0.00	0.00
5/2019	1,027,220	22,541	0.0046	2.34	10.28	12.62	12.43	11.52
6/2019	1,286,599	6,005	0.0043	2.75	12.87	15.62	15.40	14.33
7/2019	1,651,254	72	0.0041	3.40	16.51	19.91	19.64	18.32
8/2019	1,571,795	256	0.0041	3.25	15.72	18.97	18.71	17.44
9/2019	1,550,152	1,061	0.0043	3.34	15.50	18.84	18.57	17.27
10/2019	1,643,911	193	0.0040	3.31	16.44	19.75	19.49	18.19
11/2019	1,419,736	1,925	0.0041	2.92	14.20	17.12	16.89	15.75
12/2019	1,627,665	21	0.0042	3.43	16.28	19.71	19.44	18.10
1/2020	1,565,780	2,455	0.0040	3.17	15.66	18.83	18.57	17.34
2/2020	1,473,879	24	0.0041	3.00	14.74	17.74	17.50	16.33
3/2020	1,241,753	6,506	0.0047	2.93	12.42	15.35	15.11	13.97
4/2020	1,424,207	3,612	0.0043	3.06	14.24	17.30	17.06	15.86
5/2020	1,391,382	128	0.0042	2.91	13.91	16.82	16.59	15.45
6/2020	1,281,102	3,550	0.0042	2.71	12.81	15.52	15.30	14.25
7/2020	1,463,518	281	0.0042	3.11	14.64	17.74	17.49	16.28
8/2020	1,435,575	134	0.0044	3.14	14.36	17.49	17.24	16.02
9/2020	1,257,837	929	0.0043	2.73	12.58	15.31	15.09	14.02
10/2020	1,503,443	87	0.0046	3.44	15.03	18.47	18.20	16.86
11/2020	1,344,464	12	0.0044	2.95	13.44	16.39	16.15	15.01
12/2020	1,354,782	5,417	0.0043	2.90	13.55	16.45	16.22	15.09
1/2021	1,690,775	0	0.0043	3.62	16.91	20.53	20.24	18.83
2/2021	1,219,193	2,489	0.0073	4.43	12.19	16.62	16.27	14.54
24-month Total	31,898,457	58,156		69.80	318.99	388.79	383.21	355.99
Annual Avg	15,949,228	29,078	0.0042	34.90	159.50	**194.4**	**191.6**	**178.0**

Sample Calculations: (for 2/2021)
PM-Filterable Emissions = 1,219,193 MMBtu/mo x 0.0073 lb/MMBtu / 2,000 lb/ton = 4.43 tons/mo PM-Filterable
Condensible PM Emissions = 1,219,193 MMBtu/mo x 0.02 lb/MMBtu / 2,000 lb/ton +
2,489 Mcfmo / 1000 Mcf/MMcf x 0.32 lb/MMcf / 2,000 lb/ton = 12.19 tons/mo PM Condensibles
PM Emissions = 4.43 tons PM-Filt/mo + 12.19 tons PM-Cond/mo = 16.62 tons/mo PM
PM10 Emissions = 4.43 tons PM-Filt/mo x 0.92 + 12.19 tons PM-Cond/mo = 16.27 tons/mo PM10
PM2.5 Emissions = 4.43 tons PM-Filt/mo x 0.53 + 12.19 tons PM-Cond/mo = 14.54 tons/mo PM2.5

Annual Average Baseline PM10 Emissions = 383.2 tons/24-months / 2 years/24-month = 191.6 tpy Total PM10
Annual Average Baseline PM2.5 Emissions = 356.0 tons/24-months / 2 years/24-month = 178.0 tpy Total PM2.5

14.6.3 Unit 2 Baseline Actual PM/PM10/PM2.5 Emissions

> The monthly coal and natural gas heat input rates during the selected baseline period for Unit 2 are shown in the following table. The baseline actual PM/PM_{10}/$PM_{2.5}$ emissions are calculated based on the PM CEMS data, the PM_{10} and $PM_{2.5}$ filterable ratios, and condensable PM emission factors as shown.

Month	Unit 2 Boiler Coal Heat Input (MMBtu)	Natural Gas Usage (Mcf)	PM Filterable Emissions from CEMS (lb/MMBtu)	PM Filterable Emissions from CEMS (tons)	Condens. PM Emissions (tons)	Total PM Emissions (tons)	PM_{10} Filterable Emissions (tons)	$PM_{2.5}$ Filterable Emissions (tons)
3/2019	1,825,052	2,489	0.0041	3.71	18.25	21.96	21.66	20.22
4/2019	1,462,865	4,367	0.0046	3.35	14.63	17.98	17.71	16.41
5/2019	1,567,100	56	0.0045	3.49	15.67	19.16	18.88	17.52
6/2019	1,420,369	958	0.0043	3.03	14.20	17.23	16.99	15.81
7/2019	1,585,589	163	0.0041	3.27	15.86	19.12	18.86	17.59
8/2019	1,529,429	0	0.0041	3.17	15.29	18.46	18.21	16.97
9/2019	1,368,624	3,274	0.0043	2.95	13.69	16.64	16.40	15.25
10/2019	1,635,772	587	0.0040	3.30	16.36	19.65	19.39	18.10
11/2019	1,641,799	111	0.0041	3.37	16.42	19.79	19.52	18.21
12/2019	1,502,585	2,004	0.0042	3.17	15.03	18.20	17.95	16.71
1/2020	1,798,755	669	0.0040	3.64	17.99	21.63	21.33	19.92
2/2020	1,668,024	14	0.0041	3.40	16.68	20.08	19.81	18.48
3/2020	1,798,399	319	0.0046	4.17	17.98	22.15	21.82	20.19
4/2020	853,140	4,810	0.0043	1.84	8.53	10.37	10.22	9.51
5/2020	0	0	0.0000	0.00	0.00	0.00	0.00	0.00
6/2020	0	0	0.0000	0.00	0.00	0.00	0.00	0.00
7/2020	0	0	0.0000	0.00	0.00	0.00	0.00	0.00
8/2020	0	0	0.0000	0.00	0.00	0.00	0.00	0.00
9/2020	0	0	0.0000	0.00	0.00	0.00	0.00	0.00
10/2020	0	7,630	0.0000	0.00	0.00	0.00	0.00	0.00
11/2020	1,433,755	10,203	0.0044	3.16	14.34	17.50	17.25	16.02
12/2020	156,373	4,223	0.0428	3.35	1.56	4.91	4.64	3.34
1/2021	1,579,424	3,598	0.0043	3.39	15.79	19.18	18.91	17.59
2/2021	1,238,756	1,583	0.0073	4.50	12.39	16.89	16.53	14.77
24-month Total	26,065,809	47,058		60.26	260.67	320.92	316.10	292.60
Annual Avg	13,032,905	23,529	0.0049	30.13	130.33	**160.5**	**158.1**	**146.3**

Sample Calculations: (for 22021)
PM-Filterable Emissions = 1,238,756 MMBtu/mo x 0.0073 lb/MMBtu / 2,000 lb/ton = 4.50 tons/mo PM-Filterable
Condensible PM Emissions = 1,238,756 MMBtu/mo x 0.02 lb/MMBtu / 2,000 lb/ton +
1,583 Mcf/mo / 1000 Mcf/MMcf x 0.32 lb/MMcf / 2,000 lb/ton = 12.39 tons/mo PM Condensibles
PM Emissions = 4.50 tons PM-Filt/mo + 12.39 tons PM-Cond/mo = 16.89 tons/mo PM
PM10 Emissions = 4.50 tons PM-Filt/mo x 0.92 + 12.39 tons PM-Cond/mo = 16.53 tons/mo PM10
PM2.5 Emissions = 4.50 tons PM-Filt/mo x 0.53 + 12.39 tons PM-Cond/mo = 14.77 tons/mo PM2.5

Annual Average Baseline PM10 Emissions = 316.1 tons/24-months / 2 years/24-month = 158.1 tpy Total PM10
Annual Average Baseline PM2.5 Emissions = 292.6 tons/24-months / 2 years/24-month = 146.3 tpy Total PM2.5

14.7 Lead Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of lead.

14.7.1 Lead Emission Factors

> Lead emissions from **coal combustion** for Units 1 and 2 calculated for annual emission inventory purposes are based on the emission factor specified in Table A1, Attachment H of Title V Permit O-0127-20-V.

> Lead emissions from **natural gas combustion** for Units 1 and 2 calculated for annual emission inventory purposes are based on the emission factor inf AP-42 Section 1.4 (Natural Gas Combustion), Table 1.4-2 of 5E-4 lb/MMscf. This emission factor is also mandated in Table A2, Attachment H of Title V Permit O-0127-20-V.

Lead Coal Combustion EF:	2.25E-06 lb/MMBtu	Table A1, Attachment H of Title V permit.
Lead NG Combustion EF:	5.00E-04 lb/MMcf	AP-42 1.4, Table 1.4-2

14.7.2 Units 1 and 2 Baseline Actual Lead Emissions

> The monthly coal usage and associated heat input rates, and the natural gas usage rates during the selected baseline period for Unit 1 are shown in the following table. The baseline actual lead emissions are calculated based on the emission factor documented above.

	Unit 1 Boiler				Unit 2 Boiler			
Month	Coal Usage (tons)	Coal Heat Input (MMBtu)	Natural Gas Usage (Mcf)	Lead Emissions (tons)	Coal Usage (tons)	Coal Heat Input (MMBtu)	Natural Gas Usage (Mcf)	Lead Emissions (tons)
3/2019	21,074	472,439	458	0.0005	73,058	1,825,052	2,489	0.0021
4/2019	0	0	0	0.0000	58,035	1,462,865	4,367	0.0016
5/2019	44,409	1,027,220	22,541	0.0012	68,309	1,567,100	56	0.0018
6/2019	56,145	1,286,599	6,005	0.0014	63,042	1,420,369	958	0.0016
7/2019	71,216	1,651,254	72	0.0019	70,568	1,585,589	163	0.0018
8/2019	68,476	1,571,795	256	0.0018	67,333	1,529,429	0	0.0017
9/2019	67,272	1,550,152	1,061	0.0017	60,312	1,368,624	3,274	0.0015
10/2019	73,422	1,643,911	193	0.0018	73,925	1,635,772	587	0.0018
11/2019	64,380	1,419,736	1,925	0.0016	72,685	1,641,799	111	0.0018
12/2019	72,906	1,627,665	21	0.0018	68,406	1,502,585	2,004	0.0017
1/2020	71,262	1,565,780	2,455	0.0018	82,174	1,798,755	669	0.0020
2/2020	66,244	1,473,879	24	0.0017	75,163	1,668,024	14	0.0019
3/2020	59,470	1,241,753	6,506	0.0014	84,985	1,798,399	319	0.0020
4/2020	63,995	1,424,207	3,612	0.0016	38,436	853,140	4,810	0.0010
5/2020	63,359	1,391,382	128	0.0016	0	0	0	0.0000
6/2020	57,413	1,281,102	3,550	0.0014	0	0	0	0.0000
7/2020	65,451	1,463,518	281	0.0016	0	0	0	0.0000
8/2020	64,748	1,435,575	134	0.0016	0	0	0	0.0000
9/2020	55,962	1,257,837	929	0.0014	0	0	0	0.0000
10/2020	67,634	1,503,443	87	0.0017	0	0	7,630	0.0000
11/2020	62,140	1,344,464	12	0.0015	66,397	1,433,755	10,203	0.0016
12/2020	62,047	1,354,782	5,417	0.0015	71,579	156,373	4,223	0.0002
1/2021	79,509	1,690,775	0	0.0019	74,209	1,579,424	3,598	0.0018
2/2021	58,020	1,219,193	2,489	0.0014	58,536	1,238,756	1,583	0.0014
24-month Total	1,436,554	31,898,457	58,156	0.036	1,227,152	26,065,809	47,058	0.029
Annual Avg	718,277	15,949,228	29,078	**0.018**	613,576	13,032,905	23,529	**0.015**

Sample Calculations: (for 2/2021 for Unit 1)
Unit 1 Lead Emissions = 1,219,193 MMBtu/mo x 2.25E-06 lb/MMBtu / 2,000 lb/ton +
2,489 MCF/mo / 1000 Mcf/MMcf x 5.00E-04 lb/MMcf / 2,000 lb/ton = 0.0014 ton/mo
Annual Average Baseline Emissions = 0.036 tons/24-months / 2 years/24-month = 0.018 tpy lead

14.8 CO2e Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of CO2e.

14.8.1 GHG Emission Factors

> Because Units 1 and 2 each have a CO_2 CEMS, the baseline actual emissions are known directly from the CEMS data set. The monthly and overall 24-month annual average baseline actual CO_2 emissions are shown in the table below.

> Emission factors for methane and nitrous oxide from both coal and natural gas combustion are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Table C-2).

> The global warming multiplying factors for CH_4 and N_2O are those specified in 40 CFR 98 Subpart A.

Coal CH_4 Emission Factor:	1.10E-02	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
NG CH_4 Emission Factor:	1.00E-03	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
Coal N_2O Emission Factor:	1.60E-03	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
NG N_2O Emission Factor:	1.00E-04	kg/MMBtu	40 CFR 98 Subpart C, Table C-2

Global warming multiplying factors to calculate CO2e emissions:

GWP for CO_2:	1	40 CFR 98 Subpart A, Table A-1
GWP for CH_4:	25	40 CFR 98 Subpart A, Table A-1
GWP for N_2O:	298	40 CFR 98 Subpart A, Table A-1

14.8.2 Unit 1 Baseline Actual CO2e Emissions

> The monthly coal and NG heat input rates during the selected baseline period for Unit 1 are shown in the following table. The baseline actual CO_2e emissions are calculated based on the directly measured CO_2 emissions and the calculated CH_4 and N_2O emissions as shown.

Month	Unit 1 Boiler Measured CO_2 Emissions (tons)	Coal Heat Input (MMBtu)	NG Heat Input (MMBtu)	CH_4 Emissions (tons)	N_2O Emissions (tons)	CO_2e Emissions (tons)
3/2019	48,034	472,439	488	5.7	0.8	48,425
4/2019	0	0	0	0.0	0.0	0
5/2019	104,290	1,027,220	24,006	12.5	1.8	105,142
6/2019	130,776	1,286,599	6,395	15.6	2.3	131,843
7/2019	167,905	1,651,254	77	20.0	2.9	169,273
8/2019	159,827	1,571,795	273	19.1	2.8	161,130
9/2019	157,472	1,550,152	1,130	18.8	2.7	158,757
10/2019	167,121	1,643,911	206	19.9	2.9	168,484
11/2019	144,355	1,419,736	2,050	17.2	2.5	145,532
12/2019	165,360	1,627,665	22	19.7	2.9	166,709
1/2020	159,199	1,565,780	2,615	19.0	2.8	160,497
2/2020	149,244	1,473,879	26	17.9	2.6	150,465
3/2020	126,756	1,241,753	6,929	15.1	2.2	127,785
4/2020	145,831	1,424,207	3,847	17.3	2.5	147,012
5/2020	142,749	1,391,382	136	16.9	2.5	143,902
6/2020	131,308	1,281,102	3,781	15.5	2.3	132,369
7/2020	150,140	1,463,518	299	17.7	2.6	151,352
8/2020	147,205	1,435,575	143	17.4	2.5	148,394
9/2020	129,030	1,257,837	990	15.3	2.2	130,073
10/2020	153,977	1,503,443	92	18.2	2.7	155,223
11/2020	137,669	1,344,464	13	16.3	2.4	138,783
12/2020	138,950	1,354,782	5,769	16.4	2.4	140,073
1/2021	173,370	1,690,775	0	20.5	3.0	174,771
2/2021	125,040	1,219,193	2,651	14.8	2.2	126,051
24-month Total	3,255,606	31,898,457	61,938	386.9	56.3	3,282,045
Annual Avg	1,627,803	15,949,228	30,969	193.4	28.1	**1,641,022**

Sample Calculations: (for 12/2020)

CH4 Emissions = 1,354,782 MMBtu/mo x 1.10E-02 kg/MMBtu x 2.20462 lb/kg / 2,000 lb/ton + 5,769 MMBtu/mo x 1.00E-03 kg/MMBtu x 2.20462 lb/kg / 2,000 lb/ton = 16.4 tons/mo CH4

N2O Emissions = 1,354,782 MMBtu/mo x 1.60E-03 kg/MMBtu x 2.20462 lb/kg / 2,000 lb/ton + 5,769 MMBtu/mo x 1.00E-04 kg/MMBtu x 2.20462 lb/kg / 2,000 lb/ton = 2.4 tons/mo N2O

CO2e Emissions = 138,950 tons/mo CO2 + (16.4 tons/mo CH4 x 25) + (2.4 tons/mo N2O x 298) = 140,073 tons/mo CO2e
Annual Average Baseline Emissions = 3,282,045 tons/24-months / 2 years/24-month = 1,641,022 tpy CO2e

14.8.3 Unit 2 Baseline Actual CO2e Emissions

> The monthly coal and NG heat input rates during the selected baseline period for Unit 2 are shown in the following table. The baseline actual CO_2e emissions are calculated based on the directly measured CO_2 emissions and the calculated CH_4 and N_2O emissions as shown.

Month	Unit 2 Boiler Measured CO_2 Emissions (tons)	Coal Heat Input (MMBtu)	NG Heat Input (MMBtu)	CH_4 Emissions (tons)	N_2O Emissions (tons)	CO_2e Emissions (tons)
3/2019	185,491	1,825,052	2,651	22.1	3.2	187,003
4/2019	148,459	1,462,865	4,651	17.7	2.6	149,672
5/2019	158,484	1,567,100	60	19.0	2.8	159,783
6/2019	144,195	1,420,369	1,020	17.2	2.5	145,372
7/2019	161,228	1,585,589	174	19.2	2.8	162,542
8/2019	155,520	1,529,429	0	18.5	2.7	156,787
9/2019	139,077	1,368,624	3,487	16.6	2.4	140,211
10/2019	166,320	1,635,772	625	19.8	2.9	167,676
11/2019	166,866	1,641,799	118	19.9	2.9	168,226
12/2019	152,640	1,502,585	2,134	18.2	2.7	153,886
1/2020	182,842	1,798,755	712	21.8	3.2	184,333
2/2020	168,830	1,668,024	15	20.2	2.9	170,212
3/2020	183,695	1,798,399	340	21.8	3.2	185,185
4/2020	87,467	853,140	5,122	10.4	1.5	88,174
5/2020	0	0	0	0.0	0.0	0
6/2020	0	0	0	0.0	0.0	0
7/2020	0	0	0	0.0	0.0	0
8/2020	0	0	0	0.0	0.0	0
9/2020	0	0	0	0.0	0.0	0
10/2020	0	0	8,126	0.0	0.0	0
11/2020	147,080	1,433,755	10,866	17.4	2.5	148,268
12/2020	160,476	156,373	4,497	1.9	0.3	160,606
1/2021	162,020	1,579,424	3,832	19.2	2.8	163,329
2/2021	127,052	1,238,756	1,686	15.0	2.2	128,079
24-month Total	2,797,740	26,065,809	50,116	316.1	46.0	2,819,344
Annual Avg	1,398,870	13,032,905	25,058	158.1	23.0	**1,409,672**

Sample Calculations: (for 2/2021)

CH4 Emissions = 1,238,756 MMBtu/mo x 1.10E-02 kg/MMBtu x 2.20462 lb/kg / 2,000 lb/ton + 1,686 MMBtu/mo x 1.00E-03 kg/MMBtu x 2.20462 lb/kg / 2,000 lb/ton = 15.0 tons/mo CH4

N2O Emissions = 1,238,756 MMBtu/mo x 1.60E-03 kg/MMBtu x 2.20462 lb/kg / 2,000 lb/ton + 1,686 MMBtu/mo x 1.00E-04 kg/MMBtu x 2.20462 lb/kg / 2,000 lb/ton = 2.2 tons/mo N2O

CO2e Emissions = 127,052 tons/mo CO2 + (15.0 tons/mo CH4 x 25) + (2.2 tons/mo N2O x 298) = 128,079 tons/mo CO2e
Annual Average Baseline Emissions = 2,819,344 tons/24-months / 2 years/24-month = 1,409,672 tpy CO2e

15. Mill Creek Unit 1 and 2 Coal Bunkers - Emission Reductions from Shutdowns

> In conjunction with the shutdown of the Unit 1 and 2 boilers, their associated coal silos and coal mills in the coal bunkers will also shutdown resulting in emission decreases of PM that are quantified in this section.

15.1 Coal Bunkers Emission Unit Nomenclature

> The coal silos and coal mills associated with the Unit 1 Boiler operation are designated as Emission Point E2 under Emission Unit U1. Similarly, the coal silos and coal mills associated with the Unit 2 Boiler operation are designated as Emission Point E4 under Emission Unit U2.

Emission Unit	Emission Point	Control Device	Stack ID
U1 - EGU Unit 1	E2 - Four Coal Silos; Four Coal Mills	C3 - Centrifugal Dust Collector	S5
U2 - EGU Unit 2	E4 - Four Coal Silos; Four Coal Mills	C6 - Centrifugal Dust Collector	S6

15.2 PM/PM10/PM2.5 Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of PM, PM10, and PM2.5.

15.2.1 PM Emission Factors

> LG&E has historically calculated uncontrolled PM, PM10 and PM2.5 emissions for the coal bunkers for annual emission inventory purposes using the methodology in AP-42 Section 13.2.4 (Aggregate Handling and Storage Piles).

> PM emissions from transfer points in the process are calculated using Equation 1 of 13.2.4 as a function of material moisture content and mean wind speed. LG&E uses a coal moisture content value of 4.5%, which is the mean value specified for coal-fired power plants in Table 13.2.4-1. Since the coal bunker transfer points are enclosed, a reduced wind speed 1.3 mph is used in the calculation. Particle size multipliers specified in Section 13.2.4 of AP-42 are used to define the PM, PM10, and PM2.5 emission rates. The resulting emission factors used are listed below. These same emission factors are also mandated in Table A3, Attachment H of Title V Permit O-0127-20-V.

$E \text{ (lb/ton)} = 0.0032k * (U/5)^{1.3} / (M/2)^{1.4}$

where:

	PM	PM_{10}	$PM_{2.5}$
k: Particle Size Multiplier (lb/VMT)	0.74	0.35	0.053
M: Material Moisture Content (%)	4.5	4.5	4.5
U: Mean Wind Speed (mph)	1.3	1.3	1.3
E: Emission Factor (lb/ton)	1.32E-04	6.25E-05	9.46E-06

Sample Calculation: (for PM)
PM Transfer EF = 0.0032 x 0.74 x (1.3 /5)^1.3 / (4.5 /2)^1.4 = 1.32E-04 lb/ton

> PM emissions from the coal bunkers are routed to a centrifugal dust collector for control. As specified in Table A3, Attachment H of Title V Permit O-0127-20-V, a 90% control efficiency is used for calculating emissions to the atmosphere.

	PM	PM_{10}	$PM_{2.5}$
Post-Control Emission Factors (lb/ton)	1.32E-05	6.25E-06	9.46E-07

Sample Calculation: (for PM)
Post-Control PM Emission Factor = 1.32E-04 lb/ton x (100% - 90%) = 1.32E-05 lb/ton PM controlled

15.2.2 Unit 1 and 2 Coal Bunker Baseline Actual PM/PM10/PM2.5 Emissions

> The monthly coal usage rates during the selected baseline period for Units 1 and 2 are shown in the following table. The baseline actual PM/PM_{10}/$PM_{2.5}$ emissions are calculated based on PM, PM_{10}, and $PM_{2.5}$ emission factors as shown.

	Unit 1 Coal Handling Emissions				Unit 2 Coal Handling Emissions			
Month	Coal Usage (tons)	PM Filterable Emissions (tons)	PM10 Filterable Emissions (tons)	PM2.5 Filterable Emissions (tons)	Coal Usage (tons)	PM Filterable Emissions (tons)	PM10 Filterable Emissions (tons)	PM2.5 Filterable Emissions (tons)
3/2019	21,074	0.00014	0.00007	0.00001	73,058	0.00048	0.00023	0.00003
4/2019	0	0.00000	0.00000	0.00000	58,035	0.00038	0.00018	0.00003
5/2019	44,409	0.00029	0.00014	0.00002	68,309	0.00045	0.00021	0.00003
6/2019	56,145	0.00037	0.00018	0.00003	63,042	0.00042	0.00020	0.00003
7/2019	71,216	0.00047	0.00022	0.00003	70,568	0.00047	0.00022	0.00003
8/2019	68,476	0.00045	0.00021	0.00003	67,333	0.00044	0.00021	0.00003
9/2019	67,272	0.00044	0.00021	0.00003	60,312	0.00040	0.00019	0.00003
10/2019	73,422	0.00048	0.00023	0.00003	73,925	0.00049	0.00023	0.00003
11/2019	64,380	0.00043	0.00020	0.00003	72,685	0.00048	0.00023	0.00003
12/2019	72,906	0.00048	0.00023	0.00003	68,406	0.00045	0.00021	0.00003
1/2020	71,262	0.00047	0.00022	0.00003	82,174	0.00054	0.00026	0.00004
2/2020	66,244	0.00044	0.00021	0.00003	75,163	0.00050	0.00023	0.00004
3/2020	59,470	0.00039	0.00019	0.00003	84,985	0.00056	0.00027	0.00004
4/2020	63,995	0.00042	0.00020	0.00003	38,436	0.00025	0.00012	0.00002
5/2020	63,359	0.00042	0.00020	0.00003	0	0.00000	0.00000	0.00000
6/2020	57,413	0.00038	0.00018	0.00003	0	0.00000	0.00000	0.00000
7/2020	65,451	0.00043	0.00020	0.00003	0	0.00000	0.00000	0.00000
8/2020	64,748	0.00043	0.00020	0.00003	0	0.00000	0.00000	0.00000
9/2020	55,962	0.00037	0.00017	0.00003	0	0.00000	0.00000	0.00000
10/2020	67,634	0.00045	0.00021	0.00003	0	0.00000	0.00000	0.00000
11/2020	62,140	0.00041	0.00019	0.00003	66,397	0.00044	0.00021	0.00003
12/2020	62,047	0.00041	0.00019	0.00003	71,579	0.00047	0.00022	0.00003
1/2021	79,509	0.00053	0.00025	0.00004	74,209	0.00049	0.00023	0.00004
2/2021	58,020	0.00038	0.00018	0.00003	58,536	0.00039	0.00018	0.00003
24-month Total	1,436,554	0.0095	0.0045	0.0007	1,227,152	0.0081	0.0038	0.0006
Annual Avg	718,277	**0.0047**	**0.0022**	**0.0003**	613,576	**0.0041**	**0.0019**	**0.0003**

Sample Calculations: (for 2/2021 for Unit 1 for PM)
Unit 1 Coal Bunker PM Emissions = 58,020 tons x 1.32-E-05 lb/ton / 2,000 lb/ton = 0.00038 tons/mo PM
Annual Average Baseline PM Emissions for Unit 1 Coal Bunker = 0.0095 tons/24-months / 2 years/24-month = 0.0047 tpy PM

16. Mill Creek Unit 1 and 2 Coal Bunkers - Emission Reductions from Shutdowns

> The shutdown of Unit 1 and 2 boilers as part of the NGCC project will result in emission reductions from the corresponding shutdown of their associated coal handling operations.

16.1 Coal Handling Operations Emission Unit Nomenclature

> The coal handling operations associated with the coal boilers are covered by Emission Unit 21 (Emission Points E47a-f). While the coal handling operations will remain following the project, their emissions will decrease given the reduction in coal throughput from the shutdown of Units 1 and 2. The emission reductions associated with the shutdown of Units 1 and 2 can be quantified based on the coal throughput attributable to the Unit 1 and 2 boilers during the baseline period.

Emission Unit	Emission Point	Transfer Enclosure
U21 - Coal Handling	E47a - Barge Unloading Operation (Coal)	Outdoors
U21 - Coal Handling	E47b - Railcar Unloading (Coal)	Outdoors
U21 - Coal Handling	E47c - Coal Radial Stacker	Outdoors
U21 - Coal Handling	E47d - Two Coal Crushers	Indoor/Enclosed
U21 - Coal Handling	E47e1-16 - Coal Belt Conveyors	Indoor/Enclosed
U21 - Coal Handling	E47f - Coal Storage Pile (Drop Point Emission)	Outdoors

16.2 PM/PM10/PM2.5 Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of PM, PM10, and PM2.5.

16.2.1 PM Emission Factors

> LG&E has historically calculated actual PM, PM10, and PM2.5 emissions for the coal handling operations for annual emission inventory purposes using the methodology in AP-42 Section 13.2.4 (Aggregate Handling and Storage Piles).

> PM emissions from transfer points in the coal handling operations are calculated using Equation 1 of 13.2.4 as a function of material moisture content and mean wind speed. LG&E uses a coal moisture content value of 4.5%, which is the mean value specified for coal-fired power plants in Table 13.2.4-1. A wind speed of 8.4 and 1.3 mph is used for indoor/enclosed and outdoor transfer points, respectively. Particle size multipliers specified in the 13.2.4 of AP-42 are used to define the PM, PM10, and PM2.5 emission rates. The resulting emission factors used for each type of transfer are listed below. These same emission factors are also mandated in Table A3, Attachment H of Title V Permit O-0127-20-V.

$E\ (\text{lb/ton}) = 0.0032k * (U/5)^{1.3} / (M/2)^{1.4}$ where:

	PM	PM_{10}	$PM_{2.5}$
k: Particle Size Multiplier (lb/VMT)	0.74	0.35	0.053
M: Material Moisture Content (%)	4.5	4.5	4.5
Emission Factors for Outdoor Transfers (E47a, E47b, E47c, and E47f)			
U: Mean Wind Speed (mph)	8.4	8.4	8.4
E: Emission Factor (lb/ton)	1.49E-03	7.06E-04	1.07E-04
Emission Factors for Indoor/Enclosed Transfers (E47d and E47e)			
U: Mean Wind Speed (mph)	1.3	1.3	1.3
E: Emission Factor (lb/ton)	1.32E-04	6.25E-05	9.46E-06

Sample Calculation: (for PM for Outdoor Transfer)
PM Outdoor Transfer EF = 0.0032 x 0.74 x (8.4 /5)^1.3 / (4.5 /2)^1.4 = 1.49E-03 lb/ton

> A single consolidated emission factor for each PM size fraction is calculated based on the sum of transfer points. The barge and rail car unloading emission factors, which are identical, are only counted once since coal is only received via one of the two methods at a time.

	PM	PM_{10}	$PM_{2.5}$
Combined Emission Factor (lb/ton)	4.74E-03	2.24E-03	3.40E-04

Sample Calculation (for PM):
Coal Handling PM EF = 1.49E-03 (barge/rail unloading) + 1.49E-03 (radial stacker) + 1.49E-03 (coal pile) + 1.32E-04 (conveyors) + 1.32E-04 (coal crusher) = 4.74E-03 lb/ton PM

16.2.2 Unit 1 and 2 Coal Handling Operations Baseline Actual PM/PM10/PM2.5 Emissions

> The monthly coal usage rates during the selected baseline period for Units 1 and 2 are shown in the following table. The baseline actual emissions are calculated based on PM, PM_{10}, and $PM_{2.5}$ emission factors as shown.

	Unit 1 Coal Handling Emissions				Unit 2 Coal Handling Emissions			
Month	Coal Usage (tons)	PM Filterable Emissions (tons)	PM10 Filterable Emissions (tons)	PM2.5 Filterable Emissions (tons)	Coal Usage (tons)	PM Filterable Emissions (tons)	PM10 Filterable Emissions (tons)	PM2.5 Filterable Emissions (tons)
3/2019	21,074	0.050	0.024	0.004	73,058	0.173	0.082	0.012
4/2019	0	0.000	0.000	0.000	58,035	0.138	0.065	0.010
5/2019	44,409	0.105	0.050	0.008	68,309	0.162	0.077	0.012
6/2019	56,145	0.133	0.063	0.010	63,042	0.150	0.071	0.011
7/2019	71,216	0.169	0.080	0.012	70,568	0.167	0.079	0.012
8/2019	68,476	0.162	0.077	0.012	67,333	0.160	0.076	0.011
9/2019	67,272	0.160	0.075	0.011	60,312	0.143	0.068	0.010
10/2019	73,422	0.174	0.082	0.012	73,925	0.175	0.083	0.013
11/2019	64,380	0.153	0.072	0.011	72,685	0.172	0.082	0.012
12/2019	72,906	0.173	0.082	0.012	68,406	0.162	0.077	0.012
1/2020	71,262	0.169	0.080	0.012	82,174	0.195	0.092	0.014
2/2020	66,244	0.157	0.074	0.011	75,163	0.178	0.084	0.013
3/2020	59,470	0.141	0.067	0.010	84,985	0.202	0.095	0.014
4/2020	63,995	0.152	0.072	0.011	38,436	0.091	0.043	0.007
5/2020	63,359	0.150	0.071	0.011	0	0.000	0.000	0.000
6/2020	57,413	0.136	0.064	0.010	0	0.000	0.000	0.000
7/2020	65,451	0.155	0.073	0.011	0	0.000	0.000	0.000
8/2020	64,748	0.154	0.073	0.011	0	0.000	0.000	0.000
9/2020	55,962	0.133	0.063	0.010	0	0.000	0.000	0.000
10/2020	67,634	0.160	0.076	0.011	0	0.000	0.000	0.000
11/2020	62,140	0.147	0.070	0.011	66,397	0.158	0.075	0.011
12/2020	62,047	0.147	0.070	0.011	71,579	0.170	0.080	0.012
1/2021	79,509	0.189	0.089	0.014	74,209	0.176	0.083	0.013
2/2021	58,020	0.138	0.065	0.010	58,536	0.139	0.066	0.010
24-month Total	1,436,554	3.41	1.61	0.24	1,227,152	2.91	1.38	0.21
Annual Avg	718,277	**1.70**	**0.81**	**0.12**	613,576	**1.46**	**0.69**	**0.10**

Sample Calculations: (for 2/2021 for Unit 1 for PM)
Unit 1 Coal Handling PM Emissions = 58,020 tons x 4.74-E-03 lb/ton / 2000 lb/ton = 0.138 tons/mo PM
Annual Average Baseline PM Emissions for Unit 1 Coal Handling = 3.41 tons/24-months / 2 years/24-month = 1.70 tpy PM

17. Mill Creek Unit 1 and 2 Flyash Transfer Bin - Emission Reductions from Shutdowns

> In conjunction with the shutdown of the Unit 1 and 2 boilers, the Flyash Transfer Bin for Units 1 and 2 will also shutdown resulting in emission decreases of PM that are quantified in this section.

17.1 Flyash Transfer Bin Emission Unit Nomenclature

> The flyash transfer bin serving the Units 1 and 2 Boilers is designated as Emission Point E16 under Emission Unit U9. While Emission Unit U9 will remain, E16 will be removed as part of the NGCC project.

Emission Unit	Emission Point	Control Device	Stack ID
U9 - Fly Ash Transfer Bins	E16 - Flyash Transfer Bin with Two Separators for Units 1 & 2	C19 - Baghouse	S17, S24, S25

17.2 PM/PM10/PM2.5 Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of PM, PM10, and PM2.5.

17.2.1 PM Emission Factors

> LG&E has historically calculated uncontrolled PM, PM10 and PM2.5 emissions for the flyash transfer bins using representative emission factors in AP-42 Section 11.12 (Concrete Batching), Table 11.12-2 for cement supplement unloading to an elevated silo.

> To account for the higher moisture content in coal flyash (4.8%) versus cement supplement (1%), the Table 11.12-2 emission factors are multiplied by the moisture content adjustment factor from AP-42 Section 13.2.4 Equation 1 (for aggregate drop points). The resulting uncontrolled emission factors are also what is listed in Table A3 of Attachment H in Title V Permit O-0127-20-V.

Moisture Content Adjustment Factor = (1%)^1.4 / (4.8%)^1.4 = 0.1112

	PM	PM_{10}
Emission factors from Table 11.12-2 (lb/ton)	3.14	1.1
Adjusted for Coal Flyash Moisture (lb/ton)	0.3493	0.1224

<u>Sample Calculation</u>: (for PM)
Coal Flyash Transfer EF = 3.14 lb/ton for cement unloading x 0.1112 moisture adjustment factor = 0.3493 lb/ton PM

> Because there is not a separate $PM_{2.5}$ emission factor available in AP-42 Table 11.12-2, $PM_{2.5}$ emissions have historically been set equal to PM_{10} for emission inventory purposes.

> PM emissions from the flyash transfer bin are routed to a baghouse for PM control. As specified in Table A3, Attachment H of Title V Permit O-0127-20-V, a 98% control efficiency is used for calculating emissions to the atmosphere.

	PM	PM_{10}
Post-Control Emission Factors (lb/ton)	6.99E-03	2.45E-03

<u>Sample Calculation</u>: (for PM)
Post-Control PM Emission Factor = 0.3493 lb/ton x (1 - 0.98) = 6.99E-03 lb/ton PM controlled

17.2.2 Unit 1 & 2 Flyash Transfer Bin Baseline Actual PM/PM10/PM2.5 Emissions

> The emission factors defined above are multiplied by the flyash throughput rate to define emissions. The amount of flyash generated is calculated as 80% of the total ash content in the coal.

> The monthly coal usage rates during the selected baseline period for Units 1 and 2 along with ash contents and calculated flyash process rates are shown in the following table. The baseline actual PM/PM_{10}/$PM_{2.5}$ emissions are calculated based on PM and PM_{10} emission factors as shown.

Month	Unit 1 Coal Usage (tons)	Unit 1 Coal Ash Content (%)	Unit 2 Coal Usage (tons)	Unit 2 Coal Ash Content (%)	Total Unit 1& 2 Flyash (tons)	PM Filterable Emissions (tons)	PM10 Filterable Emissions (tons)	PM2.5 Filterable Emissions (tons)
3/2019	21,074	8.96%	73,058	9.03%	6,788	0.02371	0.00831	0.00831
4/2019	0	0.00%	58,035	8.97%	4,165	0.01455	0.00510	0.00510
5/2019	44,409	9.11%	68,309	9.08%	8,198	0.02864	0.01003	0.01003
6/2019	56,145	9.29%	63,042	9.28%	8,853	0.03092	0.01083	0.01083
7/2019	71,216	9.33%	70,568	9.33%	10,583	0.03697	0.01295	0.01295
8/2019	68,476	9.42%	67,333	9.43%	10,240	0.03577	0.01253	0.01253
9/2019	67,272	9.15%	60,312	9.13%	9,329	0.03259	0.01142	0.01142
10/2019	73,422	9.40%	73,925	9.40%	11,080	0.03870	0.01356	0.01356
11/2019	64,380	9.70%	72,685	9.71%	10,642	0.03717	0.01302	0.01302
12/2019	72,906	9.75%	68,406	9.76%	11,028	0.03852	0.01349	0.01349
1/2020	71,262	9.78%	82,174	9.78%	12,005	0.04193	0.01469	0.01469
2/2020	66,244	9.86%	75,163	9.86%	11,154	0.03896	0.01365	0.01365
3/2020	59,470	9.97%	84,985	9.97%	11,522	0.04024	0.01410	0.01410
4/2020	63,995	9.94%	38,436	9.95%	8,148	0.02846	0.00997	0.00997
5/2020	63,359	10.02%	0	0.00%	5,079	0.01774	0.00621	0.00621
6/2020	57,413	10.09%	0	0.00%	4,634	0.01619	0.00567	0.00567
7/2020	65,451	10.21%	0	0.00%	5,346	0.01867	0.00654	0.00654
8/2020	64,748	10.28%	0	0.00%	5,325	0.01860	0.00652	0.00652
9/2020	55,962	10.40%	0	0.00%	4,656	0.01626	0.00570	0.00570
10/2020	67,634	10.35%	0	0.00%	5,600	0.01956	0.00685	0.00685
11/2020	62,140	10.41%	66,397	10.41%	10,705	0.03739	0.01310	0.01310
12/2020	62,047	10.43%	71,579	10.44%	11,155	0.03897	0.01365	0.01365
1/2021	79,509	10.37%	74,209	10.37%	12,752	0.04454	0.01560	0.01560
2/2021	58,020	10.29%	58,536	10.29%	9,595	0.03351	0.01174	0.01174
24-month Total	1,436,554				208,584	0.729	0.255	0.255
Annual Avg	718,277				104,292	**0.364**	**0.128**	**0.128**

Sample Calculations: (for 2/2021 for Unit 1 for PM)
Total Unit 1 & 2 Flyash = 80% x (58,020 tons x 10.29% + 58,536 tons x 10.29%) = 9,595 tons/mo flyash
PM Filterable Emissions = 9,595 tons flyash/mo x 6.99E-03 lb/ton / 2,000 lb/ton = 0.03351 tons/mo PM
Annual Average Baseline PM Emissions for Flyash Transfer = 0.729 tons/24-months / 2 years/24-month = 0.364 tpy PM

18. Mill Creek Unit 1 and 2 Sorbent and PAC Silos - Emission Reductions from Shutdowns

> In conjunction with the shutdown of the Unit 1 and 2 boilers, two of the six existing Sorbent Silos (U16) used for holding dry sorbent or Trona will be shutdown. Similarly, two of the six existing PAC Storage Silos (U17) associated with the PAC Injection Systems will also shutdown. The remaining four Sorbent Silos and PAC Silos will continue to operate to serve Units 3 and 4 and will be unaffected by the project. The small level of PM emission reductions associated with the shutdown of two of the Sorbent Silos and PAC Silos are quantified in this section.

18.1 Sorbent and PAC Silos Emission Unit Nomenclature

> All six Sorbent Silos serving the Units 1 to 4 Boilers are designated as Emission Unit U16 and are individually Emission Points E40a to E40f. Sorbent Silos E40a and E40b will be shutdown and the remaining E40c to E40f Silos will remain.

> All six PAC Silos serving the Units 1 to 4 Boilers are designated as Emission Unit U17 and are individually Emission Points E41a to E41f. PAC Silos E41a and E41b will be shutdown and the remaining E41c to E41f Silos will remain.

Emission Unit	Emission Point	Control Device	Stack ID
Emission Points Shutting Down with NCGG Project			
U16 - Sorbent Storage Silos	E40a-b - Two of Six Sorbent Silos for Dry Sorbent or Trona	C32a-b - Bin Vent Filters	S35a-b
U17 - PAC Storage Silos	E41a-b - Two of Six PAC Silos for PAC Injection System	C33a-b - Bin Vent Filters	S36a-b
Emission Points Remaining to Serve Units 3 and 4 Boilers			
U16 - Sorbent Storage Silos	E40c-f - Four of Six Sorbent Silos for Dry Sorbent or Trona	C32c-f - Bin Vent Filters	S35c-f
U17 - PAC Storage Silos	E41c-f - Four of Six PAC Silos for PAC Injection System	C33c-f - Bin Vent Filters	S36c-f

18.2 PM/PM10/PM2.5 Baseline Actual Emissions

> LG&E has selected the 24-month period ending February 2021 for defining baseline actual emissions of PM, PM10, and PM2.5.

18.2.1 PM Emission Factors

> LG&E has historically calculated uncontrolled PM, PM10 and PM2.5 emissions for transfers to the Sorbent and PAC Silos using representative emission factors in AP-42 Section 11.17 (Lime Manufacturing), Table 11.17.4 for product loading operations, of 0.61 lb/ton. This emission factor is also mandated in Table A3, Attachment H of Title V Permit O-0127-20-V.

> The Sorbent and PAC Silos are each equipped with bin vent filter systems that provide control of PM emissions. As specified in Attachment G of Title V Permit O-0127-20-V, a 99% control efficiency is used for calculating emissions to the atmosphere based on data provided by the filter manufacturer. Given the presence of the PM filter, all PM is assumed to be in the $PM_{2.5}$ size fraction.

Emission factor from Table 11.17-4	0.61	lb/ton
Bin Vent Filter Control Efficiency	99%	
Controlled Emission Factor for Silos	0.0061	lb/ton (for PM, PM10, PM2.5)

18.2.2 Unit 1 & 2 Sorbent and PAC Silos Baseline Actual PM/PM10/PM2.5 Emissions

> LG&E tracks annual throughput rates of sorbent and PAC used in total. Throughput rates for the two of six silos being shutdown are calculated as 1/3 of the total. A reasonable estimate of the monthly throughput rates in the silos for each month in 2019 to 2021 during the baseline period were made by apportioning the annual process rate based on monthly operating hours. The baseline actual PM/PM10/PM2.5 emissions are calculated based on emission factors shown and these throughput rates.

	Sorbent Silos			PAC Silos		
	Total Sorbent Throughput (tons)	E40a & E40b Silos Sorbent Throughput (tons)	PM/PM10/ PM2.5 Filterable Emissions (tons)	Total PAC Throughput (tons)	E41a & E41b PAC Throughput	PM/PM10/ PM2.5 Filterable Emissions (tons)
Year						
2019	13,419	4,473	0.014	501	167	0.0005
2020	10,963	3,654	0.011	311	104	0.0003
2021	12,729	4,243	0.013	388	129	0.0004
Month						
3/2019	729	243	7.41E-04	27.2	9.1	2.77E-05
4/2019	468	156	4.75E-04	17.5	5.8	1.78E-05
5/2019	1,137	379	1.16E-03	42.4	14.1	4.31E-05
6/2019	1,221	407	1.24E-03	45.6	15.2	4.64E-05
7/2019	1,312	437	1.33E-03	49.0	16.3	4.98E-05
8/2019	1,312	437	1.33E-03	49.0	16.3	4.98E-05
9/2019	1,170	390	1.19E-03	43.7	14.6	4.44E-05
10/2019	1,310	437	1.33E-03	48.9	16.3	4.97E-05
11/2019	1,159	386	1.18E-03	43.3	14.4	4.40E-05
12/2019	1,196	399	1.22E-03	44.7	14.9	4.54E-05
1/2020	1,315	438	1.34E-03	37.3	12.4	3.79E-05
2/2020	1,236	412	1.26E-03	35.1	11.7	3.56E-05
3/2020	1,188	396	1.21E-03	33.7	11.2	3.42E-05
4/2020	995	332	1.01E-03	28.2	9.4	2.87E-05
5/2020	659	220	6.70E-04	18.7	6.2	1.90E-05
6/2020	569	190	5.78E-04	16.1	5.4	1.64E-05
7/2020	625	208	6.36E-04	17.7	5.9	1.80E-05
8/2020	657	219	6.68E-04	18.7	6.2	1.90E-05
9/2020	565	188	5.75E-04	16.0	5.3	1.63E-05
10/2020	660	220	6.71E-04	18.7	6.2	1.90E-05
11/2020	1,189	396	1.21E-03	33.7	11.2	3.43E-05
12/2020	1,307	436	1.33E-03	37.1	12.4	3.77E-05
1/2021	1,643	548	1.67E-03	50.1	16.7	5.09E-05
2/2021	1,126	375	1.15E-03	34.3	11.4	3.49E-05
24-month Total	24,745	8,248	0.025		269	0.0008
Annual Avg	12,373	4,124	**0.013**		134	**0.0004**

Sample Calculations: (for 12/2020 for Sorbent Silos)
E40a & E40b Sorbent Throughput = 1,307 tons/mo x 2 / 6 silos = 0,436 tons/mo
PM Emissions = 436 tons/mo x 0.0061 lb/ton / 2,000 lb/ton = 0.0013 tons/mo PM
Annual Average Baseline PM Emissions = 0.025 tons/24-months / 2 years/24-month = 0.013 tpy PM

19. Mill Creek Unit 2 Cooling Tower - Emission Reductions from Shutdown

> In conjunction with the shutdown of the Unit 1 and 2 boilers, the Cooling Tower serving Unit 2 will also shutdown resulting in emission decreases of PM that are quantified in this section.

19.1 Unit 2 Cooling Tower Nomenclature and Specifications

> The existing cooling tower serving the Unit 2 Boiler is currently designated as an insignificant activity in the Title V permit.

Emission Unit	**IA5 - Other Insignificant Activities**
Emission Point	IE14a - Cooling Tower for Unit 2

19.2 Methodology for Defining Baseline PM Emissions from Cooling Tower

19.2.1 PM Emission Factor

> As the water flows down through a cooling tower, the draft air picks up water droplets that can be emitted from the top of the tower (i.e., "drift loss"). Drift loss is minimized through the use of mist eliminators. Particulate matter emissions can result due to the presence of dissolved solids in the cooling tower water droplets that are released from the tower. As the cooling tower droplets disperse in the atmosphere, the liquid water evaporates, leaving behind solid particles in the form of particulate matter.

> Particulate matter emissions from cooling towers are estimated using the procedures of AP-42 Section 13.4 (1/1995 edition), in which PM emissions are estimated as a function of the tower flow capacity, drift loss, and total dissolved solids (TDS) in the cooling tower recirculating water.

> For 2019, 2020, and 2021, LG&E used a 150,000 gpm recirculation rate in the Unit 2 cooling tower. The nominal average TDS content of the recirculating water is 479 ppm. These values are used to define the baseline actual PM emissions.

> As specified in Table A.5 of Title V Permit O-0127-20-V, the drift loss% specification for the Unit 2 cooling tower is 0.00002%.

Circulating Water Flow Rate	150,000	gpm	
	9.0	MMgal/hr	150,000 gpm x 60 min/hr / 1E6 = 9.0 MMgal/hr
Total Dissolved Solids (TDS) of Recirculating Water	479	ppm	
Drift Percentage for Cooling Tower Mist Eliminator	0.00002	%	
Density of Circulating Water	8.34	lb/gal	

PM emission factor based on AP42 13.4 methodology:

PM Factor = 2.0E-07 gal drift/gal flow x 8.34 lb/gal x 479 ppm = 0.000799 lb/MMgal

19.2.2 PM10 and PM2.5 Emission Factors

> PM_{10} and $PM_{2.5}$ emission factors are derived from the PM emission factor calculated above using the methodology presented in "Calculating Realistic PM_{10} Emissions from Cooling Towers" by Joe Reisman and Gordon Frisbie, Environmental Progress, Volume 21, Issue 2 (April 20, 2004).

> The aerodynamic diameter of a particle resulting from drift was calculated over a target droplet size distribution presented in the table below, taken from the source cited above. By interpolating on the calculated aerodynamic particle diameter, the corresponding mass percentage smaller than $PM_{2.5}$ and PM_{10} can be derived.

Droplet Diameter Size[1] (µm)	EPRI % Mass Smaller[1] (%)	Droplet Volume (µm³)	Droplet Mass (µg)	Particle Mass (Solids) (µg)	Solid Particle Volume (µm³)	Solid Particle Diameter (µm)	Aerodyn. Particle Diameter (µm)
10	0	524	5.24E-04	2.51E-07	0.11	0.60	0.9
20	0.196	4,189	4.19E-03	2.01E-06	0.91	1.20	1.8
28.0	***0.220***	***11,515***	***1.15E-02***	5.52E-06	***2.51***	1.69	***2.5***
30	0.226	14,137	0.01	6.77E-06	3.08	1.80	2.7
40	0.514	33,510	0.03	1.61E-05	7.30	2.41	3.6
50	1.816	65,450	0.07	3.14E-05	14.25	3.01	4.5
60	5.702	113,097	0.11	5.42E-05	24.62	3.61	5.4
70	21.348	179,594	0.18	8.60E-05	39.10	4.21	6.2
90	49.812	381,704	0.38	1.83E-04	83.11	5.41	8.0
110	70.509	696,910	0.70	3.34E-04	152	6.62	9.8
112.1	***71.700***	***736,973***	***0.74***	3.53E-04	***160.46***	6.74	***10.0***
130	82.023	1,150,347	1.15	5.51E-04	250	7.82	11.6
150	88.012	1,767,146	1.77	8.46E-04	385	9.02	13.4
180	91.032	3,053,628	3.05	1.46E-03	665	10.83	16.1
210	92.468	4,849,048	4.85	2.32E-03	1,056	12.63	18.7
240	94.091	7,238,229	7.24	3.47E-03	1,576	14.44	21.4
270	94.689	10,305,995	10.31	4.94E-03	2,244	16.24	24.1
300	96.288	14,137,167	14.14	6.77E-03	3,078	18.05	26.8
350	97.011	22,449,298	22.45	1.08E-02	4,888	21.06	31.2
400	98.340	33,510,322	33.51	1.61E-02	7,296	24.06	35.7
450	99.071	47,712,938	47.71	2.29E-02	10,388	27.07	40.2
500	99.071	65,449,847	65.45	3.14E-02	14,250	30.08	44.6
600	100	113,097,336	113.10	5.42E-02	24,624	36.10	53.5

Bold highlights indicate interpolated values to determine PM_{10} and $PM_{2.5}$ size fractions.

[1] Based on drift droplet size distribution testing from EPRI test facility published in the Reisman and Frisbie paper.

Estimated PM_{10}/PM Ratio	0.717	EPRI ratio of mass smaller than PM_{10} (based on interpolation in table above)
Estimated $PM_{2.5}$/PM Ratio	2.20E-03	EPRI ratio of mass smaller than $PM_{2.5}$ (based on interpolation in table above)

Pollutant	Emission Factor (lb/MMgal)	Basis
PM	0.000799	
PM_{10}	0.000573	= 0.000799 lb PM/MMgal circulating water x 0.717 Estimated PM10/PM Ratio
$PM_{2.5}$	1.76E-06	= 0.000799 lb PM/MMgal circulating water x 2.20E-03 Estimated PM2.5/PM Ratio

19.3 Unit 2 Cooling Tower Baseline Actual Emissions

Pollutant	Emission Factor (lb/MMgal)	Basis	Baseline Period Recirc. Rate (MMgal/hr)	BAE (tpy)
PM	0.000799	479 ppm TDS in recirculating water and 0.00002% drift	9.0	0.031
PM_{10}	0.000573	EPRI PM_{10}/PM ratio	9.0	0.023
$PM_{2.5}$	1.758E-06	EPRI $PM_{2.5}$/PM ratio	9.0	6.9E-05

<u>Sample Calculations</u>:
PM (tpy) = 0.00080 lb/MMgal x 9.0 MMgal/hr x 8,760 hr/yr / 2,000 lb/ton = 0.031 tpy PM

APPENDIX C. AIR PERMIT APPLICATION FORMS

The following APCD air permit application forms are included with this permit application:

1. Form AP-100A – Administrative Information
2. Form AP-100B – Emission Unit Definition (5)
3. Form AP-100C – Emissions Data
4. Form AP-100D – Stack Data (4)
5. Form AP-100E – Emission Calculations
6. Form AP-100H – Applicable Requirements (3)
7. Form AP-100J – Compliance Monitoring (3)
8. Form AP-100N – Episode Standby Plan
9. Form AP-100P – Insignificant Activities
10. Form AP-200E – Combustion Source (2)
11. Form AP-200J – Generator or Engine (3)
12. Form AP-300A – Generic Control Equipment (for GT/DB Oxidation Catalyst)
13. Form AP-300G – Reducing System (for GT/DB SCR)

The Acid Rain Program revision application covering the NGCC Project is also provided in this appendix following the application forms.

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100A

Administrative Information

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

In accordance with District regulation 2.03, section 1, you may not install, modify, or operate an affected facility unless a permit has been issued by the District. Please complete all requested information in this application and associated attachments. Incomplete applications may result in denial of issuing a permit to construct or operate the affected facility.

Type of Application

☑ **Construction**	Proposed date to start construction: 03/2024	☑ **Operating**	☐ **Renewal**
☐ **Update :**	Date of original application submission:		
Administrative Change :	☐ RO Change (pg. 5)	☐ Address/Contact information	☐ Owner or Operator
Modification/Revision :	☑ Major	☐ Minor	
Source Category:	☑ Major (Title V)	☐ FEDOOP ☐ FEDOOP, STAR Exempt	☐ Minor
Date of application submission:	12/15/2022		

To apply as an Exempt or Registered source, submit Form **AP-500A** rather than this form.

Source Information

Plant (Facility) name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Plant street address:	14460 Dixie Highway		
City:	Louisville	ZIP + 4:	40272
Primary Source Industrial Classification (SIC) No.:	4911 **OR**	Primary NAICS No.:	221112
KY Secretary of State Organization number:	32196		
Nature of business:	Generation of electricity for local and remote distribution		
Nature of surrounding area:	☑ Residential ☐ Industrial ☐ Commercial	☐ Rural	☑ Urban

Applicant Information

Name:	Alex Betz	Title: (if an individual)	General Manager
Address:	14460 Dixie Highway		
City:	Louisville	State: KY	ZIP + 4: 40272

Applicant is: ☐ Owner ☐ Operator ☑ Owner& Operator ☐ Corporation/LLC ☐ LP

- **If the applicant is a Corporation or a Limited Liability Corporation, submit a copy of the current Certificate of Authority from the Kentucky Secretary of State.**
- **If the applicant is a Limited Partnership, submit a copy of the current Certificate of Limited Partnership from the Kentucky Secretary of State.**

☑ **Certificate has not changed since last submission on** 02 / 16 /20 16 . (a new certificate is not required.)

Applicants agent (if applicable):

Applicant or agent e-mail: alex.betz@lge-ku.com   Applicant or agent phone: (502) 933-6534

Owner Information (same as applicant ☑)			
Name:		Title:	
Address:			
City:		State:	ZIP + 4:
e-mail:			Phone:

Operation Information (same as applicant ☑)			
Name:		Title:	
Address:			
City:		State:	ZIP + 4:
e-mail:			Phone:

Responsible Official (same as applicant ☐)			
Name: Steven Turner		Title: VP Power Production	
Address: 220 W. Main Street			
City: Louisville		State: KY	ZIP + 4: 40202
e-mail: steven.turner@lge-ku.com			Phone:

Environmental Contact (same as ☐ owner ☐ operator ☐ applicant)			
Name: Brandan Burfict		Title: Environmental Engineer	
Address: 220 W. Main Street			
City: Louisville		State: KY	ZIP + 4: 40202
e-mail: Brandan.Burfict@lge-ku.com			Phone: (502) 627-2791

Billing Contact (same as ☐ owner ☐ operator ☐ applicant ☑ environmental)			
Name:		Title:	
Address:			
City:		State:	ZIP + 4:
e-mail:			Phone:

Brief description of project, or reason for application
LG&E plans to install a new natural gas-fired combined-cycle turbine and supporting processes. Existing coal-fired EGUs Units 1 and Unit 2 are being retired and the new NGCC Unit is being constructed to replace their capacity.

Application Documents

Check all other forms which are attached as part of this application, indicating the number of copies, if multiple:

Forms marked with an * are **REQUIRED** from Title V and FEDOOP sources submitting an operating or renewal application.

[x] AP-100B: Emission Unit Definition *	[ ] AP-200A: Generic Process	[x] AP-300A: Generic Control Device
[x] AP-100C: Emission Data *	[ ] AP-200B: Abrasive Blasting	[ ] AP-300B: Baghouse (Fabric Filter)
[x] AP-100D: Stack Data *	[ ] AP-200C: Grain Terminal	[ ] AP-300C: Cyclone
[x] AP-100E: Emission Calculations *	[ ] AP-200D: Silo/Storage Bin	[ ] AP-300D: Settling Chamber
[ ] AP-100F: Emission Summary	[x] AP-200E: Combustion Source	[ ] AP-300E: Electrostatic Precipitator
[ ] AP-100G: Alternate Operating Scenario	[ ] AP-200F: Crematory	[ ] AP-300F: Chemical Scrubber
[x] AP-100H: Applicable Requirements *	[ ] AP-200G: Printing Press Operation	[x] AP-300G: Reducing System (SCR, etc.)
[x] AP-100J: Compliance Monitoring *	[ ] AP-200H: Surface Coating Operation	[ ] AP-300H: Condenser
[ ] AP-100K: Compliance Certification *	[x] AP-200J: Generator or Engine	[ ] AP-300J: Liquid/Vapor Separator
[ ] AP-100L: Compliance Schedule #	[ ] AP-200K: Used Oil Heater	[ ] AP-300K: Adsorption
[ ] AP-100M: Risk Management Plan	[ ] AP-200L: Hot Mix Asphalt	[ ] AP-300L: Oxidizer or Afterburner
[ ] AP-100N: Episode Standby Plan	[ ] AP-200M: Dry Cleaning	[ ] AP-300M: Flare
[x] AP-100P: Insignificant Activities *	[ ] AP-200N: VOC Storage Tank	[ ] AP-300N: Venturi Scrubber
[ ] AP-150B: Production Rate *	[ ] AP-200P: Solvent Metal Cleaning	
[ ] AP-101X: Request for Temporary Exemption	[ ] AP-200R: Cooling Tower	[ ] AP-900B: Certified Progress Report #

Supporting Documents

Check other attachments which are part of this application:

- [x] Process Flow Diagram (**Required** for **all** construction applications)
- [ ] Material Safety Data Sheets (MSDS)
- [ ] Calculations for Actual emissions (**Required for FEDOOP Renewals**)
- [ ] Stack Test Reports
- [ ] Claim of Confidentiality
- [x] Other: Site Map; Application Report; Acid Rain Permit Application

Filing Fee

The filing fee listed in the revision of APCD *Regulation 2.08 Schedule of Fees* in effect on the date of filing is due with the submittal of the application. Your application will not be acted upon until the fee is received.

This fee is not required when updating facility information such as contacts or Responsible Officials.
This fee is not required for renewal of existing Title V and FEDOOP operating permits.

Fees may be paid with any major credit card EXCEPT American Express.

Contact Monica Little (502-574-7246) to pay by credit card.

[x] The appropriate filing fee is included with this application [ ] No fee required (as described above)

Emission Information

Minor sources are not required to complete the Actual Emissions and Requested Limit columns of the following section. Minor sources may also leave the Potential Emissions column blank, but doing so may delay processing of this application. FEDOOP and Title V sources must complete this section of the application.

The emissions shown below are: __ **plant-wide** X **this project only**

Pollutant	Potential Emissions (tons/year)	Previous Year Actual Emissions (Required for FEDOOP renewals) (tons/year)	Requested Limit PSD/NSR, FEDOOP*, etc. (tons/year)
PM	104.03	N/A	
PM_{10}	102.94	N/A	
$PM_{2.5}$	101.98	N/A	
CO	161.42	N/A	
NO_x	199.90	N/A	
SO_2	25.28	N/A	
Lead	8.85E-03	N/A	
VOC	51.56	N/A	
Total HAP	25.98	N/A	
Single HAP	16.40	N/A	

* FEDOOP must have at least one requested limit.

Responsible Office Certification

The "Responsible Official" is the person in charge of a principal business function, or other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of that person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit. See District regulation 1.02, section 1.71 for a complete, detailed definition of Responsible Official.

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in this document and all associated attachments are true, accurate, and complete.

BY:

Steven Turner
Typed or Printed Name of Signatory

12/15/2022 | 8:20 AM EST
Date

DocuSigned by:
Steven B. Turner
8AD647306F3E4A0...
Authorized Signature

VP Power Production
Title of Signatory

Change Responsible Official (RO) Designation

☐ This is notification that our facility is requesting to add the Responsible Official named below.
☐ This is notification that our facility is requesting to remove the Responsible Official named below.

This request must be signed by a current Responsible Official.

Typed or printed name of added or deleted R.O. — Date

Authorized Signature of added R.O. — Title of added R.O.

Additional RO e-mail: Phone:

Change Responsible Official (RO) Designation

☐ This is notification that our facility is requesting to add the Responsible Official named below.
☐ This is notification that our facility is requesting to remove the Responsible Official named below.

This request must be signed by a current Responsible Official.

Typed or printed name of added or deleted R.O. — Date

Authorized Signature of added R.O. — Title of added R.O.

Additional RO e-mail: Phone:

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100B

Emission Unit Definition

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

General Information

Plant Name: Louisville Gas & Electric Company - Mill Creek Generating Station		Plant ID: 127	
Date of Submission: 12/15/2022			
Emission Unit Name: EGU Unit 5 Gas Turbine with HRSG		Emission Unit ID: U23	
SIC code:	SCC code: 20100201	☑ Continuous	☐ Batch

Operating Schedule

		Hours / day	Days / week	Weeks / year	Seasonal Variation (%)	
Normal	(Mon-Fri)	24	5	52	Jan - Mar:	25
	(Sat-Sun)	24	2	52	Apr - Jun:	25
Maximum	(Mon-Fri)	24	5	52	Jul - Sep:	25
	(Sat-Sun)	24	2	52	Oct - Dec:	25

Emission Unit Definition

Process Description:	Internal combustion of natural gas in a single-cycle combustion turbine followed by a heat recovery steam generator (HRSG) with duct burning to power a combined-cycle GT and ST system
Raw Materials:	Natural Gas
Products:	Electricity

Fuel Usage

	Emission Process # E49a		Emission Process #	
	Primary Fuel	Secondary Fuel	Primary Fuel	Secondary Fuel
Fuel Type:	Natural Gas	N/A		
Normal usage per year:	20,856 MMscf/yr	N/A		
Maximum usage per year:	34,385 MMscf/yr	N/A		

Emission Process Information							
Emission Process/ Point Number	Emission Process/Point Description	Manufacturer	Model #	Maximum Rated Capacity	Date Installed (mm/dd/yy)	Control Equipment ID#	Stack ID#
E49a	Natural Gas Firing in GT & DB	Specific details regarding turbine manufacturer and model information will not be known until the project is further in development.		4,157 MMBtu/hr	3/1/2024	C43, C44	S49
E49b	Cold Startup Events			4,157 MMBtu/hr	3/1/2024	--	S49
E49c	Warm Startup Events			4,157 MMBtu/hr	3/1/2024	--	S49
E49d	Hot Startup Events			4,157 MMBtu/hr	3/1/2024	--	S49
E49e	Shutdown Events			4,157 MMBtu/hr	3/1/2024	--	S49

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100B

Emission Unit Definition

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

General Information

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of Submission:	12/15/2022		
Emission Unit Name:	Auxiliary Steam Boiler	Emission Unit ID:	U24
SIC code:	SCC code: 10200602	☑ Continuous	☐ Batch

Operating Schedule

		Hours / day	Days / week	Weeks / year	Seasonal Variation (%)	
Normal	(Mon-Fri)	24	5	52	Jan - Mar:	25
	(Sat-Sun)	24	2	52	Apr - Jun:	25
Maximum	(Mon-Fri)	24	5	52	Jul - Sep:	25
	(Sat-Sun)	24	2	52	Oct - Dec:	25

Emission Unit Definition

Process Description:	Natural-gas fired indirect heat exchanger designed to periodically assist with warm and cold startups of the CCT (U23)
Raw Materials:	Natural Gas
Products:	Steam

Fuel Usage

	Emission Process # E50		Emission Process #	
	Primary Fuel	Secondary Fuel	Primary Fuel	Secondary Fuel
Fuel Type:	Natural Gas	N/A		
Normal usage per year:	206.6 MMscf/yr	N/A		
Maximum usage per year:	826.4 MMscf/yr	N/A		

Emission Process Information							
Emission Process/ Point Number	Emission Process/Point Description	Manufacturer	Model #	Maximum Rated Capacity	Date Installed (mm/dd/yy)	Control Equipment ID#	Stack ID#
E50	Natural Gas Combustion w/ LNB & FGR	Specific details regarding auxiliary boiler manufacturer and model information will not be known until the project is further in development.		99.9 MMBtu/hr	3/1/2024	--	S50

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100B

Emission Unit Definition

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Louisville, KY 40203

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www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

General Information

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of Submission:	12/15/2022		
Emission Unit Name:	Fuel Gas (Dewpoint) Heater	Emission Unit ID:	U26
SIC code:	SCC code: 39990003	☑ Continuous	☐ Batch

Operating Schedule

		Hours / day	Days / week	Weeks / year	Seasonal Variation (%)	
Normal	(Mon-Fri)	24	5	52	Jan - Mar:	25
	(Sat-Sun)	24	2	52	Apr - Jun:	25
Maximum	(Mon-Fri)	24	5	52	Jul - Sep:	25
	(Sat-Sun)	24	2	52	Oct - Dec:	25

Emission Unit Definition

Process Description:	Natural gas-fired fuel gas (dewpoint) preheater to provide supplemental heating to NGCC system inlet natural gas feed stream when needed.
Raw Materials:	Natural Gas
Products:	Heat

Fuel Usage

	Emission Process # E52		Emission Process #	
	Primary Fuel	Secondary Fuel	Primary Fuel	Secondary Fuel
Fuel Type:	Natural Gas	N/A		
Normal usage per year:	124.1 MMscf/yr	N/A		
Maximum usage per year:	124.1 MMscf/yr	N/A		

Emission Process Information

Emission Process/ Point Number	Emission Process/Point Description	Manufacturer	Model #	Maximum Rated Capacity	Date Installed (mm/dd/yy)	Control Equipment ID#	Stack ID#
E52	NG Fuel Combustion (15 MMBtu/hr)	Specific details regarding dewpoint heater manufacturer and model information will not be known until the project is further in development.		15.0 MMBtu/hr	3/1/2024	--	S52

Louisville Metro Air Pollution Control District

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Emission Unit Definition

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Louisville, KY 40203

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General Information

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of Submission:	12/15/2022		
Emission Unit Name:	2 MW Diesel Emergency Generator	Emission Unit ID:	U25
SIC code:	SCC code: 20200102	☑ Continuous	☐ Batch

Operating Schedule

		Hours / day	Days / week	Weeks / year	Seasonal Variation (%)	
Normal	(Mon-Fri)	Emergency use only, maximum of 500 hr/yr operation			Jan - Mar:	25
	(Sat-Sun)				Apr - Jun:	25
Maximum	(Mon-Fri)				Jul - Sep:	25
	(Sat-Sun)				Oct - Dec:	25

Emission Unit Definition

Process Description:	A new diesel-fired emergency generator will be installed as part of the NGCC project to supply electrical power in the event of a power outage.
Raw Materials:	Diesel
Products:	Electricity

Fuel Usage

	Emission Process # E51		Emission Process #	
	Primary Fuel	Secondary Fuel	Primary Fuel	Secondary Fuel
Fuel Type:	Diesel	N/A		
Normal usage per year:	68.5 Mgal/yr	N/A		
Maximum usage per year:	68.5 Mgal/yr	N/A		

Emission Process Information							
Emission Process/ Point Number	Emission Process/Point Description	Manufacturer	Model #	Maximum Rated Capacity	Date Installed (mm/dd/yy)	Control Equipment ID#	Stack ID#
E51	Diesel Fuel Combustion	Specific details regarding emergency generator engine manufacturer and model information will not be known until the project is further in development.		2,682 bhp	3/1/2024	--	S51

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100B

Emission Unit Definition

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Louisville, KY 40203

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FAX: (502) 574-5137
www.louisvilleky.gov/apcd
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General Information

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of Submission:	12/15/2022		
Emission Unit Name:	400 HP Diesel Driven Fire Pump	Emission Unit ID:	IA4/IE28
SIC code:	SCC code: 20200102	☑ Continuous	☐ Batch

Operating Schedule

		Hours / day	Days / week	Weeks / year	Seasonal Variation (%)	
Normal	(Mon-Fri)	Emergency use only, maximum of 500 hr/yr operation			Jan - Mar:	25
	(Sat-Sun)				Apr - Jun:	25
Maximum	(Mon-Fri)				Jul - Sep:	25
	(Sat-Sun)				Oct - Dec:	25

Emission Unit Definition

Process Description:	Diesel-fired emergency fire pump engine designed to supply water in the event of a fire and/or power outage at the NGCC plant
Raw Materials:	Diesel
Products:	Shaft Work

Fuel Usage

	Emission Process # IE28		Emission Process #	
	Primary Fuel	Secondary Fuel	Primary Fuel	Secondary Fuel
Fuel Type:	Diesel	N/A		
Normal usage per year:	10.2 Mgal/yr	N/A		
Maximum usage per year:	10.2 Mgal/yr	N/A		

Emission Process Information							
Emission Process/ Point Number	Emission Process/Point Description	Manufacturer	Model #	Maximum Rated Capacity	Date Installed (mm/dd/yy)	Control Equipment ID#	Stack ID#
IE28	Diesel Fuel Combustion	Specific details regarding emergency fire pump manufacturer and model information will not be known until the project is further in development.		400 bhp	3/1/2024	--	S53

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100C

Emission Data

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name: Louisville Gas & Electric Company - Mill Creek Generating Station   Plant ID: 127

Date of Submission: 12/15/2022

Emission Information

Emission Process/Point: E49a   Emission Process Description: Natural Gas Firing in GT & DB

Regulated Pollutant	CAS#	Maximum Emission Rate	Method (see note)	Allowable Emission Rate	Applicable Regulation	Requested Emission Rate	Controlled? (Y / N)
PM	N/A	98.28 tpy	5 (see Section 5.3 in Apx B)				N
PM_{10}	N/A	98.28 tpy					N
$PM_{2.5}$	N/A	98.28 tpy					N
NO_X	N/A	147.67 tpy		15 ppm at 15% O_2 **or** 54 ng/J (0.43 lb/MWh) of useful output	40 CFR 60.4320 6.42, Section 4.3		Y

Emission Process/Point: E49a   Emission Process Description: Natural Gas Firing in GT & DB

Regulated Pollutant	CAS#	Maximum Emission Rate	Method (see note)	Allowable Emission Rate	Applicable Regulation	Requested Emission Rate	Controlled? (Y / N)
CO	630-08-0	89.84 tpy	5 (see Section 5.3 in Apx B)				Y
VOC	N/A	31.36 tpy					Y
SO_2	7446-09-5	24.54 tpy	2	0.060 lb/MMBtu SO2	40 CFR 60.4365		N
H_2SO_4	7664-93-9	8.64 tpy	2				N

Emission Process/Point: E49a   Emission Process Description: Natural Gas Firing in GT & DB

Regulated Pollutant	CAS#	Maximum Emission Rate	Method (see note)	Allowable Emission Rate	Applicable Regulation	Requested Emission Rate	Controlled? (Y / N)
CO_2e	N/A	2,149,207 tpy	3 (AP-42 Section 3.1 and 40 CFR 98 Subpart C)				N
Lead	7439-92-1	0.01 tpy	3 (AP-42 Section 1.4)				N
Acetaldehyde	75-07-0	3.09 tpy	3 (AP-42 Section 3.1)				Y
Formaldehyde	50-00-0	3.95 tpy	6 (NESHAP YYYY)	91 ppbvd at 15% O_2	40 CFR 63.6100		Y

Emission Process/Point:	E49a	Emission Process Description:	Natural Gas Firing in GT & DB				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
Hexane	110-54-3	15.47 tpy	3 (AP-42 Section 1.4)				Y
Toluene	108-88-3	1.14 tpy	3 (AP-42 Section 3.1)				Y
1,3-Butadiene	106-99-0	0.004 tpy	3 (AP-42 Section 3.1)				Y
Acrolein	107-02-8	0.06 tpy	3 (AP-42 Section 3.1)				Y

Emission Process/Point:	E49a	Emission Process Description:	Natural Gas Firing in GT & DB				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
Propylene Oxide	75-56-9	0.25 tpy	3 (AP-42 Section 3.1)				Y
Total HAP	N/A	25.00 tpy	3 (sum of individual HAP)				Y

Emission Process/Point:	E49b	Emission Process Description:	Cold Startup Events				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
NO_X	N/A	1.05 tpy	6 (vendor estimate) (see Section 5.5 in Apx B)				N
CO	630-08-0	1.90 tpy					N
VOC	N/A	0.34 tpy					N
PM	N/A	0.08 tpy					N

Emission Process/Point:	E49b	Emission Process Description:	Cold Startup Events				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
PM_{10}	N/A	0.08 tpy	6 (vendor estimate) (see Section 5.5 in Apx B)				N
$PM_{2.5}$	N/A	0.08 tpy					N

Emission Process/Point:	E49c	Emission Process Description:	Warm Startup Events				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
NO_X	N/A	5.85 tpy	6 (vendor estimate) (see Section 5.5 in Apx B)				N
CO	630-08-0	10.71 tpy					N
VOC	N/A	2.72 tpy					N
PM	N/A	0.61 tpy					N

Emission Process/Point:	E49c	Emission Process Description:	Warm Startup Events				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
PM_{10}	N/A	0.61 tpy	6 (vendor estimate) (see Section 5.5 in Apx B)				N
$PM_{2.5}$	N/A	0.61 tpy					N

Emission Process/Point:	E49d	Emission Process Description:	Hot Startup Events				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
NO_X	N/A	6.75 tpy	6 (vendor estimate) (see Section 5.5 in Apx B)				N
CO	630-08-0	15.15 tpy					N
VOC	N/A	4.55 tpy					N
PM	N/A	0.75 tpy					N

Emission Process/Point:	E49d	Emission Process Description:	Hot Startup Events				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
PM_{10}	N/A	0.75 tpy	6 (vendor estimate) (see Section 5.5 in Apx B)				N
$PM_{2.5}$	N/A	0.75 tpy					N

Emission Process/Point:	E49e	Emission Process Description:	Shutdown Events				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
NO_X	N/A	5.85 tpy	6 (vendor estimate) (see Section 5.5 in Apx B)				N
CO	630-08-0	18.30 tpy					N
VOC	N/A	8.85 tpy					N
PM	N/A	0.38 tpy					N

Emission Process/Point:	E49e	Emission Process Description:	Shutdown Events				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
PM_{10}	N/A	0.38 tpy	6 (vendor estimate) (see Section 5.5 in Apx B)				N
$PM_{2.5}$	N/A	0.38 tpy					N

Emission Process/Point:	E50	Emission Process Description:	Natural Gas Combustion w/ LNB & FGR				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
PM	N/A	1.43 tpy	3 (AP-42 Section 1.4)	0.1 lb/MMBtu	7.06, Section 4.1.2		N
PM_{10}	N/A	1.43 tpy	3 (AP-42 Section 1.4) 6 (EPA Speciate Database)				N
$PM_{2.5}$	N/A	1.43 tpy	3 (AP-42 Section 1.4) 6 (EPA Speciate Database)				N
NO_X	N/A	15.93 tpy	6 (vendor guarantee)	0.04 lb/MMBtu with LNB or LNB/FGR, per suggested RACT	6.42, Section 4.3		N

Emission Process/Point:	E50	Emission Process Description:	Natural Gas Combustion w/ LNB & FGR				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
CO	630-08-0	16.16 tpy	6 (vendor guarantee)				N
VOC	N/A	2.27 tpy	3 (AP-42, Section 1.4)				N
SO_2	7446-09-5	0.59 tpy	2	0.8 lb/MMBtu	7.06, Section 5.1.2		N
H_2SO_4	7664-93-9	0.045 tpy	2				N

Emission Process/Point:	E50	Emission Process Description:	Natural Gas Combustion w/ LNB & FGR				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
CO_2e	N/A	51,238 tpy	3 (40 CFR 98 Subpart C)				N
Lead	7439-92-1	0.0002 tpy	3 (AP-42, Section 1.4)				N
Formaldehyde	50-00-0	0.03 tpy	3 (AP-42, Section 1.4)				N
Total HAP	N/A	0.78 tpy	3 (sum of individual HAP)				N

Emission Process/Point:	E51	Emission Process Description:	Diesel Fuel Combustion				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
PM	N/A	0.06 tpy	6 (NSPS IIII requirement)	0.20 g/kWh	40 CFR 60.4205(b)		N
PM_{10}	N/A	0.06 tpy	6 (NSPS IIII requirement)				N
$PM_{2.5}$	N/A	0.06 tpy	6 (NSPS IIII requirement)				N
NO_X	N/A	9.70 tpy	6 (vendor guarantee)	6.4 g/kWh (NO_X + NMHC)	40 CFR 60.4205(b)		N

Emission Process/Point:	E51	Emission Process Description:	Diesel Fuel Combustion				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
CO	630-08-0	0.80 tpy	6 (NSPS IIII requirement)	3.5 g/kWh	40 CFR 60.4205(b)		N
VOC	N/A	0.21 tpy	6 (vendor guarantee)	6.4 g/kWh (NOX + NMHC)	40 CFR 60.4205(b)		N
SO_2	7446-09-5	0.01 tpy	3 (AP-42 Section 3.4)				N
CO_2e	N/A	767.93 tpy	3 (40 CFR 98 Subpart C)				N

Emission Process/Point:	E51	Emission Process Description:	Diesel Fuel Combustion				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
Formaldehyde	N/A	0.0004 tpy	3 (AP-42 Section 3.4)				N
Total HAP	N/A	0.01 tpy	3 (sum of individual HAP)				N

Emission Process/Point:	E52	Emission Process Description:	NG Fuel Combustion (15 MMBtu/hr)				
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
PM	N/A	0.12 tpy	3 (AP-42 Section 1.4)	0.1 lb/MMBtu	7.06, Section 4.1.2		N
PM_{10}	N/A	0.12 tpy	3 (AP-42 Section 1.4) 6 (EPA Speciate Database)				N
$PM_{2.5}$	N/A	0.12 tpy	3 (AP-42 Section 1.4) 6 (EPA Speciate Database)				N
NO_X	N/A	2.39 tpy	6 (vendor guarantee)	0.04 lb/MMBtu, per suggested RACT	6.42, Section 4.3		N

Emission Process/Point:	E52	Emission Process Description:		NG Fuel Combustion (15 MMBtu/hr)			
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
CO	630-08-0	4.90 tpy	6 (vendor guarantee)				N
VOC	N/A	0.34 tpy	3 (AP-42, Section 1.4)				N
SO_2	7446-09-5	0.09 tpy	2	0.8 lb/MMBtu	7.06, Section 5.1.2		N
H_2SO_4	7664-93-9	0.0068 tpy	2				N

Emission Process/Point:	E52	Emission Process Description:		NG Fuel Combustion (15 MMBtu/hr)			
Regulated Pollutant	**CAS#**	**Maximum Emission Rate**	**Method (see note)**	**Allowable Emission Rate**	**Applicable Regulation**	**Requested Emission Rate**	**Controlled? (Y / N)**
CO_2e	N/A	7,693 tpy	3 (40 CFR 98 Subpart C)				N
Lead	7439-92-1	0.00003 tpy	3 (AP-42, Section 1.4)				N
Formaldehyde	50-00-0	0.005 tpy	3 (AP-42, Section 1.4)				N
Total HAP	N/A	0.12 tpy	3 (sum of individual				N

Note: Determination Method: (1) – Stack Test; (2) – Material Balance; (3) – Standard emission factor (AP-42, or specify); (4) – Engineering estimate; (5) - Special emission factor (specify); (6) – Other (specify)

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100D

Exhaust Stack Information

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Associated process equipment:	EGU Unit 5 Gas Turbine with HRSG	Emission Process/Point:	U23
Date of submission:	12/15/2022		

Exhaust Process/Point Information

Stack ID:	S49		
Description of exhaust point (stack, vent, roof monitor, indoors, etc.):	Stack		
Distance to nearest plant boundary from exhaust point discharge:	1,574 ft		
Discharge height above grade:	185 ft	Good Engineering Practice (GEP) height:	323 ft
Diameter (or equivalent diameter) of exhaust point:	24 ft		
Exit gas flow rate:	Maximum (ACFM) - 1,600,000	Minimum (ACFM) -	
Exit gas temperature:	@ maximum airflow - 171 ºF	@ maximum airflow -	
Orientation of exhaust:	Vertical Unobstructed	Is there a stack cap? ☐ Yes ☑ No	
Stack location:	Latitude - 38.0508	Longitude - -85.907408	

Stack Site Information

Dimensions of building on which exhaust point is located:	Length -	Width -	Height -
Location of stack relative to building:	Distance from North edge -	Distance from East edge -	
Distance to nearest building :		Direction to Nearest building:	
Dimensions of the nearest building:	Length -	Width -	Height -

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100D

Exhaust Stack Information

Deliver application to:
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Louisville, KY 40203

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FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Associated process equipment:	Auxiliary Steam Boiler	Emission Process/Point:	U24
Date of submission:	12/15/2022		

Exhaust Process/Point Information

Stack ID:	S50		
Description of exhaust point (stack, vent, roof monitor, indoors, etc.):	Stack		
Distance to nearest plant boundary from exhaust point discharge:	1,389 ft		
Discharge height above grade:	60 ft	Good Engineering Practice (GEP) height:	309 ft
Diameter (or equivalent diameter) of exhaust point:	3 ft		
Exit gas flow rate:	Maximum (ACFM) - 30,000	Minimum (ACFM) -	
Exit gas temperature:	@ maximum airflow - 295 ºF	@ maximum airflow -	
Orientation of exhaust:	Vertical unobstructed	Is there a stack cap?	☐ Yes ☑ No
Stack location:	Latitude - 38.050286	Longitude -	-85.906463

Stack Site Information

Dimensions of building on which exhaust point is located:	Length -	Width -	Height -
Location of stack relative to building:	Distance from North edge -	Distance from East edge -	
Distance to nearest building :	Direction to Nearest building:		
Dimensions of the nearest building:	Length -	Width -	Height -

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100D

Exhaust Stack Information

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Associated process equipment:	Fuel Gas (Dewpoint) Heater	Emission Process/Point:	U26
Date of submission:	12/15/2022		

Exhaust Process/Point Information

Stack ID:	S52				
Description of exhaust point (stack, vent, roof monitor, indoors, etc.):	Stack				
Distance to nearest plant boundary from exhaust point discharge:	1,383 ft				
Discharge height above grade:	18 ft		Good Engineering Practice (GEP) height:	320 ft	
Diameter (or equivalent diameter) of exhaust point:					
Exit gas flow rate:	Maximum (ACFM) -	1,250	Minimum (ACFM) -		
Exit gas temperature:	@ maximum airflow -	750 ºF	@ maximum airflow -		
Orientation of exhaust:	Vertical unobstructed		Is there a stack cap?	☐ Yes	☑ No
Stack location:	Latitude -	38.049703	Longitude -	-85.906274	

Stack Site Information

Dimensions of building on which exhaust point is located:	Length -	Width -	Height -
Location of stack relative to building:	Distance from North edge -	Distance from East edge -	
Distance to nearest building :	Direction to Nearest building:		
Dimensions of the nearest building:	Length -	Width -	Height -

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Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Associated process equipment:	2 MW Diesel Emergency Generator	Emission Process/Point:	U25
Date of submission:	12/15/2022		

Exhaust Process/Point Information			
Stack ID:	S51		
Description of exhaust point (stack, vent, roof monitor, indoors, etc.):	Stack		
Distance to nearest plant boundary from exhaust point discharge:	1,532 ft		
Discharge height above grade:	16 ft	Good Engineering Practice (GEP) height:	323 ft
Diameter (or equivalent diameter) of exhaust point:	18 in.		
Exit gas flow rate:	Maximum (ACFM) - 16,200	Minimum (ACFM) -	
Exit gas temperature:	@ maximum airflow - 900 ºF	@ maximum airflow -	
Orientation of exhaust:	Vertical	Is there a stack cap? ☐ Yes ☐ No	
Stack location:	Latitude - 38.050414	Longitude -	-85.906984

Stack Site Information			
Dimensions of building on which exhaust point is located:	Length -	Width -	Height -
Location of stack relative to building:	Distance from North edge -	Distance from East edge -	
Distance to nearest building :	Direction to Nearest building:		
Dimensions of the nearest building:	Length -	Width -	Height -

Louisville Metro Air Pollution Control District

Permit Application and Renewal
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Exhaust Stack Information

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Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Associated process equipment:	400 HP Diesel Driven Fire Pump	Emission Process/Point:	IA4/IE28
Date of submission:	12/15/2022		

Exhaust Process/Point Information

Stack ID:	S53		
Description of exhaust point (stack, vent, roof monitor, indoors, etc.):	Stack		
Distance to nearest plant boundary from exhaust point discharge:	1,176 ft		
Discharge height above grade:	13 ft	Good Engineering Practice (GEP) height:	213 ft
Diameter (or equivalent diameter) of exhaust point:	8 in.		
Exit gas flow rate:	Maximum (ACFM) - 1,875	Minimum (ACFM) -	
Exit gas temperature:	@ maximum airflow - 960 ºF	@ maximum airflow -	
Orientation of exhaust:	Horizontal	Is there a stack cap?	☐ Yes ☐ No
Stack location:	Latitude - 38.050368	Longitude -	-85.905731

Stack Site Information

Dimensions of building on which exhaust point is located:	Length -	Width -	Height -
Location of stack relative to building:	Distance from North edge -	Distance from East edge -	
Distance to nearest building :		Direction to Nearest building:	
Dimensions of the nearest building:	Length -	Width -	Height -

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100E

Emission Calculations

Deliver application to:
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Louisville, KY 40203

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FAX: (502) 574-5137
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Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of submission:	12/15/2022		

Emission Calculations

See Appendix B of the Application Package

	Louisville Metro Air Pollution Control District **Permit Application and Renewal** **Form AP-100H** **Applicable Requirements**	**Deliver application to:** 701 W. Ormsby Ave.Suite 303 Louisville, KY 40203 (502) 574-6000 FAX: (502) 574-5137 www.louisvilleky.gov/apcd airpermits@louisvilleky.gov

Plant Name: Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID: 127
Date of submission: 12/15/2022	

Applicable Regulations

Emission Process/Point Name:	EGU Unit 5 Gas Turbine with HRSG - Natural Gas Firing in GT & DB		Emission Process/Point:	E49a
Pollutant: All Regulated Pollutants				
	Special conditions:	**40 CFR 60.4333(a); 40 CFR 63.6105(c)**: Operate and maintain the emissions unit, air pollution control equipment, 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.		
	Emission regulation:		Emission standard:	
	Recordkeeping regulation:	40 CFR 60.5525	Recordkeeping requirement:	Maintain fuel purchase records for the permitted fuel(s).
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	EGU Unit 5 Gas Turbine with HRSG - Natural Gas Firing in GT & DB		Emission Process/Point:	E49a
Pollutant: NO_X				
	Special conditions:			
	Emission regulation:	40 CFR 60.4320(a); Regulation 6.42, Section 4.3	Emission standard:	For turbines operating at peak load: 15 ppm at 15% O_2 0.43 lb/MWh gross energy output For turbines operating at less than 75% of peak load: 96 ppm at 15% O2 4.7 lb/MWh gross energy output
		Regulation 6.42, Section 4.3	Emission standard:	The NO_X emission rate for the NGCC (U23) shall be determined using the methods and procedures specified in the NO_X RACT Plan, except that any reference to an annual average shall be read as a rolling 30-day average.

	Recordkeeping regulation:	40 CFR 60.4350(b)	Recordkeeping requirement:	For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of 40 CFR 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.
	Reporting regulation:	40 CFR 60.4375(a)	Reporting requirement:	Submit reports of excess emissions and monitor downtime, as defined in 40 CFR 60.4380(b), in accordance with 40 CFR 60.7. Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.
		40 CFR 60.4395	Reporting requirement:	Submit reports of excess emissions to the Administrator semiannually, except when more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance of the source. All reports shall be postmarked by the 60th day following the end of each six month period.
		40 CFR 75 Subpart G	Reporting requirement:	Comply with the reporting requirements for Continuous Emissions Monitoring as specified in 40 CFR 75 Subpart G.
		Regulation 6.42, Section 4.3	Reporting requirement:	Comply with the quarterly reporting requirements as specified in Appendix A to the NOX RACT Plan.
	Monitoring regulation:	40 CFR 60.4340(b)(1)	Monitoring requirement:	Install, calibrate, maintain and operate a continuous emissions monitoring system as described in 40 CFR 60.4335(b) and 40 CFR 60.4345.
		40 CFR 60.4350	Monitoring requirement:	Identify excess emissions using the guidelines for CEMS equipment specified in 40 CFR 60.4350(a)-(f) and (h).

	Testing regulation:	40 CFR 60.4405	Testing requirement:	Perform the initial performance test required under 40 CFR 60.8 in the alternative manner specified by 40 CFR 60.4405(a) through (d).
		40 CFR 60.4400(b)	Testing requirement:	Perform the initial performance test required under 40 CFR 60.8 as specified by 40 CFR 60.4400(b)(2) and (4) through (6).

Emission Process/Point Name:	EGU Unit 5 Gas Turbine with HRSG - Natural Gas Firing in GT & DB	Emission Process/Point:	E49a

Pollutant: SO_2

	Special conditions:			
	Emission regulation:	40 CFR 60.4330(a)(2)	Emission standard:	The owner or operator shall not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.
	Recordkeeping regulation:		Recordkeeping requirement:	
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:	40 CFR 60.4365(a)	Monitoring requirement:	The owner or operator must demonstrate that the fuel used will not exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input and will have a total sulfur content of 20 grains of sulfur or less per 100 standard cubic feet by using fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel.
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	EGU Unit 5 Gas Turbine with HRSG - Natural Gas Firing in GT & DB	Emission Process/Point:	E49a

Pollutant: CO_2

	Special conditions:			
	Emission regulation:	40 CFR 60.5520(a)	Emission standard:	1,000 lb/MWh of gross energy output **or** 1,030 lb/MWh of net energy output on a 12-month rolling average basis

	Recordkeeping regulation:	40 CFR 60.5520(d)(1)	Recordkeeping requirement:	Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (i.e., uniform fuels) that result in a consistent emission rate of 160 lb CO_2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.
	Reporting regulation:	40 CFR 60.5550	Reporting requirement:	Prepare and submit the notifications specified in 40 CFR 60.7(a)(1) and (3) and 60.19, as applicable.
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	EGU Unit 5 Gas Turbine with HRSG - Natural Gas Firing in GT & DB	Emission Process/Point:	E49a

Pollutant: VOC

	Special conditions:	**Regulation 6.42, Section 4.1/4.2:** Implement good combustion and operating practices and comply with the applicable operating limitations of 40 CFR 63, Subpart YYYY.		
	Emission regulation:		Emission standard:	
	Recordkeeping regulation:	Regulation 6.42, Section 4.1/4.2	Recordkeeping requirement:	Comply with applicable recordkeeping requirements of 40 CFR 63, Subpart YYYY.
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:	Regulation 6.42, Section 4.1/4.2	Monitoring requirement:	Comply with applicable monitoring requirements of 40 CFR 63, Subpart YYYY.
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	EGU Unit 5 Gas Turbine with HRSG - Natural Gas Firing in GT & DB		Emission Process/Point:	E49a
Pollutant: TAC				
Special conditions:	**Regulation 5.20:** When a new TAC is introduced or for any existing TAC which does not have an established BAC or *de minimis* value, the owner or operator shall calculate and report these values as part of any aforementioned EA Demonstration. The form may be used for determining BAC and *de minimis* values. **Regulation 5.21:** The owner or operator shall perform a new Environmental Acceptability (EA) Demonstration or de minimis determination when the following events occur and submit the EA Demonstration on the schedule noted in the reporting section: (1) An application to construct or modify a process or process equipment is submitted to the District pursuant to Regulation 2.03, 2.04 or 2.05; (2) A modification of any physical modeling parameters such as fence lines or building heights that are not otherwise subject to the requirements in this permit that affects the demonstration of compliance; or (3) A change occurs in the process or process equipment, including raw material or fuel type substitution.			
Emission regulation:	Regulations 5.00 and 5.21	Emission standard:	The owner or operator shall not allow emissions of any TAC to exceed environmentally acceptable (EA) levels, whether specifically established by modeling or determined by the District to be *de minimis* .	
Recordkeeping regulation:	STAR Regulations	Recordkeeping requirement:	The owner or operator shall maintain records sufficient to demonstrate environmental acceptability, including, but not limited to, (M)SDS, analysis of emissions, and/or modeling results.	
Reporting regulation:		Reporting requirement:		
Monitoring regulation:		Monitoring requirement:		
Testing regulation:		Testing requirement:		

Emission Process/Point Name:	EGU Unit 5 Gas Turbine with HRSG - Natural Gas Firing in GT & DB		Emission Process/Point:	E49a
Pollutant: HAP				
	Special conditions:			
	Emission regulation:	40 CFR 63.6100	Emission standard:	Limit the concentration of formaldehyde to 91 ppbvd or less at 15% O_2, except during turbine startup. The period of time for turbine startup is subject to the limits specified in the definition of startup in 40 CFR 63.6175.
	Recordkeeping regulation:	40 CFR 63.6125(e)	Recordkeeping requirement:	Since the temperature monitoring system is a continuous monitoring system (CMS), the permittee must develop and implement a CMS quality control program that included written procedures for CMS according to 40 CFR 63.8(d)(1) through (2). The permittee must keep these written procedures on record for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, the owner or operator shall keep previous (i.e., superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. The program of corrective action should be included in the plan required under 40 CFR 63.8(d)(2).
		40 CFR 63.6155(a)	Recordkeeping requirement:	Keep the records as described in 40 CFR 63.6155(a)(1) through (7).

	Recordkeeping regulation:	40 CFR 63.6155(c)	Recordkeeping requirement:	Keep the records required in Table 5 of 40 CFR 63 Subpart YYYY to show continuous compliance with each operating limitation that applies.
		40 CFR 63.6155(d)	Recordkeeping requirement:	Any records required to be maintained by this part that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.
	Reporting regulation:	40 CFR 63.6140(b)	Reporting requirement:	Report each instance in which each emission limitation or operating limitation was not met. Report each instance in which the requirements in Table 7 40 CFR 63 Subpart YYYY that apply were not met. These instances are deviations from the emission and operating limitations 40 CFR 63 Subpart YYYY. These deviations must be reported according to the requirements in 40 CFR 63.6150.
		40 CFR 63.6145(a)	Reporting requirement:	Submit all of the notifications in 40 CFR 63.7(b) and (c), 63.8(f)(4), and 63.9(b) and (h) that apply by the dates specified.
		40 CFR 63.6145(e)	Reporting requirement:	Submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in 40 CFR 63.7(b)(1).
		40 CFR 63.6145(f)	Reporting requirement:	Submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

	Reporting regulation:	40 CFR 63.6150(a)	Reporting requirement:	Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of 40 CFR 63 Subpart YYYY. The semiannual compliance report must contain the information described in 40 CFR 63.6150 (a)(1) through (5). The semiannual compliance report, including the excess emissions and monitoring system performance reports of 40 CFR 63.10(e)(3), must be submitted by the dates specified in paragraphs (b)(1) through (5) of this section, unless the Administrator has approved a different schedule. After September 8, 2020, or once the reporting template has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 180 days, whichever date is later, you must submit all subsequent reports to the EPA following the procedure specified in 40 CFR 63.6150(g).
		40 CFR 63.6150(b)	Reporting requirement:	The first semiannual report and each subsequent semiannual report shall cover the periods specified in 40 CFR 63.6150(b)(1) and (3), respectively. The first semiannual report and each subsequent semiannual report shall be postmarked or delivered no later than the dates specified in 40 CFR 63.6150(b)(2) and (4), respectively.
		40 CFR 63.6150(b)(5)	Reporting requirement:	For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in 40 CFR 63.6150(b)(1) through (4).
		40 CFR 63.6150(f)	Reporting requirement:	Within 60 days after the date of completing each performance test required by 40 CFR 63 Subpart YYYY, submit the results of the performance test (as specified in 40 CFR 63.6145(f)) following the procedures specified in 40 CFR 63.6150(f)(1) through (3).

	Monitoring regulation:	40 CFR 63.6125(a)	Monitoring requirement:	For each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst, maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The permittee is not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature.
		40 CFR 63.6135(a)	Monitoring requirement:	Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), the permittee must conduct all parametric monitoring at all times the stationary combustion turbine is operating.
	Monitoring regulation:	40 CFR 63.6135(b)	Monitoring requirement:	Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. The permittee must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.
	Testing regulation:	40 CFR 63.6110(a)	Testing requirement:	The permittee must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of NESHAP YYYY that apply within 180 calendar days after the compliance date that is specified for the stationary combustion turbine in 40 CFR 63.6095 and according to the provisions in 40 CFR 63.7(a)(2).
		40 CFR 63.6110(b)	Testing requirement:	An owner or operator is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in 40 CFR 63.6110(b)(1) through (b)(5).

	Testing regulation:	40 CFR 63.6115	Testing requirement:	Subsequent performance tests must be performed on an annual basis as specified in Table 3 of 40 CFR 63 Subpart YYYY.
		40 CFR 63.6120(a) and (b)	Testing requirement:	Conduct each performance test in Table 3 of 40 CFR 63 Subpart YYYY that applies.
		40 CFR 63.6120(c)	Testing requirement:	Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent. After September 8, 2020, performance tests shall be conducted under such conditions based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. The owner or operator may not conduct performance tests during periods of malfunction. The owner or operator must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent normal operation. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.
		40 CFR 63.6120(d)	Testing requirement:	Conduct three separate test runs for each performance test, and each test run must last at least 1 hour.

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Plant Name: Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID: 127
Date of submission: 12/15/2022	

Applicable Regulations

Emission Process/Point Name: NG Fired Auxiliary Boiler (99.9 MMBtu/hr); Fuel Gas (Dewpoint) Heater (15 MMBtu/hr) — Emission Process/Point: E50, E52

Pollutant: All Regulated Pollutants

Special conditions:			
Emission regulation:		Emission standard:	
Recordkeeping regulation:	40 CFR 48c(g)(2)	Recordkeeping requirement:	The owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in 40 CFR 60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.
	40 CFR 60.48c(i)	Recordkeeping requirement:	All records required under 40 CFR 60.48c shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.
Reporting regulation:	40 CFR 60.48c(a)	Reporting requirement:	The owner or operator shall submit notification of the date of construction or reconstruction and actual startup, as provided by 40 CFR 60.7. The notification shall include the design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.
Monitoring regulation:	40 CFR 60.48c(g)(2)	Monitoring requirement:	Monitor fuel usage (MMscf) on a monthly basis.

	Testing regulation:	Regulation 1.04, Section 2.8	Testing requirement:	Permit the District or Administrator of the EPA to conduct performance tests at any reasonable time, cause the affected facility to be operated for purposes of those tests under the conditions as the District or the Administrator of the EPA may specify based on representative performance of the affected facility, and make available to the District those records as may be necessary to determine the performance.

Emission Process/Point Name:	NG Fired Auxiliary Boiler (99.9 MMBtu/hr); Fuel Gas (Dewpoint) Heater (15 MMBtu/hr)	Emission Process/Point:	E50, E52

Pollutant: HAP

	Special conditions:	**40 CFR 63.7500(a)(1):** Meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to 40 CFR 63 Subpart DDDDD, as applicable, for each boiler or process heater, except as provided under 40 CFR 63.7522. **40 CFR 63.7500(a)(3):** Operate and maintain any affected source (as defined in 40 CFR 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. **40 CFR 63.7505(a)**: The owner or operator shall be in compliance with the work practice standards in 40 CFR 63, Subpart DDDDD		
	Emission regulation:		Emission standard:	
	Recordkeeping regulation:	40 CFR 63.7555(a)	Recordkeeping requirement:	You must keep records according to 40 CFR 63.7555(a)(1) and (2): (1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). (2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in 40 CFR 63.10(b)(2)(viii).

	Recordkeeping regulation:	40 CFR 63.7555(h)	Recordkeeping requirement:	If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.
		40 CFR 63.7560	Recordkeeping requirement:	Records shall be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). Each record shall be kept for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Each record shall be kept on site, or they shall be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). Records can be kept off site for the remaining 3 years.
	Reporting Regulation:	40 CFR 63.7495(d)	Reporting requirement:	Meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD.
		40 CFR 63.7530(f)	Reporting requirement:	Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 7545(e).
		40 CFR 63.7540(b)	Reporting requirement:	Report each instance in which an emission limit and operating limit in 40 CFR 63, Subpart DDDDD, Table 3, as applicable, was not met. These instances are deviations from the emission limits or operating limits, respectively, in 40 CFR 63, Subpart DDDDD. These deviations shall be reported according to the requirements in 40 CFR 63.7550.

	Reporting Regulation:	40 CFR 63.7545(a)	Reporting requirement:	Submit to the Administrator all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified.
		40 CFR 63.7545(c)	Reporting requirement:	As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.
		40 CFR 63.7545(e)	Reporting requirement:	The permittee shall submit the Notification of Compliance Status and shall contain the information specified in 40 CFR 63.7545(e)(1) and (8) and shall be submitted within 60 days of the compliance date specified at 40 CFR 63.7495(b).
		40 CFR 63.7545(f)	Reporting requirement:	If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5).
		40 CFR 63.7550(a)	Reporting requirement:	Submit each report in 40 CFR 63, Subpart DDDDD, Table 9 that applies.
		40 CFR 63.7550(b)	Reporting requirement:	Submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in 40 CFR 63.7550(b)(1) through (4).
		40 CFR 63.7550(b)(5)	Reporting requirement:	For each affected source that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4).

	Reporting Regulation:	40 CFR 63.7550(c)(1)	Reporting requirement:	Submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii).
		40 CFR 63.7550(h)(1)	Reporting requirement:	The permittee must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (http://www.epa.gov/ttn/chief/cedri/index.html), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.
	Monitoring regulation:	40 CFR 63.7515(d)	Monitoring requirement:	Conduct an annual performance tune-up according to 40 CFR 63.7540(a)(10). Each annual tune-up specified in 40 CFR 63.7540(a)(10) shall be no more than 13 months after the previous tune-up, respectively. The first annual tune-up shall be no later than 13 months after the initial startup of the new affected source, respectively.
	Testing regulation:	40 CFR 63.7510(g)	Testing requirement:	Demonstrate initial compliance with applicable work practice standards in Table 3 annually as specified in 63.7515(d).
		40 CFR 63.7540(a)	Testing requirement:	Demonstrate continuous compliance with the work practice standards in Table 3 to 40 CFR 63, Subpart DDDDD that apply.
		40 CFR 63.7540(a)(10) or (12)	Testing requirement:	Conduct an annual (or every 5 years if using continuous oxygen trim system) tune-up of the process heater to demonstrate continuous compliance as specified in 63.7540(a)(10)(i) through (vi). Conduct the tune-up while burning the type of fuel that provided the majority of the heat input to the process heater over the 12 months prior to the tune-up.
		40 CFR 63.7540(a)(13)	Testing requirement:	If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup.

Emission Process/Point Name:	NG Fired Auxiliary Boiler (99.9 MMBtu/hr); Fuel Gas (Dewpoint) Heater (15 MMBtu/hr)	Emission Process/Point:	E50, E52
Pollutant: NO_X			
Special conditions:			
Emission regulation:	Regulation 6.42, Section 4.3	Emission standard:	See permit attached NO_X RACT Plan
Recordkeeping regulation:	Regulation 6.42, Section 4.3	Recordkeeping requirement:	The owner or operator shall record and maintain records of the amount of fuel combusted in each unit during each calendar month. The owner or operator shall calculate and maintain records of the lb/hr NOx emissions from each unit, determined by multiplying the actual total heat input (in MMBtu) and the manufacturer certified emissions factor, based upon a rolling 30-day average, in order to demonstrate compliance.
Reporting regulation:	Regulation 2.16, Section 4.1.9.3	Reporting requirement:	The owner or operator shall identify all periods of exceeding a NO_X emission standard during a semi-annual reporting period. The semi- annual compliance report shall include the following: (1) Emission Unit ID number and emission point ID number; (2) Identification of all periods during which a deviation occurred; (3) A description, including the magnitude, of the deviation; (4) If known, the cause of the deviation; (5) A description of all corrective actions taken to abate the deviation; and (6) If no deviations occur during a semi-annual reporting period, the report shall contain a negative declaration.
Monitoring regulation:		Monitoring requirement:	

	Testing regulation:	Regulation 6.42, Section 5.1	Testing requirement:	Owners or operators subject to Section 4 shall conduct performance tests or conduct continuous emission monitoring to verify compliance. For sources that opt for performance testing, a performance test shall be required annually for the first 2 years. If the facility is found to be in compliance during both of these tests, then the performance tests shall be conducted every two years after the second test, unless the facility fails to demonstrate compliance with its VOC or NO emission standard. In this case, the facility shall return to the annual performance test schedule for that pollutant until the District determines that compliance has been shown for a duration adequate to demonstrate that emissions are not likely to exceed the standards in the future.

Emission Process/Point Name:	NG Fired Auxiliary Boiler (99.9 MMBtu/hr); Fuel Gas (Dewpoint) Heater (15 MMBtu/hr)		Emission Process/Point:	E50, E52
Pollutant: PM				
	Special conditions:			
	Emission regulation:	Regulation 7.06, Section 4.1.2	Emission standard:	The owner or operator shall not cause to be discharged into the atmosphere from each affected facility PM in excess of 0.10 lb/MMBtu actual total heat input based upon a rolling 30-day average.
	Recordkeeping regulation:		Recordkeeping requirement:	
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	NG Fired Auxiliary Boiler (99.9 MMBtu/hr); Fuel Gas (Dewpoint) Heater (15 MMBtu/hr)		Emission Process/Point:	E50, E52
Pollutant: SO_2				
	Special conditions:			
	Emission regulation:	Regulation 7.06, Section 5.1.2	Emission standard:	The owner or operator shall not cause to be discharged into the atmosphere from each affected facility any gases which contain SO2 in excess of 0.8 lb/MMBtu actual total heat input based upon a rolling 30- day average.
	Recordkeeping regulation:		Recordkeeping requirement:	
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	NG Fired Auxiliary Boiler (99.9 MMBtu/hr); Fuel Gas (Dewpoint) Heater (15 MMBtu/hr)	Emission Process/Point:	E50, E52

Pollutant: VOC				
	Special conditions:	**Regulation 6.42, Section 4.1/4.3:** Implement good combustion and operating practices.		
	Emission regulation:		Emission standard:	
	Recordkeeping regulation:		Recordkeeping requirement:	
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	NG Fired Auxiliary Boiler (99.9 MMBtu/hr); Fuel Gas (Dewpoint) Heater (15 MMBtu/hr)	Emission Process/Point:	E50, E52

Pollutant: TAC				
	Special conditions:	**Regulation 5.20:** When a new TAC is introduced or for any existing TAC which does not have an established BAC or *de minimis* value, the owner or operator shall calculate and report these values as part of any aforementioned EA Demonstration. The form may be used for determining BAC and *de minimis* values. **Regulation 5.21:** The owner or operator shall perform a new Environmental Acceptability (EA) Demonstration or de minimis determination when the following events occur and submit the EA Demonstration on the schedule noted in the reporting section: (1) An application to construct or modify a process or process equipment is submitted to the District pursuant to Regulation 2.03, 2.04 or 2.05; (2) A modification of any physical modeling parameters such as fence lines or building heights that are not otherwise subject to the requirements in this permit that affects the demonstration of compliance; or (3) A change occurs in the process or process equipment, including raw material or fuel type substitution.		
	Emission regulation:	Regulations 5.00 and 5.21	Emission standard:	The owner or operator shall not allow emissions of any TAC to exceed environmentally acceptable (EA) levels, whether specifically established by modeling or determined by the District to be *de minimis* .
	Recordkeeping regulation:	STAR Regulations	Recordkeeping requirement:	The owner or operator shall maintain records sufficient to demonstrate environmental acceptability, including, but not limited to, (M)SDS, analysis of emissions, and/or modeling results.
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	NG Fired Auxiliary Boiler (99.9 MMBtu/hr); Fuel Gas (Dewpoint) Heater (15 MMBtu/hr)		Emission Process/Point:	E50, E52
Pollutant: Opacity				
	Special conditions:			
	Emission regulation:	Regulation 7.06, Section 4.2	Emission standard:	The owner or operator combusting natural gas shall not cause to be discharged into the atmosphere from any affected facility PM emissions which exhibit greater than 20% opacity. A maximum of 40% opacity shall be permissible for not more than two consecutive minutes in any 60 consecutive minutes. A maximum of 40% opacity shall be permissible for not more than six consecutive minutes in any 60 consecutive minutes during cleaning the fire box or blowing soot.
	Recordkeeping regulation:		Recordkeeping requirement:	
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100H

Applicable Requirements

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name: Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID: 127
Date of submission: 12/15/2022	

Applicable Regulations

Emission Process/Point Name: 2 MW Diesel Emergency Generator - Diesel Fuel Combustion   Emission Process/Point: E51

Pollutant: All Regulated Pollutants

Special conditions:	**40 CFR 60.4207(b):** Use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel. **40 CFR 60.4211(a):** Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions. Change only those emission-related settings that are permitted by the manufacturer. Meet the requirements of 40 CFR parts 89, 94, and/or 1068, as they apply. **40 CFR 60.4211(c)**: Comply by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b) for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4205(g). **40 CFR 60.4211(f):** Operate according to the requirements in 40 CFR 60.4211(f)(1) through (3) to be considered an emergency stationary ICE.		
Emission regulation:		Emission standard:	
Recordkeeping regulation:	40 CFR 60.4214(b)	Recordkeeping requirement:	Maintain records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.
Reporting regulation:		Reporting requirement:	
Monitoring regulation:	40 CFR 60.4209(a)	Monitoring requirement:	Install a non-resettable hour meter prior to startup of the engine.
Testing regulation:		Testing requirement:	

Emission Process/Point Name: 2 MW Diesel Emergency Generator - Diesel Fuel Combustion			Emission Process/Point:	E51
Pollutant: NO_X				
Special conditions:				
Emission regulation:	40 CFR 60.4202(a)(2), via 40 CFR 60.4205(b)	Emission standard:	NMHC + NOX shall not exceed 6.4 g/kWh according to Tier 2 standards for > 560 kW engines.	
Recordkeeping regulation:		Recordkeeping requirement:		
Reporting regulation:		Reporting requirement:		
Monitoring regulation:		Monitoring requirement:		
Testing regulation:		Testing requirement:		

Emission Process/Point Name: 2 MW Diesel Emergency Generator - Diesel Fuel Combustion			Emission Process/Point:	E51
Pollutant: VOC				
Special conditions:				
Emission regulation:	40 CFR 60.4202(a)(2), via 40 CFR 60.4205(b)	Emission standard:	NMHC + NOX shall not exceed 6.4 g/kWh according to Tier 2 standards for > 560 kW engines.	
Recordkeeping regulation:		Recordkeeping requirement:		
Reporting regulation:		Reporting requirement:		
Monitoring regulation:		Monitoring requirement:		
Testing regulation:		Testing requirement:		

Emission Process/Point Name: 2 MW Diesel Emergency Generator - Diesel Fuel Combustion			Emission Process/Point:	E51
Pollutant: CO				
Special conditions:				
Emission regulation:	40 CFR 60.4202(a)(2), via 40 CFR 60.4205(b)	Emission standard:	CO shall not exceed 3.5 g/kWh according to Tier 2 standards for > 560 kW engines.	
Recordkeeping regulation:		Recordkeeping requirement:		
Reporting regulation:		Reporting requirement:		
Monitoring regulation:		Monitoring requirement:		
Testing regulation:		Testing requirement:		

Emission Process/Point Name: 2 MW Diesel Emergency Generator - Diesel Fuel Combustion			Emission Process/Point:	E51
Pollutant: PM				
Special conditions:				
Emission regulation:	40 CFR 60.4202(a)(2), via 40 CFR 60.4205(b)	Emission standard:	PM shall not exceed 0.20 g/kWh according to Tier 2 standards for > 560 kW engines.	
Recordkeeping regulation:		Recordkeeping requirement:		
Reporting regulation:		Reporting requirement:		
Monitoring regulation:		Monitoring requirement:		
Testing regulation:		Testing requirement:		

Emission Process/Point Name: 2 MW Diesel Emergency Generator - Diesel Fuel Combustion			Emission Process/Point: E51	
Pollutant: HAP				
	Special conditions:	**40 CFR 63.6590(c)**: Meet the requirements of 40 CFR 63 Subpart ZZZZ by complying with 40 CFR 60 Subpart IIII.		
	Emission regulation:		Emission standard:	
	Recordkeeping regulation:		Recordkeeping requirement:	
	Reporting regulation:	40 CFR 63.6645(f)	Reporting requirement:	Submit an Initial Notification with the information in 40 CFR 63.9(b)(2)(i) through (v), and a statement that the stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions). By 63.6645(c), the initial notification should be submitted no later than 120 days after startup(since 63.6595(a)(3) states startup is when compliance begins).
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name: 2 MW Diesel Emergency Generator - Diesel Fuel Combustion			Emission Process/Point: E51	
Pollutant: TAC				
	Special conditions:	**Regulation 5.20:** When a new TAC is introduced or for any existing TAC which does not have an established BAC or *de minimis* value, the owner or operator shall calculate and report these values as part of any aforementioned EA Demonstration. The form may be used for determining BAC and *de minimis* values. **Regulation 5.21:** The owner or operator shall perform a new Environmental Acceptability (EA) Demonstration or de minimis determination when the following events occur and submit the EA Demonstration on the schedule noted in the reporting section: (1) An application to construct or modify a process or process equipment is submitted to the District pursuant to Regulation 2.03, 2.04 or 2.05; (2) A modification of any physical modeling parameters such as fence lines or building heights that are not otherwise subject to the requirements in this permit that affects the demonstration of compliance; or (3) A change occurs in the process or process equipment, including raw material or fuel type substitution.		
	Emission regulation:	Regulations 5.00 and 5.21	Emission standard:	The owner or operator shall not allow emissions of any TAC to exceed environmentally acceptable (EA) levels, whether specifically established by modeling or determined by the District to be *de minimis* .
	Recordkeeping regulation:	STAR Regulations	Recordkeeping requirement:	The owner or operator shall maintain records sufficient to demonstrate environmental acceptability, including, but not limited to, (M)SDS, analysis of emissions, and/or modeling results.

	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	2 MW Diesel Emergency Generator - Diesel Fuel Combustion	Emission Process/Point:	E51
Pollutant:	Smoke		

	Special conditions:			
	Emission regulation:	40 CFR 4202(a)(2), via 40 CFR 60.4205(b)	Emission standard:	Measure smoke as specified in 40 CFR 1039.501(c). Smoke from your engines may not exceed the following standards: (1) 20 percent during the acceleration mode. (2) 15 percent during the lugging mode. (3) 50 percent during the peaks in either the acceleration or lugging modes.
	Recordkeeping regulation:		Recordkeeping requirement:	
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	400 HP Diesel Driven Fire Pump	Emission Process/Point:	IA4
Pollutant:	All Regulated Pollutants		

	Special conditions:	**40 CFR 60.4207(b):** Use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel. **40 CFR 60.4211(a):** Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions. Change only those emission-related settings that are permitted by the manufacturer. Meet the requirements of 40 CFR parts 89, 94, and/or 1068, as they apply. **40 CFR 60.4211(c):** Comply by purchasing an engine certified to the emission standards in 40 CFR 60.4205(c) for the same model year and NFPA nameplate engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4205(g).		
	Emission regulation:		Emission standard:	
	Recordkeeping regulation:	40 CFR 60.4214(b)	Recordkeeping requirement:	Maintain records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:	40 CFR 60.4209(a)	Monitoring requirement:	Install a non-resettable hour meter prior to startup of the engine.
	Testing regulation:		Testing requirement:	

Emission Process/Point Name:	400 HP Diesel Driven Fire Pump	Emission Process/Point:	IA4
Pollutant:	NO_X		
Special conditions:			
Emission regulation:	40 CFR 60.4205(c)	Emission standard:	NMHC + NOX shall not exceed 4.0 g/kWh according to Table 4 to 40 CFR Subpart IIII for engine ratings between 300 and 600 hp.
Recordkeeping regulation:		Recordkeeping requirement:	
Reporting regulation:		Reporting requirement:	
Monitoring regulation:		Monitoring requirement:	
Testing regulation:		Testing requirement:	

Emission Process/Point Name:	400 HP Diesel Driven Fire Pump	Emission Process/Point:	IA4
Pollutant:	VOC		
Special conditions:			
Emission regulation:	40 CFR 60.4205(c)	Emission standard:	NMHC + NOX shall not exceed 4.0 g/kWh according to Table 4 to 40 CFR Subpart IIII for engine ratings between 300 and 600 hp.
Recordkeeping regulation:		Recordkeeping requirement:	
Reporting regulation:		Reporting requirement:	
Monitoring regulation:		Monitoring requirement:	
Testing regulation:		Testing requirement:	

Emission Process/Point Name:	400 HP Diesel Driven Fire Pump	Emission Process/Point:	IA4
Pollutant:	CO		
Special conditions:			
Emission regulation:	40 CFR 60.4205(c)	Emission standard:	CO shall not exceed 3.5 g/kWh according to Table 4 to 40 CFR Subpart IIII for engine ratings between 300 and 600 hp.
Recordkeeping regulation:		Recordkeeping requirement:	
Reporting regulation:		Reporting requirement:	
Monitoring regulation:		Monitoring requirement:	
Testing regulation:		Testing requirement:	

Emission Process/Point Name:	400 HP Diesel Driven Fire Pump	Emission Process/Point:	IA4
Pollutant:	PM		
Special conditions:			
Emission regulation:	40 CFR 60.4205(c)	Emission standard:	PM shall not exceed 0.20 g/kWh according to Table 4 to 40 CFR Subpart IIII for engine ratings between 300 and 600 hp.
Recordkeeping regulation:		Recordkeeping requirement:	
Reporting regulation:		Reporting requirement:	
Monitoring regulation:		Monitoring requirement:	
Testing regulation:		Testing requirement:	

Emission Process/Point Name: 400 HP Diesel Driven Fire Pump			Emission Process/Point: IA4	
Pollutant: HAP				
	Special conditions:	**40 CFR 63.6590(c)**: Meet the requirements of 40 CFR 63 Subpart ZZZZ by complying with 40 CFR 60 Subpart IIII.		
	Emission regulation:		Emission standard:	
	Recordkeeping regulation:		Recordkeeping requirement:	
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Emission Process/Point Name: 400 HP Diesel Driven Fire Pump			Emission Process/Point: IA4	
Pollutant: TAC				
	Special conditions:	**Regulation 5.20:** When a new TAC is introduced or for any existing TAC which does not have an established BAC or *de minimis* value, the owner or operator shall calculate and report these values as part of any aforementioned EA Demonstration. The form may be used for determining BAC and *de minimis* values. **Regulation 5.21:** The owner or operator shall perform a new Environmental Acceptability (EA) Demonstration or de minimis determination when the following events occur and submit the EA Demonstration on the schedule noted in the reporting section: (1) An application to construct or modify a process or process equipment is submitted to the District pursuant to Regulation 2.03, 2.04 or 2.05; (2) A modification of any physical modeling parameters such as fence lines or building heights that are not otherwise subject to the requirements in this permit that affects the demonstration of compliance; or (3) A change occurs in the process or process equipment, including raw material or fuel type substitution.		
	Emission regulation:	Regulations 5.00 and 5.21	Emission standard:	The owner or operator shall not allow emissions of any TAC to exceed environmentally acceptable (EA) levels, whether specifically established by modeling or determined by the District to be *de minimis* .
	Recordkeeping regulation:	STAR Regulations	Recordkeeping requirement:	The owner or operator shall maintain records sufficient to demonstrate environmental acceptability, including, but not limited to, (M)SDS, analysis of emissions, and/or modeling results.
	Reporting regulation:		Reporting requirement:	
	Monitoring regulation:		Monitoring requirement:	
	Testing regulation:		Testing requirement:	

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100J

Compliance Monitoring

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Emission Process/Point Name:	EGU Unit 5 Gas Turbine with HRSG	Emission Process/Point:	U23
Date of submission:	12/15/2022		

Monitoring Definition

List the operational parameters that are monitored and the frequency of monitoring

Parameter	Frequency	Method of measurement	Method of recording
Fuel Purchase Records	Continuous	Purchase records	Paper or digital files
NO_X Emissions	Continuous	CEMS	DAHS
Fuel Sulfur Content	Continuous	Current, valid purchase contract, tariff sheet, or transportation contract for natural gas fuel	Paper or digital files
VOC Emissions	Monthly	Manual calculations	Digital files
Catalyst Inlet Temperature	Continuous	CMS	DAHS

Describe any monitors in use, including manufacturer, model #, frequency of calibration, and location

Monitor Identification	Manufacturer	Model	Calibration Frequency	Location	Other Info

Specific details regarding CEMS information will not be known until the project is further in development.

Are any of these Continuous Emission monitors? ☑ Yes ☐ No

Pollutants monitored (check all that apply):
☐ Particulates (PM)
☐ Volatiles (VOC)
☑ Nitrogen oxides (NO_x)
☐ Other:
☐ Metals (specify:)
☐ HAP/TAC (specify:)
☐ Sulfur dioxide (SO_2)

Attach manufacturer's specification sheets, or complete the following:

Will multiple emission processes be monitored at the same location? ☐ Yes ☑ No
Which emission processes are monitored?

Will more than one emission process be emitting from the combined stack at any time? ☐ Yes ☑ No
Which emission processes emit simultaneously?

Monitoring and Alarm Information			
Describe the System Alarm(s):	Specific details regarding CEMS alarm information will not be known until the project is further in development.		
If there are more than three alarms, attach additional copies of this page as needed.			
Operating Parameter Monitored	**Describe Alarm Trigger**	**Monitoring Device or Alarm Type**	**Does the Alarm Initiate an Automated Response?**
		☐ Visual ☐ Auditory ☐ Automatic ☐ (Remote Monitoring) ☐ Other	☐ YES ☐ NO Describe:
		☐ Visual ☐ Auditory ☐ Automatic ☐ (Remote Monitoring) ☐ Other	☐ YES ☐ NO Describe:
		☐ Visual ☐ Auditory ☐ Automatic ☐ (Remote Monitoring) ☐ Other	☐ YES ☐ NO Describe:

Emission Tests	
List any emission measurement tests (stack tests) that have been performed in the past and attach a copy of the test reports:	
Test Purpose:	Test date:
Test Purpose:	Test date:
Test Purpose:	Test date:
Test Purpose:	Test date:

Louisville Metro Air Pollution Control District

Permit Application and Renewal
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Compliance Monitoring

Deliver application to:
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Louisville, KY 40203

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FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Emission Process/Point Name:	NG Fired Auxiliary Boiler (99.9 MMBtu/hr); Fuel Gas (Dewpoint) Heater	Emission Process/Point:	U24, U26
Date of submission:	12/15/2022		

Monitoring Definition

List the operational parameters that are monitored and the frequency of monitoring

Parameter	Frequency	Method of measurement	Method of recording
Fuel Usage	Monthly	Utility bills	Paper or digital files
NO_X Emissions	Monthly	Manual calculations	Digital files

Describe any monitors in use, including manufacturer, model #, frequency of calibration, and location

Monitor Identification	Manufacturer	Model	Calibration Frequency	Location	Other Info
No monitors will be installed to record the above operational parameters for this unit.					

Are any of these Continuous Emission monitors? ☐ Yes ☐ No

Pollutants monitored (check all that apply):
☐ Particulates (PM) ☐ Metals (specify:)
☐ Volatiles (VOC) ☐ HAP/TAC (specify:)
☐ Nitrogen oxides (NO_x) ☐ Sulfur dioxide (SO_2)
☐ Other:

Attach manufacturer's specification sheets, or complete the following:

Will multiple emission processes be monitored at the same location? ☐ Yes ☑ No
Which emission processes are monitored?

Will more than one emission process be emitting from the combined stack at any time? ☐ Yes ☑ No
Which emission processes emit simultaneously?

Monitoring and Alarm Information			
Describe the System Alarm(s): No monitors will be installed to record the above operational parameters.			
If there are more than three alarms, attach additional copies of this page as needed.			
Operating Parameter Monitored	**Describe Alarm Trigger**	**Monitoring Device or Alarm Type**	**Does the Alarm Initiate an Automated Response?**
		☐ Visual ☐ Auditory ☐ Automatic ☐ (Remote Monitoring) ☐ Other	☐ YES ☐ NO Describe:
		☐ Visual ☐ Auditory ☐ Automatic ☐ (Remote Monitoring) ☐ Other	☐ YES ☐ NO Describe:
		☐ Visual ☐ Auditory ☐ Automatic ☐ (Remote Monitoring) ☐ Other	☐ YES ☐ NO Describe:

Emission Tests	
List any emission measurement tests (stack tests) that have been performed in the past and attach a copy of the test reports:	
Test Purpose:	Test date:
Test Purpose:	Test date:
Test Purpose:	Test date:
Test Purpose:	Test date:

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100J

Compliance Monitoring

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Emission Process/Point Name:	2 MW Diesel Emergency Generator; 400 HP Diesel Driven Fire Pump	Emission Process/Point:	U25, IA4/IE28
Date of submission:	12/15/2022		

Monitoring Definition

List the operational parameters that are monitored and the frequency of monitoring

Parameter	Frequency	Method of measurement	Method of recording
Hours of Operation	While operating	Non-resettable hours meter	Non-resettable hours meter

Describe any monitors in use, including manufacturer, model #, frequency of calibration, and location

Monitor Identification	Manufacturer	Model	Calibration Frequency	Location	Other Info

Specific details regarding the non-resettable hours meter information will not be known until the project is further in development.

Are any of these Continuous Emission monitors? ☐ Yes ☐ No

Pollutants monitored (check all that apply):
☐ Particulates (PM) ☐ Metals (specify:)
☐ Volatiles (VOC) ☐ HAP/TAC (specify:)
☐ Nitrogen oxides (NO_x) ☐ Sulfur dioxide (SO_2)
☐ Other:

Attach manufacturer's specification sheets, or complete the following:

Will multiple emission processes be monitored at the same location? ☐ Yes ☑ No
Which emission processes are monitored?

Will more than one emission process be emitting from the combined stack at any time? ☐ Yes ☑ No
Which emission processes emit simultaneously?

Monitoring and Alarm Information			
Describe the System Alarm(s):	Specific details regarding non-resettable hours meter alarm information will not be known until the project is further in development.		
If there are more than three alarms, attach additional copies of this page as needed.			
Operating Parameter Monitored	**Describe Alarm Trigger**	**Monitoring Device or Alarm Type**	**Does the Alarm Initiate an Automated Response?**
		☐ Visual ☐ Auditory ☐ Automatic ☐ (Remote Monitoring) ☐ Other	☐ YES ☐ NO Describe:
		☐ Visual ☐ Auditory ☐ Automatic ☐ (Remote Monitoring) ☐ Other	☐ YES ☐ NO Describe:
		☐ Visual ☐ Auditory ☐ Automatic ☐ (Remote Monitoring) ☐ Other	☐ YES ☐ NO Describe:

Emission Tests	
List any emission measurement tests (stack tests) that have been performed in the past and attach a copy of the test reports:	
Test Purpose:	Test date:
Test Purpose:	Test date:
Test Purpose:	Test date:
Test Purpose:	Test date:

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-100P

Insignificant Activities

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

General Information

Plant Name: Louisville Gas & Electric Company - Mill Creek Generating Station   Plant ID: 127

Date of Submission: 12/15/2022

Emissions from Insignificant Activities must be reported on Emissions Inventory reports and must be included when calculating all plant-wide emission limits.

Reg 1.02 § #	Facility Type	Number of Units	PTE (each)
A.1.1	Indirect heat exchangers less than 10 MMBtu/hr, except those that burn waste oil. Size of unit(s): Fuel(s) burned:		
A.1.2	Indirect heat exchangers for residential building heat.		
A.2	Fixed internal combustion unless regulated elsewhere. (Emergency generator emissions are calculated based on operation for 500 hrs/yr)		
Any of the following facilities to which no standard is applicable or which emit an air pollutant to which no standard applies:			
A.3.1	Presses for extruding metals, minerals, or wood.		
A.3.2	Dry cleaners for which there is no emission, performance, or other standard.		
A.3.3	Lint traps used in conjunction with commercial laundry and dry cleaners.		
A.3.4	Brazing, soldering or welding equipment.		
A.3.5	Equipment commonly used in wood-working operations, except for conveying, hogging or burning of sawdust or wood waste.		
A.3.6	Foundry core-making equipment to which no heat is applied and for which there is no emission standard.		
A.3.7	Ovens used exclusively for curing potting materials or castings made with epoxy resins.		
A.3.8	Equipment used for compression or injection molding of plastics.		
A.3.9.1	Containers, reservoirs, or tanks used exclusively for dipping operations for coating objects with oils, waxes, or greases and where no organic solvents, diluents, or thinners are used.		
A.3.9.2	Containers, reservoirs, or tanks used exclusively for storage of lubricating oils or fuel oils with a vapor pressure of less than 10 mmHg at conditions of 20°C and 760 mmHg.		
A.3.10	Emergency relief vents, stacks and ventilating systems.		
A.3.11	Laboratory ventilating and exhausting systems which are not used for radioactive air contaminants.		

Reg 1.02 § #	Facility Type	Number of Units	PTE (each)
A.3.12	Process, exhaust or ventilating systems in bakeries or eating establishments preparing food for human consumption.		
A.3.13	Blast cleaning equipment using a suspension of abrasives in water.		
A.3.14	Equipment used exclusively for heat treating, soaking, case hardening or surface conditioning of metal objects ... when natural gas or LP gas is used as fuel.		
A.3.15	Equipment used for washing or drying products fabricated from metal or glass provided no volatile organic materials are used in the process and no oil or solid fuel is burned.		
A.3.16	Equipment, machines, devices, or contrivances built or installed to be used at a domestic residence for domestic use.		
A.3.17	Porcelain enameling furnaces, porcelain enameling drying ovens, vitreous enameling furnaces or vitreous enameling drying ovens.		
A.3.18	Crucible or pot furnaces with a brim full capacity of less than 450 cubic inches of any molten metal.		
A.3.19	Facilities using only peanut oil, sunflower oil, cottonseed oil or canola oil.		
A.3.20	Soil or ground water contamination remediation projects that are entirely passive or entail the total removal of the contaminated substrate for disposal in a certified landfill.		
A.3.21	Dust or particulate collectors that are located in-doors, vent directly indoors into the work space, collect no more than one ton of material per year.		
A.3.23	Portable diesel or gasoline storage tanks with a maximum capacity of less than 500 gallons.		
A.3.24	Storage vessels for VOCs with a maximum capacity of 250 gallons or less. List materials stored:		
A.3.25	Diesel or fuel oil storage tanks that are not used for distribution, sale or resale, and that have less than two times the capacity of the vessel in annual turnover of the fluid contained.		
A.2.3.26	All pressurized VOC storage vessels. List materials stored:		
A.3.27	Research and Development (R&D) facilities. Describe R&D activities carried out:		

Describe any other processes or activities that you believe should be included as insignificant, and your justification for this belief.

The following units have a PTE less than 5 tpy for all regulated pollutants and less than 1,000 lb/yr for all HAP (See Appendix B of the Application Package):

1) Diesel Storage Tanks (4,000-gallon and 440-gallon)
2) Mechanical Draft Cooling Tower (8 Cells) for NGCCT
3) Lube Oil System with Demister Vents
4) HVAC Heaters (less than 10 MMBtu/hr total)

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-200E

Combustion Source

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of construction, modification, installation, or operation:	3/2024	Control equipment associated with this process equipment:	--

Equipment Description

Emission Process/Point # E50

Manufacturer:	TBD	Model:	TBD
Date of Manufacturer:	TBD	Date of Installation:	3/2024
Firing method:	☐ Direct ☑ Indirect	Rated Maximum Heat Input:	99.9 MMBTU/hr

Fuel Information

Primary Fuel		Secondary Fuel	
☑ Natural Gas	☐ Coal	☐ Natural Gas	☐ Coal
☐ #2 Fuel Oil	☐ #6 Fuel Oil	☐ #2 Fuel Oil	☐ #6 Fuel Oil
☐ Other:		☐ Other:	
Maximum annual consumption:	826.4 MMscf/yr	Maximum annual consumption:	
Maximum firing rate:	99.9 MMBtu/hr	Maximum firing rate:	
Is a low NOx burner used?	☑ Yes ☐ No	Is a low NOx burner used?	☐ Yes ☐ No
If yes, enter rated NOx emission rate:	TBD	If yes, enter rated NOx emission rate:	
Is flue gas recirculation used?	☑ Yes ☐ No	Is flue gas recirculation used?	☐ Yes ☐ No
What percentage of recirculation is used?	TBD %	What percentage of recirculation is used?	%

Ash Handling Information

Is ash handling equipment used?	☐ Yes (Attach mfg spec sheet)	☑ No	
Type of ash handling system	☐ Pneumatic ☐ Mechanical	☐ Hydraulic ☐ Other:	
Ash storage containment system	☐ Storage silo ☐ Trucked off site	☐ Settling Basin ☐ Other:	
Ash generation rate:		On-site ash storage capacity:	

Soot Blowing Information

Is soot blowing conducted?	☐ Yes	☑ No	*If 'Yes,' complete the following*
Frequency of soot blowing: /	Duration :	Time of day:	

Louisville Metro Air Pollution Control District

Permit Application and Renewal
Form AP-200E

Combustion Source

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Louisville, KY 40203

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www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of construction, modification, installation, or operation:	3/2024	Control equipment associated with this process equipment:	--

Equipment Description

Emission Process/Point # E52

Manufacturer:	TBD	Model:	TBD
Date of Manufacturer:	TBD	Date of Installation:	3/2024
Firing method: ☐ Direct ☑ Indirect		Rated Maximum Heat Input:	15 MMBTU/hr

Fuel Information

Primary Fuel	Secondary Fuel
☑ Natural Gas ☐ Coal	☐ Natural Gas ☐ Coal
☐ #2 Fuel Oil ☐ #6 Fuel Oil	☐ #2 Fuel Oil ☐ #6 Fuel Oil
☐ Other:	☐ Other:
Maximum annual consumption: 124.1 MMscf/yr	Maximum annual consumption:
Maximum firing rate: 15 MMBtu/hr	Maximum firing rate:
Is a low NOx burner used? ☐ Yes ☑ No	Is a low NOx burner used? ☐ Yes ☐ No
If yes, enter rated NOx emission rate:	If yes, enter rated NOx emission rate:
Is flue gas recirculation used? ☐ Yes ☑ No	Is flue gas recirculation used? ☐ Yes ☐ No
What percentage of recirculation is used? %	What percentage of recirculation is used? %

Ash Handling Information

Is ash handling equipment used? ☐ Yes (Attach mfg spec sheet) ☑ No

Type of ash handling system	☐ Pneumatic ☐ Mechanical	☐ Hydraulic ☐ Other:	
Ash storage containment system	☐ Storage silo ☐ Trucked off site	☐ Settling Basin ☐ Other:	
Ash generation rate:		On-site ash storage capacity:	

Soot Blowing Information

Is soot blowing conducted? ☐ Yes ☑ No *If 'Yes,' complete the following*

Frequency of soot blowing: /	Duration :	Time of day:

Louisville Metro Air Pollution Control District

Process Permit Application
Form AP-200J

Engine or Generator

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of construction, modification, installation, or operation:	3/2024	Control equipment associated with this process equipment:	C43, C44

Equipment Description

Emission Process/Point # E49a

Manufacturer:	GE 7HA.03, Mitsubishi 501JAC, Siemens 9000HL, or Similar			Model:	TBD
Date of:	Manufacturer - TBD		Installation - 3/2024		Modification - N/A
Type of Engine:	☐ Reciprocating Internal Combustion		☑ Turbine		☐ Other:
Fuel:	☐ Gasoline	☑ Natural Gas		Rated Output:[1] 664,000	☐ HP ☑ kW
	☐ Diesel	☐ Propane	☐ Other:	Maximum Fuel Consumption: 3.981	MMscf/hr

For Reciprocating Internal Combustion Engines

Displacement:				
Number of cylinders:		☐ in-line	☐ V	☐ radical
Ignition source:	☐ spark	☐ compression	☐ Other:	
Engine Type:	☐ 2 stroke	☐ 4 stroke		

Non-resettable hour meter:	☐ Yes ☑ No	Emergency use ?	☐ Yes ☑ No
Output Use	Non –Emergency Equipment	Emergency Equipment	
	Describe: Electricity Distribution	☐ Flood Pump	☐ Electrical Generator
		☐ Fire Pump	☐ Other:
Output device rating:	664 MW		

Fuel Storage Tank Information

☑ No fuel storage tank is required.	Reason: The natural gas fuel will be conveyed to the NGCC unit via pipeline.			
☐ Aboveground	☐ Underground		☐ Vertical	☐ Horizontal
Diameter:	Height or Length:		Working Volume:	
Tank construction	☐ Fiberglass ☐ Plastic	Roof Type	☐ Flat, Fixed	☐ Dome
	☐ Aluminum ☐ Steel		☐ Floating	☐ Other:
Does this tank have a submerged fill pipe, as defined in District regulation 7.12			☐ Yes	☐ No

[1] If this is an engine used to drive an electrial generator, be sure to list the mechanical rating of the engine, NOT the electrical output of the generator. If the output on the engine cannot be determined, multiply the electrical output by 1.1

Federal Regulation Applicability	
Check any Federal regulations which may be applicable to this installation	
☐	40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
☐	40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.
☑	40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.
☑	40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.
☐	40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Louisville Metro Air Pollution Control District

Process Permit Application
Form AP-200J

Engine or Generator

Deliver application to: **Imber**
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of construction, modification, installation, or operation:	3/2024	Control equipment associated with this process equipment:	--

Equipment Description

Emission Process/Point # E51

Manufacturer:	Caterpillar 3516C or Similar			Model:	TBD
Date of:	Manufacturer - TBD	Installation - 3/2024		Modification -	N/A

Type of Engine: ☑ Reciprocating Internal Combustion ☐ Turbine ☐ Other:

Fuel: ☐ Gasoline ☐ Natural Gas ☑ Diesel ☐ Propane ☐ Other:

Rated Output:[1] 2,682 ☑ HP ☐ kW

Maximum Fuel Consumption: 0.137 Mgal/hr

For Reciprocating Internal Combustion Engines

Displacement:	78.1	L
Number of cylinders:	16	☐ in-line ☑ V ☐ radical
Ignition source:	☐ spark ☑ compression ☐ Other:	
Engine Type:	☐ 2 stroke ☑ 4 stroke	

Non-resettable hour meter: ☑ Yes ☐ No

Emergency use ? ☑ Yes ☐ No

Output Use	Non –Emergency Equipment	Emergency Equipment
	Describe: N/A	☐ Flood Pump ☑ Electrical Generator ☐ Fire Pump ☐ Other:

Output device rating: 2,000 kW

Fuel Storage Tank Information

☐ No fuel storage tank is required. Reason:

☐ Aboveground ☐ Underground ☐ Vertical ☐ Horizontal

Diameter: 6.98 ft Height or Length: 13.97 ft Working Volume: 4,000 gal

Tank construction	☐ Fiberglass ☐ Plastic ☐ Aluminum ☐ Steel	Roof Type	☐ Flat, Fixed ☐ Dome ☐ Floating ☐ Other:

Does this tank have a submerged fill pipe, as defined in District regulation 7.12 ☐ Yes ☐ No

1 If this is an engine used to drive an electrial generator, be sure to list the mechanical rating of the engine, NOT the electrical output of the generator. If the output on the engine cannot be determined, multiply the electrical output by 1.1

Federal Regulation Applicability	
Check any Federal regulations which may be applicable to this installation	
☑	40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
☐	40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.
☐	40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.
☐	40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.
☑	40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Louisville Metro Air Pollution Control District

Process Permit Application
Form AP-200J

Engine or Generator

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Louisville, KY 40203

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www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of construction, modification, installation, or operation:	3/2024	Control equipment associated with this process equipment:	--

Equipment Description — Emission Process/Point # IE28

Manufacturer:	Clarke JW6H-UFAD80 or Similar	Model:	TBD
Date of: Manufacturer - TBD	Installation - 3/2024	Modification - N/A	

Type of Engine: ☑ Reciprocating Internal Combustion ☐ Turbine ☐ Other:

Fuel: ☐ Gasoline ☐ Natural Gas ☑ Diesel ☐ Propane ☐ Other:

Rated Output:[1] 400 ☑ HP ☐ kW

Maximum Fuel Consumption: 0.020 Mgal/hr

For Reciprocating Internal Combustion Engines

Displacement:	9	L
Number of cylinders:	6	☑ in-line ☐ V ☐ radical
Ignition source:		☐ spark ☑ compression ☐ Other:
Engine Type:		☐ 2 stroke ☑ 4 stroke

Non-resettable hour meter: ☑ Yes ☐ No

Emergency use ? ☑ Yes ☐ No

Output Use	Non –Emergency Equipment	Emergency Equipment
	Describe: N/A	☐ Flood Pump ☐ Electrical Generator ☑ Fire Pump ☐ Other:

Output device rating: 400 bhp

Fuel Storage Tank Information

☐ No fuel storage tank is required. Reason:

☐ Aboveground ☐ Underground ☐ Vertical ☐ Horizontal

Diameter: 3.35 ft Height or Length: 6.69 ft Working Volume: 440 gal

Tank construction	☐ Fiberglass ☐ Plastic ☐ Aluminum ☐ Steel	Roof Type	☑ Flat, Fixed ☐ Dome ☐ Floating ☐ Other:

Does this tank have a submerged fill pipe, as defined in District regulation 7.12 ☐ Yes ☐ No

[1] If this is an engine used to drive an electrial generator, be sure to list the mechanical rating of the engine, NOT the electrical output of the generator. If the output on the engine cannot be determined, multiply the electrical output by 1.1

Federal Regulation Applicability	
Check any Federal regulations which may be applicable to this installation	
☑	40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
☐	40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.
☐	40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.
☐	40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.
☑	40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Louisville Metro Air Pollution Control District

Control Device Permit Application
Form AP-300A

Generic Control Equipment

Deliver application to:
701 W. Ormsby Ave.Suite 303
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of construction, modification, installation, or operation:	3/2024	Control equipment associated with this process equipment:	Oxidation Catalyst

Equipment Description Control ID# C33

Manufacturer:	TBD	Model:	TBD
Describe Control Equipment operation:	Oxidation catalyst formulated with precious metals and placed in a catalyst bed downstream of the gas turbine exhaust and upstream of the gas turbine SCR catalyst bed.		
Airflow:	TBD acfm	Draft: N/A	Forced Induced
Inlet temperature:	600-1,200 °F	Outlet temperature:	600-750 °F

List the contaminants in the waste stream that are removed by the reduction system:

Contaminant	CAS # (if applicable)	Gas stream concentration	% Control
CO	630-08-0		90%
VOC	N/A		50%
SO_2	7446-09-5		0%
1,3-Butadiene	106-99-0		50%
Acetaldehyde	75-07-0		50%
Acrolein	107-02-8		43%
Benzene	71-43-2		73%
Ethylbenzene	100-41-4		50%
Formaldehyde	50-00-0		68%
Naphthalene	91-20-3		50%
PAH	N/A		50%
Propylene Oxide	75-56-9		50%
Toluene	108-88-3		50%
Xylenes	1330-20-7		50%
Dichlorobenzene	25321-22-6		50%
Hexane	110-54-3		0.5

Describe how the control efficiency was determined:
CO/VOC: Nominal values expected from oxidation catalyst
SO_2: Pages 6-4 & 6-5 of Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update. EPRI, Palo Alto, CA: 2018. 3002012398
HAP: AP-42 Sections 1.4 and 3.1
Refer to Section 5.3 in Appendix B of the application package.

(If other than Manufacturer's specification, include documentation supporting the claimed efficiency)

Describe any monitoring devices, gauges, test ports, etc:

Louisville Metro Air Pollution Control District

Control Device Permit Application
Form AP-300G

Reducing System

Deliver application to:
850 Barret Avenue
Louisville, KY 40203

(502) 574-6000
FAX: (502) 574-5137
www.louisvilleky.gov/apcd
airpermits@louisvilleky.gov

Plant Name:	Louisville Gas & Electric Company - Mill Creek Generating Station	Plant ID:	127
Date of construction, modification, installation, or operation: 3/2024		Process equipment associated with this process equipment:	Selective Catalytic Reduction (SCR)

Equipment Description Control ID# C44

Manufacturer: TBD Model: TBD

Type of System: ☑ Selective catalytic ☐ Selective non-catalytic ☑ Ammonia injection ☐ Non-selective catalytic ☐ Other:

Exhaust gas flow rate: Minimum - 5,604,358 lb/h Maximum - 6,847,000 lb/h Pressure drop - 0.6-1.0 in. w.g.

Attach a copy of the manufacturer's spec sheets for the reduction system with this application

List the components of the waste stream that are removed by the reduction system:

Contaminant	CAS # (if applicable)	Gas steam concentration	% Destruction
NO_X	N/A	< 2 ppmvd	90
SO_2	7446-09-5	Varies	3

Describe how the removal efficiency was determined:
(If other than Manufacturer's specification, include documentation supporting the claimed efficiency)

Operational Information

Ammonia/Urea Injection:	Operating Temperature - 550-700 °F	Allowable ammonia slip - 5 ppm
	Describe how slip is determined: Vendor Guarantees	
	Describe how ammonia injection rate is monitored and controlled: TBD	
Catalytic Reduction	Operating temperature range - 550 -- 700 °F	
	Catalyst used: TiO_2 ceramic substrate with transition metals such as Vanadium, Tungsten, and Molybdenum as activation sites	
	Reducing agent used: 19% Aqueous Ammonia	
	Reducing agent usage rate: 400-700 lb/hr	
	Describe how waste from this operation is handled: TBD	

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ **New** ☐ **Revised** ☒ **for ARP permit renewal**

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Mill Creek Station	KY	0127

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
Unit 1 Boiler 1	Yes
Unit 2 Boiler 2	Yes
Unit 3 Boiler 4	Yes
Unit 4 Boiler 4	Yes
Unit 5, non-peaking natural gas-fired combustion turbine with natural gas-fired duct burners	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission

of a new certificate of representation changing the designated representative;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with

any other provision of the Act, including the provisions of title I of the Act relating

STEP 3, Cont'd.

Effect on Other Authorities, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Steve Turner	
Signature DocuSigned by: Steven B. Turner 8AD647306F3F4A0...	Date 12/15/2022 | 8:20 AM EST

Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the title V permitting authority.

STEP 1 A Plant Code is a 4 or 5 digit number assigned by the Department of Energy=s (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, send an email to the EIA. The email address is EIA-860@eia.gov.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Acid Rain Hotline at (202) 343-9620.

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 8 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

APPENDIX D. SUGGESTED REVISIONS TO PERMIT

To assist APCD in reviewing the application and to promote efficiency in APCD's efforts at preparing a construction permit and revised Title V operating permit, sample suggested edits to the Mill Creek Generating Station's existing Title V permit (O-0127-20-V) (shown in blue font) that reflect the new and modified regulatory and permitting requirements impacted by the NGCC Project are provided in this appendix.

The suggested provisions for new emission units encompass the operating limits, emission standards, and associated compliance assurance monitoring provisions that are derived from applicable regulations and/or are believed to be appropriate to address the permitting requirements triggered by the NGCC Project. LG&E understands that APCD retains the authority and responsibility for developing a construction permit that the agency believes is appropriate for the project. These suggested provisions are only being provided to promote efficiency and timeliness in the agency's review.

Louisville Metro Air Pollution Control District
701 West Ormsby Avenue, Suite 303
Louisville, Kentucky 40203-3137

Title V Operating Permit

Permit No.: O-0127-20-V | Plant ID: 127

Effective Date: 07/27/2020 | Expiration Date: 07/31/2025

Permission is hereby given by the Louisville Metro Air Pollution Control District to operate the process(es) and equipment described herein which are located at:

Source: Louisville Gas & Electric Company
Mill Creek Generating Station
14460 Dixie Highway
Louisville, KY 40272

Owner: Louisville Gas & Electric Company
220 W. Main Street
Louisville, KY 40202

The applicable procedures of District Regulation 2.16 regarding review by the U.S. EPA and public participation have been followed in the issuance of this permit. Based on review of the application on file with the District, permission is given to operate under the conditions stipulated herein. If a renewal permit is not issued prior to the expiration date, the owner or operator may continue to operate in accordance with the terms and conditions of this permit beyond the expiration date, provided that a complete renewal application is submitted to the District no earlier than eighteen months and no later than six months prior to the expiration date.

Application No.: See **Application and Related Documents** table.

Administratively Complete Date: 03/26/2019
Public Notice Date: 06/11/2020
Proposed Permit Date: 06/11/2020

Permit writer: Yiqiu Lin

Air Pollution Control Officer
7/27/2020

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Plantwide Requirements

Facility Description

Louisville Gas & Electric- Mill Creek Generating Station generates electric energy for local and remote distribution. Coal is the primary fuel used to fire commercial boilers for generation of electricity via steam turbines and generators.

Plantwide Applicable Regulations

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
2.16	Title V Operating Permits	1 through 6
40 CFR 52 Subpart A	Approval and Promulgation of Implementation Plans – General Provisions	52.01through 52.39
40 CFR 68 Subpart G	Risk Management Plan	68.150 through 68.195
40 CFR 97 Subpart AAAAA	CSAPR NO_X Annual Trading Program	97.401 through 97.435
40 CFR 97 Subpart GGGGG	CSAPR NOX Ozone Season Group 3 Trading Program	97.1001 through 97.1035
40 CFR 97 Subpart CCCCC	CSAPR SO_2 Group 1 Trading Program	97.601 through 97.635

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.15	Chemical Accident Prevention Provisions	1, 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
STAR regulations are 5.00, 5.01, 5.20, 5.21, 5.22, and 5.23		

Plantwide Specific Conditions

S1. Standards
[Regulation 2.16, Section 4.1.1]

a. **SO_2**

i. The owner or operator shall not allow SO_2 emissions from any of the boilers U1, U2, U3, or U4, to exceed 0.20 lb/MMBtu of heat input based on a rolling 30-day average.[1] [40 CFR 52]

b. **TAC**

i. The owner or operator shall not allow emissions of any TAC to exceed environmentally acceptable (EA) levels, whether specifically established by modeling or determined by the District to be *de minimis*. (See Comment 1) [Regulations 5.00 and 5.21]

ii. The owner or operator shall perform a new Environmental Acceptability (EA) Demonstration or de minimis determination when the following events occur and submit the EA Demonstration on the schedule noted in the reporting section:[2]

(1) An application to construct or modify a process or process equipment is submitted to the District pursuant to Regulation 2.03, 2.04 or 2.05. [Regulation 5.21, section 4.22.1]

(2) A modification of any physical modeling parameters such as fence lines or building heights that are not otherwise subject to the requirements in this permit that affects the demonstration of compliance. [Regulation 5.21, section 4.22.2]; or

(3) A change occurs in the process or process equipment, including raw material or fuel type substitution.
[Regulation 5.21, section 4.22.3]

iii. When a new TAC is introduced or for any existing TAC which does not have an established BAC or *de minimis* value, the owner or operator shall calculate and report these values as part of any aforementioned EA Demonstration. The form, located in Attachment I, may be used for

[1] KDAQ and APCD performed AERMOD modeling for attainment of 1-hour SO_2 NAAQS at LG&E Mill Creek Station. Based on the modeled critical SO_2 emission rate and an established 30-day vs. 1-hour SO_2 emission ratio, the suggested 30-day average critical SO_2 emission rates for each emission unit are determined. APCD believes an average single compliance ratio for all emission units would reasonably reflect the variability of emissions for the whole plant. Also, the same single emission limit for each unit is more conservative since the calculated annual potential total SO_2 emissions based on the single limit 0.20 lb/MMBtu for all units are less than the total SO_2 emissions based on the separate different limit for each unit. On October 20, 2016, LG&E submitted an application form AP-100A and requested the emission standards to be incorporated into its Title V permit.

[2] Changes to the air dispersion modeling program or meteorological data used in the most recent Environmental Acceptability Demonstration do not trigger the requirement to perform a new Environmental Acceptability Demonstration.

determining BAC and *de minimis* values.
[Regulation 5.20, sections 3 and 4]

c. **Cross-State Air Pollution Rule (CSAPR)**[3]

i. The owner or operator shall comply with CSAPR applicable requirements in 40 CFR 97 Subpart AAAAA, Subpart GGGGG, and Subpart CCCCC (See Attachment F).

d. **District Regulation 5.15 Regulated Substance** [40 CFR Part 68 Subpart G]

i. If any toxic substances listed in Tables 1 through 4 to 40 CFR 68.130 are present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall comply with the requirements specified in Regulation 5.15, including the requirement to submit a Risk Management Plan in a method and format as specified by the District and EPA.

S2. Monitoring and Record Keeping
[Regulation 2.16, Section 4.1.9.1 and 4.1.9.2]

The owner or operator shall maintain the following records for a minimum of five years and make the records readily available to the District upon request.

a. **SO_2**

i. See each emission unit (U1, U2, U3, and U4) for the specific monitoring and record keeping requirements.

ii. The owner or operator shall, on a daily basis, monitor and keep records of fuel type, feed rate (or firing rate) of each boiler (U1, U2, U3, and U4).

b. **TAC**

i. The owner or operator shall maintain records sufficient to demonstrate environmental acceptability, including, but not limited to, (M)SDS, analysis of emissions, and/or modeling results.

c. **Cross-State Air Pollution Rule (CSAPR)**

i. The owner or operator shall comply with CSAPR applicable requirements in 40 CFR 97 Subpart AAAAA, Subpart GGGGG, and Subpart CCCCC (See Attachment F).

[3] EPA approved on May 8, 2019 (84 FR 13800) the Kentucky State SIP Revision to replace The Clean Air Interstate Rule (CAIR) with Cross State Air Pollution Rule (CSAPR). CAIR requirements have been removed from the permit.

d. **District Regulation 5.15 Regulated Substance** [40 CFR Part 68, Subpart G]

i. If any toxic substances listed in Tables 1 through 4 to 40 CFR 68.130 are present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall monitor the processes and keep records required by Regulation 5.15.

S3. Reporting
[Regulation 2.16, Section 4.1.1]

The owner or operator shall report the following information, as required by General Condition G14: (See Comment 2)

a. **SO_2**

i. See each emission unit (U1, U2, U3, and U4) for the specific reporting requirements.

ii. Excess emissions for affected facilities (U1, U2, U3, and U4) are defined as: [40 CFR 52]

(1) For affected facilities complying with the 0.20 lb/MMBtu emission standard, any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO2 as measured by a CEMS exceed the standard.

b. **TAC**

i. The owner or operator shall submit new EA Demonstrations involving applications to construct or modify with the construction permit application. [Regulation 5.21, section 4.22.1]

ii. The owner or operator shall submit new EA Demonstrations involving modification of any physical modeling parameter, such as fence lines or building heights, that are not otherwise subject to the permit requirements for that facility that affects the demonstration of compliance with the operating permit renewal application. [Regulation 5.21, section 4.22.2]

iii. The owner or operator shall submit new EA Demonstrations involving a change in a process or process equipment, including raw material or fuel type substitution before making the change.
[Regulation 5.21, section 4.22.3]

(1) Prior approval by the District is not required if the change does not result in emissions that exceed an EA goal, does not cause emissions of a TAC to no longer be de minimis, and a permit modification is

not required. In this case, the new EA Demonstration shall be submitted within 6 months of the change.

c. **Cross-State Air Pollution Rule (CSAPR)**

i. The owner or operator shall comply with CSAPR applicable requirements in 40 CFR 97 Subpart AAAAA, Subpart GGGGG, and Subpart CCCCC (See Attachment F).

d. **District Regulation 5.15 Regulated Substance** [40 CFR Part 68, Subpart G]

i. If any toxic substances listed in Tables 1 through 4 to 40 CFR 68.130 are present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall comply with the reporting requirements specified in Regulation 5.15, including the requirement to submit a Risk Management Plan in a method and format as specified by the District and EPA.

Comments for Plantwide Requirements

1. LG&E Mill Creek submitted their TAC Environmental Acceptability Demonstration to the District on December 28, 2006, March 25, 2008, April 9, 2010, April 2, 2012, May 13, 2014, and January 21, 2016. Compliance with the STAR EA Goals was demonstrated in the source's EA Demonstrations. SCREEN3 air dispersion modeling was performed for each emission unit that has non-de minimis TAC emissions. The following table demonstrates that the carcinogen risk and non-carcinogen risk values, calculated using the District approved PTE for each unit and the SCREEN model results from the source's EA Demonstration, comply with the STAR EA goals required in Regulation 5.21 controlled.

Plantwide Sum	All existing & new		All new P/PE	
Industrial Total R_C	4.16	< 75	0.61	< 38
Non-Ind. Total R_C	4.16	< 7.5	0.61	< 3.8
Industrial Max. R_{NC}	0.16	< 3.0		
Non-Ind. Max. R_{NC}	0.16	< 1.0		

	R_{NC} Total		U1		U2		U3		U4		U8		U9		U22	
	Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.	
TAC	R_{NC}	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}
Total R_C/ Max. R_{NC}	**0.16**	**0.16**	**0.65**		**0.65**		**1.09**		**1.07**		**0.58**		**0.10**		**0.03**	
Ar &compounds	0.03	0.03	0.29	0.00	0.29	0.00	0.48	0.01	0.48	0.01	0.56	0.01	0.10	0.002	0.02	0.00
Cd &compounds	0.00	0.00	0.02	0.00	0.02	0.00	0.03	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cr IV&compounds	0.02	0.02	0.28	0.00	0.28	0.00	0.48	0.00	0.47	0.00	000	000	0.00	0.00	0.00	0.00
Cr III &compounds	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Formaldehyde	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ni & compounds	0.03	0.03	0.02	0.01	0.02	0.01	0.03	0.01	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Co & compounds	0.01	0.01	0.03	0.00	0.03	0.00	0.06	0.00	0.06	0.00	0.03	0.001	0.00	0.00	0.00	0.00
Hydrofluoric acid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pb & compounds	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mn & compounds	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Naphthalene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sulfuric acid	0.16	0.16	0.00	0.03	0.00	0.03	0.00	0.05	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00

2. The compliance reports are due on or before the following dates of each calendar year:

Reporting Period	Report Due Date
January 1st through March 31th	May 30th
April 1st through June 30th	August 29th
July 1st through September 30th	November 29th
October 1st through December 31st	March 1st

Emission Unit U1: Electric Utility Steam Generating Unit (EGU) – Unit 1

Applicable Regulations

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.07	Standards of Performance for Existing Indirect Heat Exchangers	1, 2, 3, 4
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
40 CFR 64	Compliance Assurance Monitoring for Major Stationary Sources	64.1 through 64.10
40 CFR 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6
40 CFR 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20
40 CFR 63 Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (EGU MACT)	63.9980 through 63.10042

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.02	Adoption of National Emission Standards for Hazardous Air Pollutants	1, 3.95 and 4
5.14	Hazardous Air Pollutants and Source Categories	1, 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
STAR regulations are 5.00, 5.01, 5.20, 5.21, 5.22, and 5.23		

Equipment

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
E1	One (1) tangentially fired boiler, rated capacity 3,085 MMBtu/hr, make Combustion Engineering, using pulverized coal as a primary fuel and natural gas as secondary fuel.	1970	STAR, 5.02, 5.14, 6.02, 6.07, 6.42, 6.47, 40CFR64, 40CFR72-73, 40CFR75-78, 40CFR63UUUUU	C1, C26, C27	S33
E2	Four (4) coal silos, make Fisher-Klosterman, controlled by a centrifugal dust collector and equipped with four (4) coal mills, make Combustion Engineering Raymond Bowl Mills.	1970	STAR, 6.09	C3	S5

Control Devices

Control ID	Description	Control Efficiency	Performance Indicator
C1	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	N/A	N/A [4]

[4] This unit is equipped with CEMS for NOx, SO2, and PM. According to the District's letter dated November 1, 2005, parametric monitoring of the ESP, FGD, and PJFF for this unit is removed as such monitoring would no longer be required for demonstration of compliance. On July 22, 2016, LG&E reported the normal pressure drop range for U1 PJFF, 2 – 6 inches of water, established during 90 consecutive operating days.

Control ID	Description	Control Efficiency	Performance Indicator
C3	One (1) centrifugal dust collector, make Fisher-Klosterman	90%	N/A[5]
C26	One (1) HAP particulate matter control system, consists of: one (1) powdered activated carbon (PAC) injection system; one (1) dry sorbent injection system; liquid additive system(s); and one (1) pulse-jet fabric filter (PJFF) baghouse used for collecting PM from the boiler and PAC and dry sorbent injection system. PJFF baghouse make Clyde Bergemann Power Group, model Structural Pulse Jet	H_2SO_4:[6] 98.7% Hg: 89.3% PM: 99.2%	PM Control: PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance) Hg control: (1) Minimum PAC injection rate; [7] (2) pH of reactant in FGD, 4.8-6.4; (3) Hg emission data from Sorbent Traps
C27	One (1) combined Flue Gas desulfurization (FGD) unit for SO2 control using limestone scrubbing liquor, make Babcock Power Environmental	N/A	N/A[4]

[5] For the coal silos (E2), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

[6] Control efficiencies of C26 are based on stack test conducted on June 4-8, 2015.

[7] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore, the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

U1 Specific Conditions

S1. Standards [8]
[Regulation 2.16, Section 4.1.1]

a. **BART** [40 CFR 52, Subpart S]

i. The owner or operator shall continue to utilize PJFF baghouse and/or existing ESP to control PM emissions for this unit.[9]
[40 CFR 52.920(e) refer to Kentucky Regional Haze SIP]

b. **HAP** [40 CFR 63 Subpart UUUUU]

i. The owner or operator shall comply with emission standards required in 40 CFR 63 Subpart UUUUU (See Attachment A).

c. **NO_x**

i. The owner or operator shall not allow the average NO_x emissions to exceed the alternate contemporaneous emission limitation of 0.40 lb/MMBtu of heat input on an annual average basis, as specified in Acid Rain Permit No.176-97-AR (R5) which is attached and considered part of the Title V Operating Permit. (See Acid Rain Permit Attachment)
[Regulation 6.47, section 3.5 referencing 40 CFR Part 76]

ii. The owner or operator shall not exceed the NOx RACT emissions standard of 0.47 lb/MMBtu of heat input based on a rolling 30-day average. (See NOx RACT, Attachment D) [Regulation 6.42, section 4.3]

iii. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas.
[Regulation 6.02, section 6.1.3] [NO_x RACT Plan] [Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2)]

d. **Opacity**

i. The owner or operator shall not cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except emissions into the open air of particulate matter from any indirect heat exchanger during building a new fire, cleaning the fire box, or blowing soot for a period or periods aggregating not more than ten

[8] The emission standards, monitoring, record keeping, and reporting requirements only apply to boiler E1 (not coal silos E2) unless otherwise noted.
[9] On March 30, 2012, EPA finalized a limited approval and a limited disapproval of the Kentucky state implementation plan submitted on June 25, 2008 and May 28, 2010. According to 40 CFR 52.920(e), the owner or operator shall meet BART requirements summarized in Table 7.5.3-2 of the Commonwealth's May 28, 2010 submittal.

minutes in any 60 minutes which are less than 40% opacity.
[Regulation 6.07, section 3.2 and 3.3]

ii. The company shall follow one of the two options in the table under Specific Condition for PM to demonstrate compliance with opacity standards.

iii. For coal silos (E2), the owner or operator shall not allow visible emissions to equal or exceed 20% opacity. [Regulation 6.09, section 3.1]

e. **PM**

i. The owner or operator shall not exceed an allowable particulate emission rate of 0.11 lbs/MMBtu heat input based on a 3-hour rolling average. [Regulation 6.07, section 3.1]

ii. At all time, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate boiler E1 including associated PM control equipment (PJFF) in a manner consistent with good air pollution control practice for minimizing emissions. Following commissioning of the PJFF baghouses, the owner or operator may elect to operate, turn down, or turn off the ESP to ensure the efficient operation of the PJFF baghouse.[10]
[Regulation 1.05, section 5]

iii. The company shall follow one of the two options below to demonstrate compliance with PM standards:

Compliance Options	PM	Opacity	Control Device Performance indication
Option 1	Certified PM CEMS	VE/Method 9, or Certified COMS	N/A
Option 2	Annual testing	Certified COMS	PM CEMS

iv. For coal silos (E2), the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr from four coal silos combined based on actual operating hours in a calendar day.[11]
[Regulation 6.09, section 3.2]

[10] The PM emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for PM.

[11] For the coal silos (E2), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

f. **SO_2**

i. The owner or operator shall not exceed 1.2 lb/MMBtu per hour heat input based on a 3-hour rolling average. [Regulation 6.07, section 4.1]

ii. The owner or operator shall comply with the SO_2 emission allowances specified in Acid Rain Permit No.176-97-AR (R5). (See Acid Rain Permit Attachment) [Regulation 6.47, section 3.2 referencing 40 CFR Part 73]

iii. At all time, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate boiler E1 including associated SO_2 control equipment (FGD) in a manner consistent with good air pollution control practice for minimizing emissions.[12] [Regulation 1.05, section 5]

iv. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement of sulfur dioxide in the flue gas.
[Regulation 6.02, section 6.1.2] [Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1)]

g. **TAC**

i. The owner or operator shall not allow TAC emissions from boiler E1 to exceed the TAC emission standards determined based upon the EA Demonstration provided to the District.[13] (See Comment 1)
[Regulation 5.21, section 4.2 and section 4.3]

TAC Name	CAS #	TAC Limits Determination	
		(lbs/yr)	Basis of Limits
Naphthalene	91-20-3	16.6	Controlled PTE
Formaldehyde	50-00-0	70.3	Controlled PTE
Hydrogen fluoride	7664-39-3	13,385	Controlled PTE
Arsenic compounds	7440-38-2	266	Controlled PTE
Cadmium compounds	7440-43-9	42.1	Controlled PTE
Chromium VI	7440-47-3	94.5	Controlled PTE
Chromium III	16065-83-1	216	Controlled PTE
Cobalt compounds	7440-48-4	56.2	Controlled PTE
Lead compounds	7439-92-1	332	Controlled PTE

[12] The SO2 emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for SO2.
[13] This table for TAC emission standards has been revised to exclude Category 3 and 4 TACs for existing sources and use "de minimis values", instead of actual numbers for current de minimis levels, as emission standards.

TAC Name	CAS #	TAC Limits Determination	
		(lbs/yr)	Basis of Limits
Manganese compounds	7439-96-5	424	Controlled PTE
Nickel compounds	7440-02-0	307	Controlled PTE
Sulfuric acid	7664-93-9	118,679	Controlled PTE
Benzene	71-43-2	De minimis values (See Comment 1)	De Minimis
Bromoform	75-25-2		De Minimis
Chloroform	67-66-3		De Minimis
Methylene chloride	75-09-2		De Minimis
Tetrachloroethylene (Perc)	127-18-4		De Minimis
Toluene	108-88-3		De Minimis
Xylene	1330-20-7		De Minimis
Hydrochloric acid	7647-01-0		De Minimis

ii. See Plantwide Requirements.

h. **Unit Operation**

i. The owner or operator shall shut down the existing emission unit U1 prior to the date when the new emission unit U23 becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days. (Regulation 2.05)

S2. Monitoring and Record Keeping
[Regulation 2.16, Section 4.1.9.1 and 4.1.9.2]

The owner or operator shall maintain the following records for a minimum of five years and make the records readily available to the District upon request.

a. **BART** [40 CFR 52, Subpart S]

i. The owner or operator shall maintain daily records of any periods of time where the process was operating and both PJFF baghouse and ESP were not operating or a declaration that the PJFF baghouse and/or ESP operated at all times that day when the process was operating.

b. **HAP** [40 CFR 63 Subpart UUUUU]

i. The owner or operator shall comply with monitoring and record keeping requirements in 40 CFR 63 Subpart UUUUU. (See Attachment A)

ii. The owner or operator shall establish a site-specific minimum activated carbon injection rate for PAC injection system according to Attachment B.[14] The owner or operator shall monitor and record the activated carbon injection rate during each operating day.

iii. The owner or operator shall monitor and record all Hg emission data from the Hg sorbent traps, which is used as the indicator of normal operation of the Hg control measures.

iv. The owner or operator shall monitor and record the pH of the reactant material in the FGD and any other parameters verified as having a direct effect on Hg emissions during each operating day, which is (are) used as the indicator(s) of normal operation of Hg control measures.[15]

v. The owner or operator shall maintain records of which Hg control devices/measure was being used during each operating day.

c. **NO_x**

i. The owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan. (See NO_x RACT Attachment) [Regulation 6.42, section 4.3]

ii. The owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

iii. The owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR (R5). These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F. (See Appendix A to NOx RACT Plan) [Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76]

iv. The owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75, section 75.57(d). For each NO_x emission rate (in lb/mmBtu) measured by a NO_x-diluent monitoring system, or, if applicable, for each NO_x concentration (in ppm) measured by a NO_x concentration monitoring system used to calculate NO_x mass emissions under 40 CFR 75.71(a)(2), record the following data as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

[14] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

[15] LG&E has established normal pH range per monitoring records during consecutive 180 days. On 10/20/2016, LG&E reported that the normal pH range for this unit is 4.8 – 6.4.

(1) Component-system identification code, as provided in 40 CFR 75.53 (including identification code for the moisture monitoring system, if applicable); [40 CFR 75.57(d)(1)]

(2) Date and hour; [40 CFR 75.57(d)(2)]

(3) Hourly average NOx concentration (ppm, rounded to the nearest tenth) and hourly average NOx concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); [40 CFR 75.57(d)(3)]

(4) Hourly average diluent gas concentration (for NOx -diluent monitoring systems, only, in units of percent O_2 or percent CO_2, rounded to the nearest tenth); [40 CFR 75.57(d)(4)]

(5) If applicable, the hourly average moisture content of the stack gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O_2, rounded to the nearest tenth);
[40 CFR 75.57(d)(5)]

(6) Hourly average NOx emission rate (for NOx -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth); [40 CFR 75.57(d)(6)]

(7) Hourly average NOx emission rate (for NOx -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d). The requirement to report hourly NOx emission rates to the nearest thousandth shall not affect NOx compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu;
[40 CFR 75.57(d)(7)]

(8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NOx -diluent or NOx concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to 40 CFR 75.32; [40 CFR 75.57(d)(8)]

(9) Method of determination for hourly average NOx emission rate or NOx concentration and (if applicable) for the hourly average moisture percentage, using Codes 1–55 in Table 4a of 40 CFR 75.57; and [40 CFR 75.57(d)(9)]

(10) Identification codes for emissions formulas used to derive hourly average NOx emission rate and total NOx mass emissions, as provided in 40 CFR 75.53, and (if applicable) the F-factor used to convert NOx concentrations into emission rates.
[40 CFR 75.57(d)(10)]

v. A CEMS for measuring either oxygen (O_2) or carbon dioxide (CO_2) in the flue gases shall be installed, calibrated, maintained, and operated by the owner or operator. [Regulation 6.02, section 6.1.3] (NO_x RACT Plan)

vi. The owner or operator shall monitor the NO_x emissions, the NO_x allowances, as specified in the applicable NO_x cap and trade program(s) in effect.

vii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	**Span value for NO_X**
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

viii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards.

(1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(a) E = pollutant emissions, ng/J (lb/MMBtu).

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), $F = 2{,}723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and $F_c = 0.532 \times 10^{-17}$ scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), $F = 2.637 \times 10^{-7}$ dscm/J (9,820 dscf/MMBtu) and $F_c = 0.486 \times 10^{-7}$ scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/MMBtu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, $F = 2.347 \times 10^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark $F = 2.589 \times 10^{-7}$ dscm/J (9,640 dscf/MMBtu) and $F_c = 0.500 \times 10^{-7}$ scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark $F = 2.492 \times 10^{-7}$ dscm/J (9,280 dscf/MMBtu) and $F_c = 0.494 \times 10^{-7}$ scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), $F = 2.659 \times 10^{-7}$ dscm/J (9,900 dscf/MMBtu) and $F_c = 0.516 \times 10^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu).

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6} \frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}\ (\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6} \frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321 \times 10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:

X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);

F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

d. **Opacity**

i. If certified COMS is used to demonstrate compliance with opacity standards, the owner or operator shall record on an hourly basis all opacity from COMS.[16]

ii. If VE/Method 9 is used to demonstrate compliance with opacity standards, in order for the owner or operator to use its VE observations to satisfy the opacity monitoring requirement, the following conditions must be met:[16] (EPA Letter, 2007)

(1) On a weekly basis, the owner or operator shall attempt to perform VE observations in accordance with procedures in EPA Method 9.

(2) On the weeks when it is possible to collect unit-specific VE data, at least one hour of Method 9 data shall be collected for each unit.

(3) Records of the Method 9 readings shall be submitted with the quarterly excess emission reports for PM emissions.

iii. The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day.

iv. <u>For coal silos (E2):</u>

(1) The owner or operator shall, weekly, conduct a one-minute visible emissions survey, during normal operation, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation.

(2) At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

(3) The owner or operator shall, monthly, maintain records of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible

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[16] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

e. **PM**

i. The company shall follow one of the two options below to demonstrate compliance with PM standards:

(1) Option 1: the owner or operator shall install, maintain, calibrate, and operate a PM CEMS for each steam generating unit. [17, 18] [Regulation 2.16, section 4.1.1] [40 CFR 64]

(a) The use of PM CEMS as the measurement technique must be appropriate for the stack conditions.

(b) The PM CEMS must be installed, operated and maintained in accordance with the manufacturer's recommendations.

(c) The PM CEMS must be certified in accordance with Performance Specification 11, Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources, found in 40 CFR 60 Appendix B.

(d) A quality assurance/quality control program must be implemented in accordance with procedures in 40 CFR 60 Appendix F, Procedure 2 (Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources).

(e) Compliance with the particulate matter emission limit will be based upon 3-hour rolling average periods during source operation.

(f) Quarterly excess emission reports must be submitted, and PM excess emissions shall be reported based upon 3-hour rolling averages during source operation.

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[17] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

[18] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 3/20/2020, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

(2) Option 2: the owner or operator shall conduct an annual EPA Reference Method 5 performance test following the testing requirements in Attachment B.

ii. If certified PM CEMS (Option 1) is used to demonstrate compliance with PM standards, the owner or operator shall record on an hourly basis all PM emission data, in lb/MMBtu, from PM CEMS.[19] [40 CFR 64]

iii. If annual PM testing (Option 2) is used to demonstrate compliance with PM standards, the owner or operator shall use PM CEMS as a performance indicator of continuous normal operation of the PM control devices and do the following:[19] [40 CFR 64]

(1) The owner or operator shall monitor and record all PM emission data from PM CEMS, which is used as the indicator of normal operation of the PM control devices.

(2) The owner or operator shall maintain daily records of any periods of time where the process was operating and the PM control devices were not operating or a declaration that the PM control devices operated at all times that day when the process was operating.

(3) If there is any time that the PM control devices are bypassed or not in operation when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

(a) Date;

(b) Start time and stop time;

(c) Identification of the control devices and process equipment;

(d) PM emissions during the bypass in lb/hr;

(e) Summary of the cause or reason for each bypass event;

(f) Corrective action taken to minimize the extent or duration of the bypass event; and

(g) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

f. **SO_2**

i. The owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

[19] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 3/20/2020, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

ii. The owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.57(c): [40 CFR 64]

(1) For SO_2 concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: [40 CFR 75.57(c)(1)]

(a) Component-system identification code, as provided in 40 CFR 75.53; [40 CFR 75.57(c)(1)(i)]

(b) Date and hour; [40 CFR 75.57(c)(1)(ii)]

(c) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth); [40 CFR 75.57(c)(1)(iii)]

(d) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d); [40 CFR 75.57(c)(1)(iv)]

(e) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to 40 CFR 75.32; and [40 CFR 75.57(c)(1)(v)]

(f) Method of determination for hourly average SO_2 concentration using Codes 1–55 in Table 4a of 40 CFR 75.57. [40 CFR 75.57(c)(1)(vi)]

(2) For flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: [40 CFR 75.57(c)(2)]

(a) Component-system identification code, as provided in 40 CFR 75.53; [40 CFR 75.57(c)(2)(i)]

(b) Date and hour; [40 CFR 75.57(c)(2)(ii)]

(c) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand); [40 CFR 75.57(c)(2)(iii)]

(d) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); [40 CFR 75.57(c)(2)(iv)]

(e) Percent monitor data availability (recorded to the nearest tenth of a percent) for the flow monitor, calculated pursuant to 40 CFR 75.32; and [40 CFR 75.57(c)(2)(v)]

(f) Method of determination for hourly average flow rate using Codes 1–55 in Table 4a of 40 CFR 75.57. [40 CFR 75.57(c)(2)(vi)]

(3) For SO_2 mass emission rate during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: [40 CFR 75.57(c)(4)]

(a) Date and hour; [40 CFR 75.57(c)(4)(i)]

(b) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth); [40 CFR 75.57(c)(4)(ii)]

(c) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); and [40 CFR 75.57(c)(4)(iii)]

(d) Identification code for emissions formula used to derive hourly SO2 mass emission rate from SO2 concentration and flow and (if applicable) moisture data in paragraphs (c)(1), (c)(2), and (c)(3) of 40 CFR 75.57, as provided in 40 CFR 75.53. [40 CFR 75.57(c)(4)(iv)]

iii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	**Span value for NO_X**
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

iv. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards.

(1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(a) E = pollutant emissions, ng/J (lb/MMBtu).

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = $2{,}723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532×10^{-17} scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.637×10^{-7} dscm/J (9,820 dscf/MMBtu) and F_c= 0.486×10^{-7} scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476×10^{-7} dscm/J (9,220 dscf/MMBtu) and F_c= 0.384×10^{-7} scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347×10^{-7} dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279×10^{-7} scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589×10^{-7} dscm/J (9,640 dscf/MMBtu) and F_c= 0.500×10^{-7} scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492×10^{-7} dscm/J (9,280 dscf/MMBtu) and F_c= 0.494×10^{-7} scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17),

$F = 2.659 \times 10^{-7}$ dscm/J (9,900 dscf/MMBtu) and $F_c = 0.516 \times 10^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu).

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0\times10^{-5}\,(\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321\times10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:

X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);

F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

g. **TAC**

i. The owner or operator shall, monthly, calculate and record TAC emissions for this unit in order to demonstrate compliance with the TAC emission standards.

ii. See Plantwide Requirements.

S3. Reporting

[Regulation 2.16, Section 4.1.1]

The owner or operator shall report the following information, as required by General Condition G14:

a. **BART** [40 CFR 52, Subpart S]

i. The owner or operator shall report any periods of time where the process was operating and both PJFF baghouse and ESP were not operating.

b. **HAP** [40 CFR 63 Subpart UUUUU]

i. The owner or operator shall comply with reporting requirements in 40 CFR 63 Subpart UUUUU. (See Attachment A)

ii. Report normal pH range of reactant material in the FGD and normal range of any other parameters verified as having a direct effect on Hg emission within 30 days of establishing the normal range.

iii. The owner or operator shall identify all periods of the activated carbon injection rate are less than the minimum injection rate, or the pH of the reactant material in the FGD are out of normal range, or anytime other verified parameters are outside of their normal range, and any corrective action taken for each exceedance.

c. **NO_x**

i. The owner or operator shall identify all periods of exceeding a NO_x emission standard during a quarterly reporting period. The quarterly compliance report shall include the following:

(1) Emission Unit ID number and emission point ID number;

(2) Identification of all periods during which a deviation occurred;

(3) A description, including the magnitude, of the deviation;

(4) If known, the cause of the deviation;

(5) A description of all corrective actions taken to abate the deviation; and

(6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the pollutant/source category in question. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. The required report shall include:
[Regulation 6.02, section 16.1]

(1) For gaseous measurements, the summary shall consist of hourly averages in the units of the applicable standard. The hourly averages shall not appear in the written summary, but shall be made available electronically.[20] [Regulation 6.02, section 16.3]

(2) The data and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustment shall be reported. Proof of continuous monitoring system performance whenever system repairs or adjustments have been made is required. [Regulation 6.02, section 16.4]

(3) When no excess emissions have occurred and the continuous monitoring systems have been inoperative, repaired, or adjusted, such information shall be included in the report.
[Regulation 6.02, section 16.5]

(4) Owners or operators of affected facilities shall maintain a file of all information reported in the quarterly summaries, and all other data collected either by the continuous monitoring system or as necessary to convert monitoring data to the units of the applicable standard for a minimum of two years from the date of collection of such data or

[20] The hourly averages are only required to be made available in electronic summary, not in written summary.

submission of such summaries.
[Regulation 6.02, section 16.6]

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R5), specified in 40 CFR 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator[21], and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)

iv. The owner or operator shall comply with the reporting requirements for the Title IV NO_x Budget Emission Limitation, 0.40 lb/MMBtu, as specified in 40 CFR Part 76.

v. Excess emissions for affected facilities using a CEMS for measuring NO_X are defined as: [Regulation 2.16, section 4.1.9.3]

(1) Any annual average period during which the average emissions (arithmetic average of all one-hour period during the 12 month period) of NOx as measured by a CEMS exceed the applicable standard.

(2) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_X as measured by a CEMS exceed the applicable standard.

d. **Opacity**

i. The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

(1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests and documented reason;

(2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed and documented reason;

(3) The number, date, and time of each VE Survey where visible emissions were observed and the results of the Method 9 test performed;

(4) Identification of all periods of exceeding an opacity standard;

(5) Description of any corrective action taken for each exceedance of the opacity standard; or

[21] In this permit, Administrator means the District.

(6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R5), specified in 40 CFR 75 Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)
[Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76]

iii. For coal silos (E2):

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

(1) Emission Unit ID number, Stack ID number, and/or Emission point ID number;

(2) The beginning and ending date of the reporting period;

(3) The date, time and results of each exceedance of the opacity standard;

(4) Description of any corrective action taken for each exceedance.

e. **PM**

i. The owner or operator shall identify all periods of exceeding a PM emission standard during a quarterly reporting period. The report shall include the following:

(1) Emission Unit ID number and emission point ID number;

(2) The date and duration (including the start and stop time) during which a deviation occurred;

(3) The magnitude of excess emissions;

(4) Description of the deviation and summary information on the cause or reason for excess emissions;

(5) Corrective action taken to minimize the extent and duration of each excess emissions event;

(6) Measures implemented to prevent reoccurrence of the situation that resulted in excess PM emissions; or

(7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known.

f. **SO_2**

i. The owner or operator shall identify all periods of exceeding a SO_2 emission standard during a quarterly reporting period. The report shall include the following:

(1) Emission Unit ID number and emission point ID number;

(2) Identification of all periods during which a deviation occurred;

(3) A description, including the magnitude, of the deviation;

(4) If known, the cause of the deviation;

(5) A description of all corrective actions taken to abate the deviation; and

(6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known.

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R5), specified in 40 CFR 75 Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - Reporting Requirements. (See Attachment E)

iv. Excess emissions for affected facilities using a CEMS for measuring SO_2 are defined as: [Regulation 2.16, section 4.1.9.3]

(1) Any 3-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard; or

(2) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard.

g. **TAC**

i. The owner or operator shall identify all periods of exceeding a TAC emission standard during a quarterly reporting period. The report shall include the following:

(1) Emission Unit ID number and emission point ID number;

(2) Identification of all periods during which a deviation occurred;

(3) A description, including the magnitude, of the deviation;

(4) If known, the cause of the deviation;

(5) A description of all corrective actions taken to abate the deviation; and

(6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. See Plantwide Requirements.

S4. Testing
[Regulation 2.16, section 4.3.1]

a. **Control efficiency determination**

i. The owner or operator shall conduct performance test for the new EGU control device C26 and C27, according to the testing requirements in Attachment B, C and H.[22, 23] [Regulation 2.16, section 4.1.9.1]

ii. The owner or operator shall conduct a subsequent performance test to determine the control efficiency for sulfuric acid (H_2SO_4) by June 3, 2025, according to the testing requirements in Attachment B and C.[24] [Regulation 2.16, section 4.1.9.1]

U1 Comments

1. Boiler (E1) has TAC emission standards since its EA Demonstration was based on controlled PTE. If the controlled PTE for the TAC is less than de minimis level, use De Minimis as limit. If the controlled PTE for the TAC is greater than de minimis level, modeling results were used to calculate risk value to compare to the EA Goals. In this case, controlled PTE is used as limit. TAC emissions for the coal silos (E2) are de minimis according to Regulation 5.21, section 2.1. The TAC emission limits determined by de minimis values shall be updated each time when the District revises the BAC/de minimis values for these TACs. The current de minimis values per TAC list revised on 11/9/2017 are as the following:

TAC Name	CAS #	De minimis values		
		(lb/hr)	(lb/Ave Period)	(lb/yr)
Benzene	71-43-2	0.24		216

[22] Per an EPA rule change ("Restructuring of the Stationary Source Audit Program." Federal Register 75:176 (September 13, 2010) pp 55636-55657), if an audit sample is required by the test method, sources became responsible for obtaining the audit samples directly from accredited audit sample suppliers, not the regulatory agencies.

[23] This unit was modified under construction permit 34595-12-C. According to permit 34595-12-C, the source is required to conduct stack tests to obtain actual emission factors and control efficiencies. Control efficiencies stack test for C26 and C27 were conducted on June 4-8, 2015.

[24] Compliance with STAR Program for sulfuric acid was based on controlled sulfuric acid emissions. The source shall use the updated control efficiency to calculate actual sulfuric acid emissions.

TAC Name	CAS #	De minimis values		
		(lb/hr)	(lb/Ave Period)	(lb/yr)
Bromoform	75-25-2	0.49		437
Chloroform	67-66-3	0.023		20.64
Methylene chloride	75-09-2	54		48,000
Tetrachloroethylene (Perc)	127-18-4	2.08		1,848
Toluene	108-88-3	2700	2,400,000 lb/yr	
Xylene	1330-20-7	54	48,000 lb/yr	
Hydrochloric acid	7647-01-0	10.8	9,600 lb/yr	

Emission Unit U2: Electric Utility Steam Generating Unit (EGU) – Unit 2

Applicable Regulations

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.07	Standards of Performance for Existing Indirect Heat Exchangers	1, 2, 3, 4
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
40 CFR 64	Compliance Assurance Monitoring for Major Stationary Sources	64.1 through 64.10
40 CFR 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6
40 CFR 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20
40 CFR 63 Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (EGU MACT)	63.9980 through 63.10042

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.02	Adoption of National Emission Standards for Hazardous Air Pollutants	1, 3.95 and 4
5.14	Hazardous Air Pollutants and Source Categories	1, 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
STAR regulations are 5.00, 5.01, 5.20, 5.21, 5.22, and 5.23		

Equipment

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
E3	One (1) tangentially fired boiler, rated capacity 3,085 MMBtu/hr, make Combustion Engineering, using pulverized coal as a primary fuel and natural gas as secondary fuel.	1970	STAR, 5.02, 5.14, 6.02, 6.07, 6.42, 6.47, 40CFR64, 40CFR72-73, 40CFR75-78, 40CFR63 UUUUU	C4, C27, C28	S33
E4	Four (4) coal silos, make American Air Filter, controlled by a centrifugal dust collector and equipped with four (4) coal mills, make Combustion Engineering Raymond Bowl Mills.	1970	STAR, 6.09	C6	S6

Control Devices

Control ID	Description	Control Efficiency	Performance Indicator
C4	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	N/A	N/A [25]

[25] This unit is equipped with CEMS for NOx, SO2, and PM. According to the District's letter dated November 1, 2005, parametric monitoring of the ESP, FGD, and PJFF for this unit is removed as such monitoring would no longer be required for demonstration of compliance. On July 22, 2016, LG&E reported the normal pressure drop range for U2 PJFF, 2 – 6 inches of water, established during 90 consecutive operating days.

Control ID	Description	Control Efficiency	Performance Indicator
C6	One (1) centrifugal dust collector, make American Air Filter	90%	N/A[26]
C27	One (1) combined Flue Gas desulfurization (FGD) unit for SO2 control using limestone scrubbing liquor, make Babcock Power Environmental	N/A	N/A[25]
C28	One (1) HAP particulate matter control system, consists of: one (1) powdered activated carbon (PAC) injection system; one (1) dry sorbent injection system; liquid additive system(s); and one (1) pulse-jet fabric filter (PJFF) baghouse used for collecting PM from the boiler and PAC and dry sorbent injection system. PJFF make Clyde Bergemann Power Group, model Structural Pulse Jet	H2SO4:[27] 99.8% Hg: 85.5% PM: 99.5%	PM Control: PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance) Hg control: (1) Minimum PAC injection rate;[28] (2) pH of reactant in FGD, 4.8-6.4; (3) Hg emission data from Sorbent Traps

[26] For the coal silos (E4), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

[27] Control efficiencies of C28 are based on stack test conducted on June 4-8, 2015.

[28] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore, the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

U2 Specific Conditions

S1. Standards [29]
[Regulation 2.16, Section 4.1.1]

a. **BART** [40 CFR 52, Subpart S]

i. The owner or operator shall continue to utilize PJFF baghouse and/or existing ESP to control PM emissions for this unit.[30]
[40 CFR 52.920(e) refer to Kentucky Regional Haze SIP]

b. **HAP** [40 CFR 63 Subpart UUUUU]

i. The owner or operator shall comply with emission standards required in 40 CFR 63 Subpart UUUUU (See Attachment A).

c. **NO_x**

i. The owner or operator shall not allow the average NO_x emissions to exceed the alternate contemporaneous emission limitation of 0.40 lb/MMBtu of heat input on an <u>annual</u> average basis, as specified in Acid Rain Permit No.176-97-AR (R5) which is attached and considered part of the Title V Operating Permit. (See Acid Rain Permit Attachment)
[Regulation 6.47, section 3.5 referencing 40 CFR Part 76]

ii. The owner or operator shall not exceed the NOx RACT emissions standard of 0.47 lb/MMBtu of heat input based on a rolling <u>30-day</u> average. (See NOx RACT, Attachment D) [Regulation 6.42, section 4.3]

iii. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas.
[Regulation 6.02, section 6.1.3] [NO_x RACT Plan] [Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2)]

d. **Opacity**

i. The owner or operator shall not cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except emissions into the open air of particulate matter from any indirect heat exchanger during building a new fire, cleaning the fire box, or blowing soot for a period or periods aggregating not more than ten

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[29] The emission standards, monitoring, record keeping, and reporting requirements only apply to the boiler E3 (not the coal silos E4) if not indicated.

[30] On March 30, 2012, EPA finalized a limited approval and a limited disapproval of the Kentucky state implementation plan submitted on June 25, 2008 and May 28, 2010. According to 40 CFR 52.920(e), the owner or operator shall meet BART requirements summarized in Table 7.5.3-2 of the Commonwealth's May 28, 2010 submittal.

minutes in any 60 minutes which are less than 40% opacity.
[Regulation 6.07, section 3.2 and 3.3]

ii. The company shall follow one of the two options in the table under Specific Condition for PM to demonstrate compliance with opacity standards.

iii. For coal silos (E4), the owner or operator shall not allow visible emissions to equal or exceed 20% opacity. [Regulation 6.09, section 3.1]

e. **PM**

i. The owner or operator shall not exceed an allowable particulate emission rate of 0.11 lbs/MMBtu heat input based on a 3-hour rolling average. [Regulation 6.07, section 3.1]

ii. At all time, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate boiler E3 including associated PM control equipment (PJFF) in a manner consistent with good air pollution control practice for minimizing emissions. Following commissioning of the PJFF baghouses, the owner or operator may elect to operate, turn down, or turn off the ESP to ensure the efficient operation of the PJFF baghouse.[31]
[Regulation 1.05, section 5]

iii. The company shall follow one of the two options below to demonstrate compliance with PM standards:

Compliance Options	PM	Opacity	Control Device Performance indication
Option 1	Certified PM CEMS	VE/Method 9, or Certified COMS	N/A
Option 2	Annual testing	Certified COMS	PM CEMS

iv. For coal silos (E4), the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr from four coal silos combined based on actual operating hours in a calendar day.[32]
[Regulation 6.09, section 3.2]

[31] The PM emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for PM.

[32] For the coal silos (E2), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

f. **SO_2**

i. The owner or operator shall not exceed 1.2 lb/MMBtu per hour heat input based on a 3-hour rolling average. [Regulation 6.07, section 4.1]

ii. The owner or operator shall comply with the SO_2 emission allowances specified in Acid Rain Permit No.176-97-AR (R5). (See Acid Rain Permit Attachment) [Regulation 6.47, section 3.2 referencing 40 CFR Part 73]

iii. At all time, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate boiler E3 including associated SO_2 control equipment (FGD) in a manner consistent with good air pollution control practice for minimizing emissions.[33] [Regulation 1.05, section 5]

iv. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement of sulfur dioxide in the flue gas.
[Regulation 6.02, section 6.1.2] [Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1)]

g. **TAC**

i. The owner or operator shall not allow TAC emissions from boiler E3 to exceed the TAC emission standards determined based upon the EA Demonstration provided to the District.[34] (See Comment 1)
[Regulation 5.21, section 4.2 and section 4.3]

TAC Name	CAS #	TAC Limits Determination	
		(lbs/yr)	Basis of Limits
Naphthalene	91-20-3	16.6	Controlled PTE
Formaldehyde	50-00-0	70.3	Controlled PTE
Hydrogen fluoride	7664-39-3	13,385	Controlled PTE
Arsenic compounds	7440-38-2	266	Controlled PTE
Cadmium compounds	7440-43-9	42.1	Controlled PTE
Chromium VI	7440-47-3	94.5	Controlled PTE
Chromium III	16065-83-1	216	Controlled PTE
Cobalt compounds	7440-48-4	56.2	Controlled PTE
Lead compounds	7439-92-1	332	Controlled PTE

[33] The SO2 emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for SO2.

[34] This table for TAC emission standards has been revised to exclude Category 3 and 4 TACs for existing sources and use “de minimis values”, instead of actual numbers for current de minimis levels, as emission standards.

TAC Name	CAS #	TAC Limits Determination (lbs/yr)	Basis of Limits
Manganese compounds	7439-96-5	424	Controlled PTE
Nickel compounds	7440-02-0	307	Controlled PTE
Sulfuric acid	7664-93-9	118,679	Controlled PTE
Benzene	71-43-2	De minimis values (See Comment 1)	De Minimis
Bromoform	75-25-2		De Minimis
Chloroform	67-66-3		De Minimis
Methylene chloride	75-09-2		De Minimis
Tetrachloroethylene (Perc)	127-18-4		De Minimis
Toluene	108-88-3		De Minimis
Xylene	1330-20-7		De Minimis
Hydrochloric acid	7647-01-0		De Minimis

ii. See Plantwide Requirements.

h. **Unit Operation**

i. The owner or operator shall shut down the existing emission unit U2 prior to the date when the new emission unit U23 becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days. (Regulation 2.05)

S2. Monitoring and Record Keeping
[Regulation 2.16, Section 4.1.9.1 and 4.1.9.2]

The owner or operator shall maintain the following records for a minimum of five years and make the records readily available to the District upon request.

a. **BART** [40 CFR 52, Subpart S]

i. The owner or operator shall maintain daily records of any periods of time where the process was operating and both PJFF baghouse and ESP were not operating or a declaration that the PJFF baghouse and/or ESP were operated at all times that day when the process was operating.

b. **HAP** [40 CFR 63 Subpart UUUUU]

i. The owner or operator shall comply with monitoring and record keeping requirements in 40 CFR 63 Subpart UUUUU. (See Attachment A)

ii. The owner or operator shall establish a site-specific minimum activated carbon injection rate for PAC injection system according to Attachment B.[35] The owner or operator shall monitor and record the activated carbon injection rate during each operating day.

iii. The owner or operator shall monitor and record all Hg emission data from the Hg sorbent traps, which is used as the indicator of normal operation of the Hg control measures.

iv. The owner or operator shall monitor and record the pH of the reactant material in the FGD and any other parameters verified as having a direct effect on Hg emissions during each operating day, which is (are) used as the indicator(s) of normal operation of Hg control measures.[36]

v. The owner or operator shall maintain records of which Hg control devices/measure was being used during each operating day.

c. **NO_x**

i. The owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan. (See NO_x RACT Attachment) [Regulation 6.42, section 4.3]

ii. The owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

iii. The owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR (R5). These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F. (See Appendix A to NOx RACT Plan) [Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76]

iv. The owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75, section 75.57(d). For each NO_x emission rate (in lb/mmBtu) measured by a NO_x-diluent monitoring system, or, if applicable, for each NO_x concentration (in ppm) measured by a NO_x concentration monitoring system used to calculate NO_x mass emissions under 40 CFR 75.71(a)(2), record the following data as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

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[35] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore, the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

[36] LG&E has established normal pH range per monitoring records during consecutive 180 days. On 10/20/2016, LG&E reported that the normal pH range for this unit is 4.8 – 6.4.

(1) Component-system identification code, as provided in 40 CFR 75.53 (including identification code for the moisture monitoring system, if applicable); [40 CFR 75.57(d)(1)]

(2) Date and hour; [40 CFR 75.57(d)(2)]

(3) Hourly average NOx concentration (ppm, rounded to the nearest tenth) and hourly average NOx concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); [40 CFR 75.57(d)(3)]

(4) Hourly average diluent gas concentration (for NOx -diluent monitoring systems, only, in units of percent O_2 or percent CO_2, rounded to the nearest tenth); [40 CFR 75.57(d)(4)]

(5) If applicable, the hourly average moisture content of the stack gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O_2, rounded to the nearest tenth);
[40 CFR 75.57(d)(5)]

(6) Hourly average NOx emission rate (for NOx -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth); [40 CFR 75.57(d)(6)]

(7) Hourly average NOx emission rate (for NOx -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d). The requirement to report hourly NOx emission rates to the nearest thousandth shall not affect NOx compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu;
[40 CFR 75.57(d)(7)]

(8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NOx -diluent or NOx concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to 40 CFR 75.32; [40 CFR 75.57(d)(8)]

(9) Method of determination for hourly average NOx emission rate or NOx concentration and (if applicable) for the hourly average moisture percentage, using Codes 1–55 in Table 4a of 40 CFR 75.57; and [40 CFR 75.57(d)(9)]

(10) Identification codes for emissions formulas used to derive hourly average NOx emission rate and total NOx mass emissions, as provided in 40 CFR 75.53, and (if applicable) the F-factor used to convert NOx concentrations into emission rates.
[40 CFR 75.57(d)(10)]

v. A CEMS for measuring either oxygen (O_2) or carbon dioxide (CO_2) in the flue gases shall be installed, calibrated, maintained, and operated by the owner or operator. [Regulation 6.02, section 6.1.3] (NO_x RACT Plan)

vi. The owner or operator shall monitor the NO_x emissions, the NO_x allowances, as specified in the applicable NO_x cap and trade program(s) in effect.

vii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	**Span value for NO_X**
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

viii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards.

(1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(a) E = pollutant emissions, ng/J (lb/MMBtu).

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2,723 × 10 $^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532 × 10 $^{-17}$ scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.637 × 10 $^{-7}$ dscm/J (9,820 dscf/MMBtu) and F_c= 0.486 × 10 $^{-7}$ scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476 × 10 $^{-7}$ dscm/J (9,220 dscf/MMBtu) and F_c= 0.384 × 10 $^{-7}$ scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347 × 10 $^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279 × 10 $^{-7}$ scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322 × 10 $^{-7}$ scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338 × 10 $^{-7}$ scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589 × 10 $^{-7}$ dscm/J (9,640 dscf/MMBtu) and F_c= 0.500 × 10 $^{-7}$ scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492 × 10 $^{-7}$ dscm/J (9,280 dscf/MMBtu) and F_c= 0.494 × 10 $^{-7}$ scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.659 × 10 $^{-7}$ dscm/J (9,900 dscf/MMBtu) and F_c= 0.516 × 10 $^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu).

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0\times10^{-5}(\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321\times10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:
X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);
F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and
n = Number of fuels being burned in combination.

d. **Opacity**

i. If certified COMS is used to demonstrate compliance with opacity standards, the owner or operator shall record on an hourly basis all opacity from COMS.[37]

ii. If VE/Method 9 is used to demonstrate compliance with opacity standards, in order for the owner or operator to use its VE observations to satisfy the opacity monitoring requirement, the following conditions must be met:[16] (EPA Letter, 2007)

(1) On a weekly basis, the owner or operator shall attempt to perform VE observations in accordance with procedures in EPA Method 9.

(2) On the weeks when it is possible to collect unit-specific VE data, at least one hour of Method 9 data shall be collected for each unit.

(3) Records of the Method 9 readings shall be submitted with the quarterly excess emission reports for PM emissions.

iii. The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day.

iv. <u>For coal silos (E4):</u>

(1) The owner or operator shall, weekly, conduct a one-minute visible emissions survey, during normal operation, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation.

(2) At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

(3) The owner or operator shall, monthly, maintain records of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible

[37] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 2. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

e. **PM**

i. The company shall follow one of the two options below to demonstrate compliance with PM standards:

(1) Option 1: the owner or operator shall install, maintain, calibrate, and operate a PM CEMS for each steam generating unit. [38, 39] [Regulation 2.16, section 4.1.1] [40 CFR 64]

(a) The use of PM CEMS as the measurement technique must be appropriate for the stack conditions.

(b) The PM CEMS must be installed, operated and maintained in accordance with the manufacturer's recommendations.

(c) The PM CEMS must be certified in accordance with Performance Specification 11, Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources, found in 40 CFR 60 Appendix B.

(d) A quality assurance/quality control program must be implemented in accordance with procedures in 40 CFR 60 Appendix F, Procedure 2 (Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources).

(e) Compliance with the particulate matter emission limit will be based upon 3-hour rolling average periods during source operation.

(f) Quarterly excess emission reports must be submitted, and PM excess emissions shall be reported based upon 3-hour rolling averages during source operation.

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[38] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 2. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

[39] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 3/20/2020, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

(2) Option 2: the owner or operator shall conduct an annual EPA Reference Method 5 performance test following the testing requirements in Attachment B.

ii. If certified PM CEMS (Option 1) is used to demonstrate compliance with PM standards, the owner or operator shall record on an hourly basis all PM emission data, in lb/MMBtu, from PM CEMS.[40] [40 CFR 64]

iii. If annual PM testing (Option 2) is used to demonstrate compliance with PM standards, the owner or operator shall use PM CEMS as a performance indicator of continuous normal operation of the PM control devices and do the following:[40] [40 CFR 64]

(1) The owner or operator shall monitor and record all PM emission data from PM CEMS, which is used as the indicator of normal operation of the PM control devices.

(2) The owner or operator shall maintain daily records of any periods of time where the process was operating and the PM control devices were not operating or a declaration that the PM control devices operated at all times that day when the process was operating.

(3) If there is any time that the PM control devices are bypassed or not in operation when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

(a) Date;

(b) Start time and stop time;

(c) Identification of the control devices and process equipment;

(d) PM emissions during the bypass in lb/hr;

(e) Summary of the cause or reason for each bypass event;

(f) Corrective action taken to minimize the extent or duration of the bypass event; and

(g) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

f. **SO_2**

i. The owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

[40] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 3/20/2020, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

ii. The owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.57(c): [40 CFR 64]

(1) For SO_2 concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: [40 CFR 75.57(c)(1)]

(a) Component-system identification code, as provided in 40 CFR 75.53; [40 CFR 75.57(c)(1)(i)]

(b) Date and hour; [40 CFR 75.57(c)(1)(ii)]

(c) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth); [40 CFR 75.57(c)(1)(iii)]

(d) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d); [40 CFR 75.57(c)(1)(iv)]

(e) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to 40 CFR 75.32; and [40 CFR 75.57(c)(1)(v)]

(f) Method of determination for hourly average SO_2 concentration using Codes 1–55 in Table 4a of 40 CFR 75.57. [40 CFR 75.57(c)(1)(vi)]

(2) For flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: [40 CFR 75.57(c)(2)]

(a) Component-system identification code, as provided in 40 CFR 75.53; [40 CFR 75.57(c)(2)(i)]

(b) Date and hour; [40 CFR 75.57(c)(2)(ii)]

(c) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand); [40 CFR 75.57(c)(2)(iii)]

(d) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); [40 CFR 75.57(c)(2)(iv)]

(e) Percent monitor data availability (recorded to the nearest tenth of a percent) for the flow monitor, calculated pursuant to 40 CFR 75.32; and [40 CFR 75.57(c)(2)(v)]

(f) Method of determination for hourly average flow rate using Codes 1–55 in Table 4a of 40 CFR 75.57. [40 CFR 75.57(c)(2)(vi)]

(3) For SO_2 mass emission rate during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: [40 CFR 75.57(c)(4)]

(a) Date and hour; [40 CFR 75.57(c)(4)(i)]

(b) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth); [40 CFR 75.57(c)(4)(ii)]

(c) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); and [40 CFR 75.57(c)(4)(iii)]

(d) Identification code for emissions formula used to derive hourly SO2 mass emission rate from SO2 concentration and flow and (if applicable) moisture data in paragraphs (c)(1), (c)(2), and (c)(3) of 40 CFR 75.57, as provided in 40 CFR 75.53. [40 CFR 75.57(c)(4)(iv)]

iii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	**Span value for NO_X**
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

iv. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards.

(1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(a) E = pollutant emissions, ng/J (lb/MMBtu).

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = $2{,}723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532×10^{-17} scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.637×10^{-7} dscm/J (9,820 dscf/MMBtu) and F_c= 0.486×10^{-7} scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476×10^{-7} dscm/J (9,220 dscf/MMBtu) and F_c= 0.384×10^{-7} scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347×10^{-7} dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279×10^{-7} scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589×10^{-7} dscm/J (9,640 dscf/MMBtu) and F_c= 0.500×10^{-7} scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492×10^{-7} dscm/J (9,280 dscf/MMBtu) and F_c= 0.494×10^{-7} scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17),

$F = 2.659 \times 10^{-7}$ dscm/J (9,900 dscf/MMBtu) and $F_c = 0.516 \times 10^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu).

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{6}\frac{[227.2\,(\%H) + 95.5\,(\%C) + 35.6\,(\%S) + 8.7\,(\%N) - 28.7\,(\%O)]}{GCV}$$

$$F_c = \frac{2.0\times10^{-5}\,(\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{6}\frac{[3.64\,(\%H) + 1.53\,(\%C) + 0.57\,(\%S) + 0.14\,(\%N) - 0.46\,(\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\,(\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321\times10^{3}\,(\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.)

(iii) For affected facilities which fire both fossil fuels and non-fossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

Where:
X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);
F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and
n = Number of fuels being burned in combination.

g. **TAC**

i. The owner or operator shall, monthly, calculate and record TAC emissions for this unit in order to demonstrate compliance with the TAC emission standards.

ii. See Plantwide Requirements.

S3. Reporting
[Regulation 2.16, Section 4.1.1]

The owner or operator shall report the following information, as required by General Condition G14:

a. **BART** [40 CFR 52, Subpart S]

i. The owner or operator shall report any periods of time where the process was operating and both PJFF baghouse and ESP were not operating.

b. **HAP** [40 CFR 63 Subpart UUUUU]

i. The owner or operator shall comply with reporting requirements in 40 CFR 63 Subpart UUUUU. (See Attachment A)

ii. Report normal pH range of reactant material in the FGD and normal range of any other parameters verified as having a direct effect on Hg emission within 30 days of establishing the normal range.

iii. The owner or operator shall identify all periods of the activated carbon injection rate are less than the minimum injection rate, or the pH of the reactant material in the FGD are out of normal range, or anytime other verified parameters are outside of their normal range, and any corrective action taken for each exceedance.

c. **NO_x**

i. The owner or operator shall identify all periods of exceeding a NO_x emission standard during a quarterly reporting period. The quarterly compliance report shall include the following:

(1) Emission Unit ID number and emission point ID number;

(2) Identification of all periods during which a deviation occurred;

(3) A description, including the magnitude, of the deviation;

(4) If known, the cause of the deviation;

(5) A description of all corrective actions taken to abate the deviation; and

(6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the pollutant/source category in question. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. The required report shall include:
[Regulation 6.02, section 16.1]

(1) For gaseous measurements, the summary shall consist of hourly averages in the units of the applicable standard. The hourly averages shall not appear in the written summary, but shall be made available electronically.[41] [Regulation 6.02, section 16.3]

(2) The data and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustment shall be reported. Proof of continuous monitoring system performance whenever system repairs or adjustments have been made is required. [Regulation 6.02, section 16.4]

(3) When no excess emissions have occurred and the continuous monitoring systems have been inoperative, repaired, or adjusted, such information shall be included in the report.
[Regulation 6.02, section 16.5]

(4) Owners or operators of affected facilities shall maintain a file of all information reported in the quarterly summaries, and all other data collected either by the continuous monitoring system or as necessary to convert monitoring data to the units of the applicable standard for a minimum of two years from the date of collection of such data or

[41] The hourly averages are only required to be made available in electronic summary, not in written summary.

submission of such summaries.
[Regulation 6.02, section 16.6]

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R5), specified in 40 CFR 75 Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator[42], and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)

iv. The owner or operator shall comply with the reporting requirements for the Title IV NO_x Budget Emission Limitation, 0.40 lb/MMBtu, as specified in 40 CFR Part 76.

v. Excess emissions for affected facilities using a CEMS for measuring NO_X are defined as: [Regulation 2.16, section 4.1.9.3]

(1) Any annual average period during which the average emissions (arithmetic average of all one-hour period during the 12 month period) of NOx as measured by a CEMS exceed the applicable standard.

(2) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_X as measured by a CEMS exceed the applicable standard.

d. **Opacity**

i. The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

(1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests and documented reason;

(2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed and documented reason;

(3) The number, date, and time of each VE Survey where visible emissions were observed and the results of the Method 9 test performed;

(4) Identification of all periods of exceeding an opacity standard;

(5) Description of any corrective action taken for each exceedance of the opacity standard; or

[42] In this permit, Administrator means the District.

(6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R5), specified in 40 CFR 75 Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)
[Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76]

iii. For coal silos (E4):

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

(1) Emission Unit ID number, Stack ID number, and/or Emission point ID number;

(2) The beginning and ending date of the reporting period;

(3) The date, time and results of each exceedance of the opacity standard;

(4) Description of any corrective action taken for each exceedance.

e. **PM**

i. The owner or operator shall identify all periods of exceeding a PM emission standard during a quarterly reporting period. The report shall include the following:

(1) Emission Unit ID number and emission point ID number;

(2) The date and duration (including the start and stop time) during which a deviation occurred;

(3) The magnitude of excess emissions;

(4) Description of the deviation and summary information on the cause or reason for excess emissions;

(5) Corrective action taken to minimize the extent and duration of each excess emissions event;

(6) Measures implemented to prevent reoccurrence of the situation that resulted in excess PM emissions; or

(7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known.

f. **SO_2**

i. The owner or operator shall identify all periods of exceeding a SO_2 emission standard during a quarterly reporting period. The report shall include the following:

(1) Emission Unit ID number and emission point ID number;

(2) Identification of all periods during which a deviation occurred;

(3) A description, including the magnitude, of the deviation;

(4) If known, the cause of the deviation;

(5) A description of all corrective actions taken to abate the deviation; and

(6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known.

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R5), specified in 40 CFR 75 Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - Reporting Requirements. (See Attachment E)

iv. Excess emissions for affected facilities using a CEMS for measuring SO_2 are defined as: [Regulation 2.16, section 4.1.9.3]

(1) Any 3-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard; or

(2) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard.

g. **TAC**

i. The owner or operator shall identify all periods of exceeding a TAC emission standard during a quarterly reporting period. The report shall include the following:

(1) Emission Unit ID number and emission point ID number;

(2) Identification of all periods during which a deviation occurred;

(3) A description, including the magnitude, of the deviation;

(4) If known, the cause of the deviation;

(5) A description of all corrective actions taken to abate the deviation; and

(6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. See Plantwide Requirements.

S4. Testing
[Regulation 2.16, section 4.3.1]

a. **Control efficiency determination**

i. The owner or operator shall conduct performance test for the new EGU control device C27 and C28, according to the testing requirements in Attachment B, C and H. [43, 44] [Regulation 2.16, section 4.1.9.1]

ii. The owner or operator shall conduct a subsequent performance test to determine the control efficiency for sulfuric acid (H_2SO_4) by June 3, 2025, according to the testing requirements in Attachment B and C.[45] [Regulation 2.16, section 4.1.9.1]

U2 Comments

1. Boiler (E3) has TAC emission standards since its EA Demonstration was based on controlled PTE. If the controlled PTE for the TAC is less than de minimis level, use De Minimis as limit. If the controlled PTE for the TAC is greater than de minimis level, modeling results were used to calculate risk value to compare to the EA Goals. In this case, controlled PTE is used as limit. TAC emissions for the coal silos (E4) are de minimis according to Regulation 5.21, section 2.1. The TAC emission limits determined by de minimis values shall be updated each time when the District revises the BAC/de minimis values for these TACs. The current de minimis values per TAC list revised on 11/9/2017 are as the following:

TAC Name	CAS #	De minimis values (lb/hr)	(lb/Ave Period)	(lb/yr)
Benzene	71-43-2	0.24		216

[43] Per an EPA rule change ("Restructuring of the Stationary Source Audit Program." Federal Register 75:176 (September 13, 2010) pp 55636-55657), if an audit sample is required by the test method, sources became responsible for obtaining the audit samples directly from accredited audit sample suppliers, not the regulatory agencies.

[44] This unit was modified under construction permit 34595-12-C. According to permit 34595-12-C, the source is required to conduct stack tests to obtain actual emission factors and control efficiencies. Control efficiencies stack test for C26 and C27 were conducted on June 4-8, 2015

[45] Compliance with STAR Program for sulfuric acid was based on controlled sulfuric acid emissions. The source shall use the updated control efficiency to calculate actual sulfuric acid emissions.

TAC Name	CAS #	De minimis values		
		(lb/hr)	(lb/Ave Period)	(lb/yr)
Bromoform	75-25-2	0.49		437
Chloroform	67-66-3	0.023		20.64
Methylene chloride	75-09-2	54		48,000
Tetrachloroethylene (Perc)	127-18-4	2.08		1,848
Toluene	108-88-3	2700	2,400,000 lb/yr	
Xylene	1330-20-7	54	48,000 lb/yr	
Hydrochloric acid	7647-01-0	10.8	9,600 lb/yr	

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Emission Unit U23: EGU Unit 5 Gas Turbine with HRSG (664 MW Net)

Applicable Regulations [7]

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
2.05	Prevention of Significant Deterioration of Air Quality	1, 2
2.16	Title V Operating Permits	1 through 6
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
40 CFR 60 Subpart KKKK	Standards of Performance for Stationary Combustion Turbines	40 CFR 60.4300 through 60.4420, Table 1 (Subpart KKKK)
40 CFR 60 Subpart TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units	40 CFR 60.5508 through 60.5580, Tables 1 through 3 (Subpart TTTT)
40 CFR 63 Subpart YYYY	National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines	40 CFR 63.6080 through 63.6175, Tables 1 through 7 (Subpart YYYY)
40 CFR 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1-9, 11, 13, 14, 15, Appendix A and B
40 CFR 77	Excess Emissions	77.1- 6
40 CFR 78	Appeals Procedures for Acid Rain Program	78.1-20

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
7.02	Federal New Source Performance Standards Incorporated by Reference	1 through 5
STAR regulations are 5.00, 5.01, 5.20, 5.21, 5.22, and 5.23		

Equipment

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
E49a	Natural gas-fired combustion turbine (H Class or similar), Manufacturer: TBD, Model: TBD, equipped with a heat recovery steam generator (HRSG) with natural gas-fired duct burners (DB): Emissions from Cold; Warm, and Hot Startups, and Shutdown events will be released from same emissions point.	2027	STAR, 5.02, 5.14, 6.42, 6.47, 7.02, 40 CFR 72-73, 75-78, 40 CFR 60 Subpart KKKK & TTTT 40 CFR 63 Subpart YYYY	C43 & C44	S49

Control Devices

Control ID	Description	Control Efficiency	Performance Indicator
C43	Oxidation Catalyst, make TBD, model TBD, used to control CO, VOC, and OHAP emissions for GT and DB	50-90%	Pressure drop range 0.5" to 1.0" water column and Catalytic bed inlet gas temperature
C44	SCR controls with aqueous ammonia injection, make TBD, model TBD, used to control NO_X emissions for GT and DB	75-91%	Ammonia solutions injection rate and NO_X emissions from CEM

U23 Specific Conditions

S1. Standards
[Regulation 2.16, Section 4.1.1]

a. **NOx**

i. The new combustion turbine firing natural gas, which has a combustion turbine heat input at peak load (HHV) greater than 850 MMBtu/hr, shall meet 15 parts per million (ppm) at 15% oxygen (O_2); or 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour (lb/MWh)), based upon a 30-unit operating day rolling average (per 40 CFR 60.4350(h)). (See NOx RACT Plan) [40 CFR 60.4320 & 40 CFR 60, Subpart KKKK, Table 1] [Regulation 6.42, section 4.3]

ii. For turbines operating at less than 75 percent peak load that have a combustion turbine heat input at peak load (HHV) greater than 30 MW output, shall meet 96 ppm at 15% O_2; or 590 ng/J of useful output (4.7 lb/MWh), based upon a 30-unit operating day rolling average (per 40 CFR 60.4350(h)). (See NOx RACT Plan) [40 CFR 60.4320 & 40 CFR 60, Subpart KKKK, Table 1] [Regulation 6.42, section 4.3]

b. **SO_2**

The owner or operator shall comply with the emissions standards in 40 CFR 60.4330(a)(1) or (2). [40 CFR 60.4330(a)]

i. The owner or operator shall not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. [40 CFR 60.4330(a)(2)]

c. **General Requirement of NSPS KKKK**

i. The owner or operator must operate and maintain the stationary combustion turbine, air pollution control equipment, 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. [40 CFR 60.4333(a)]

d. **CO_2**

i. The CO_2 emissions of each affected turbine on a 12-month rolling average basis shall not exceed one of the following limits, consistent with 40 CFR 60.5520(b), (c), and (d), as applicable: [40 CFR 60.5520(a) and 60.5525(a) and Table 2 of NSPS TTTT]

(1) 1,000 lb/MWh of gross energy output; or

(2) 1,030 lb/MWh of net energy output.

ii. Stationary combustion turbines subject to a heat input-based standard in Table 2 of NSPS TTTT that are only permitted to burn one or more uniform fuels, as described in 40 CFR 60.5520(d)(1), are only subject to the monitoring requirements in 40 CFR 60.5520(d)(1). All other stationary combustion turbines subject to a heat input based standard in Table 2 are subject to the requirements in 40 CFR 60.5520(d)(2). [40 CFR 60.5520(d)]

(1) Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (i.e., uniform fuels) that result in a consistent emission rate of 160 lb CO_2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

e. **General Requirement of NSPS TTTT**

i. Combustion turbines qualifying under 40 CFR §60.5520(d)(1) are not subject to any requirements in 40 CFR 60.5525(a) through (c) other than the requirement to maintain fuel purchase records for permitted fuel(s). [40 CFR §60.5525]

f. **HAP**

i. U23/E49a, which is a lean premix gas-fired stationary combustion turbine as defined in 40 CFR §63.6175, must limit the concentration of formaldehyde to 91 ppbvd or less at 15-percent O_2, except during turbine startup. [40 CFR §63.6100 and Table 1, Item 1, of NESHAP YYYY]

ii. The period of time for turbine startup is subject to the limits specified in the definition of startup in §63.6175, where startup begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 1 hour, whichever is less. For combined cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 3 hours, whichever is less. Turbines in combined cycle configurations that are operating as simple cycle turbines must meet the startup requirements for simple cycle turbines while operating as simple cycle turbines. [40 CFR §63.6100 and Table 1, Item 1, of 40 CFR 63 Subpart YYYY]

iii. For U23/49a that is required to comply with the emission limitation for formaldehyde and uses an oxidation catalyst, the permittee must maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The permittee is not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature. [40 CFR §§63.6100 and 63.6140 and Table 2, Item 1, of NESHAP YYYY]

g. **General Requirement of NESHAP YYYY**

i. Duct burners and waste heat recovery units are considered steam generating units and are not covered under NESHAP YYYY. In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners in operation. [40 CFR §63.6092]

ii. The permittee must comply with the emissions limitations and operating limitations of NESHAP YYYY upon startup of the affected source. [40 CFR §63.6095(a)(4)]

iii. At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR §63.6105(c)]

h. **VOC**

i. The owner or operator shall implement good combustion and operating practices and comply with the applicable operating limitations of 40 CFR 63, Subpart YYYY (See VOC RACT Attachment) [Regulation 6.42, Sections 4.1 and 4.2]

i. **TAC**

i. See Plantwide Requirements.[123]

S2. Monitoring and Record Keeping
[Regulation 2.16, sections 4.1.9.1 and 4.1.9.2]

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **NOx**

i. As an alternative to performing annual performance tests, the owner or operator may install, maintain, calibrate and operate one of the following continuous monitoring systems: (See Attachment B - NOx RACT Plan) [40 CFR 60.4340(b)]

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345. [40 CFR 60.4340(b)(1)]

(2) Pursuant to §60.4335(b),

(a) the owner or operator may install, certify, maintain, and operate a CEMS consisting of a NOx monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NOx emission rate in ppm or lb/MMBtu; and [40 CFR 60.4335(b)(1)]

(b) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and [40 CFR 60.4335(b)(2)]

(c) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and [40 CFR 60.4335(b)(3)]

(d) For combined heat and power units complying with the

[123] According to Regulation 5.21, section 2.7, TAC emissions from the natural gas-fired turbine are de minimis.

output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h). [40 CFR 60.4335(b)(4)]

ii. See NO_X RACT Plan [Regulation 6.42, Section 4.3]

iii. Pursuant to 40 CFR 60.4340(b)(1), the NO_X CEMS shall meet the following requirements: [40 CFR 60.4345]

(1) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis. [40 CFR 60.4345(a)]

(2) As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour. [40 CFR 60.4345(b)]

(3) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart. [40 CFR 60.4345(c)]

(4) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions. [40 CFR 60.4345(d)]

(5) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring

equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter. [40 CFR 60.4345(e)]

iv. The owner or operator will identify excess emissions using the following guidelines: [40 CFR 60.4350]

(1) All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h). [40 CFR 60.4350(a)]

(2) For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations. [40 CFR 60.4350(b)]

(3) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed. [40 CFR 60.4350(c)]

(4) If the owner or operator have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c). [40 CFR 60.4350(d)]

(5) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. [40 CFR 60.4350(e)]

(6) Calculate the hourly average NO_X emission rates, in units of the emission standards under 40 CFR 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output-based standard: [40 CFR 60.4350(f)]

(a) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations: [40 CFR 60.4350(f)(2)]

$$E = \frac{(NO_X)_h * (HI)_h}{P} \quad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/hr, measured using the fuel flowmeters, e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW

$$P = (PE)_t + (PE)_c + Ps + Po \quad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system (MW)

$(PE)_t$ = electrical or mechanical energy output of the CT (MW)

$(PE)_c$ = electrical or mechanical output of the steam turbine (MW)

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the system, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/hr,

H = enthalpy of steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and

3.413×10^6 = conversion from Btu/hr to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(7) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from 40 CFR 60.4350(f) of this section to assess excess emissions on a 30-unit operating day rolling average basis, as described in 40 CFR 60.4380(b)(1). [40 CFR 60.4350(h)]

b. **SO_2**

i. The owner or operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas. The owner or operator must use one of the following sources of information to make the required demonstration: [40 CFR 60.4365]

(1) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO2/MMBtu) heat input for continental areas; or meet 40 CFR 60.4365(b) [40 CFR 60.4365(a)]

c. **CO_2**

i. Pursuant to 40 CFR §60.5535, combustion turbines qualifying under §60.5520(d)(1) are not subject to any requirements for monitoring and recordkeeping other than the requirement to maintain fuel purchase records for permitted fuel(s). [40 CFR 60.5535]

d. **HAP**

i. See Plantwide Requirements.

ii. Since U23/49a is required to comply with the formaldehyde emission limitation and an oxidation catalyst emission control device is used, the permittee must monitor on a continuous basis the catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of NESHAP YYYY. [40 CFR 63.6125(a)]

(1) For a stationary combustion turbine that is required to comply with the emissions limitation for formaldehyde and is using an oxidation system, the permitting must maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The permittee is not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature. [40 CFR 63.6125(a) and Table 2, Item 1, of NESHAP YYYY]

(2) Initial compliance is demonstrated if the average formaldehyde concentration meets the emission limitations specified in Table 1 of NESHAP YYYY. [40 CFR 63.6110, 63.6125, 63.6130, and Table 4 NESHAP YYYY]

(3) Continuous compliance with the operating limit is demonstrated by continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer. [40 CFR 63.6135, 63.6140(a), and Table 5 of NESHAP YYYY]

(4) The permittee must report each instance in which they did not meet each emission limitation or operating limitation. The permittee must also report each instance in which they did not meet the requirements in Table 7 of NESHAP YYYY that apply to U23/49a. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6150. [40 CFR 63.6140(b)]

iii. Since the temperature monitoring system is a continuous monitoring system (CMS), the permittee must develop and implement a CMS quality control program that includes written procedures for CMS according to §63.8(d)(1) through (2). The permittee must keep these written procedures on record for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, the owner or operator shall keep previous (i.e., superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. The program of corrective action should be included in the plan required under §63.8(d)(2). [40 CFR 63.6125(e)]

iv. Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), the permittee must conduct all parametric monitoring at all times the stationary combustion turbine is operating. [40 CFR 63.6135(a)]

v. Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. The permittee must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine. [40 CFR 63.6135(b)]

vi. The owner or operator must keep the records as described in 40 CFR 63.6155(a)(1) through (7). [40 CFR 63.6155(a)]

vii. The owner or operator must keep the records required in Table 5 of 40 CFR 63 Subpart YYYY to show continuous compliance with each operating limitation that applies. [40 CFR 63.6155(c)]

viii. Any records required to be maintained by this part that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation. [40 CFR 63.6155(d)]

e. **VOC**

i. The owner or operator shall comply with the applicable monitoring and recordkeeping requirements of 40 CFR 63, Subpart YYYY (See VOC RACT Attachment) [Regulation 6.42, Sections 4.1 and 4.2].

f. **TAC**

i. See Plantwide Requirements.

S3. Reporting
[Regulation 2.16, section 4.1.9.3]

The owner or operator shall report the following information, as required by General Condition G14:

a. **General requirements for NSPS KKKK**

i. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, the owner or operator must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. [40 CFR 60.4375(a)]

ii. Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form to the District semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 60th day following the end of each six-month reporting period. Written reports of excess emissions shall include the following information:
[40 CFR 60.4395 and 40 CFR 60.7(c)]

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period. [40 CFR 60.7(c)(1)]

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted. [40 CFR 60.7(c)(2)]

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. [40 CFR 60.7(c)(3)]

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report. [40 CFR 60.7(c)(4)]

iii. All reports required under 40 CFR 60.7(c) shall be postmarked by the 60th day following the end of each reporting period. [40 CFR 60.4395]

b. **NOx**

i. For turbines using continuous emission monitoring, periods of excess emissions and monitor downtime that must be reported are defined as follows: [40 CFR 60.4380(b)]

(1) An excess emissions is any unit operating period in which the 30-day rolling average NO_X emission rate exceeds the applicable emission limit in 40 CFR 60.4320. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30-unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours. [40 CFR 60.4380(b)(1)]

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the owner or operator will use this information for compliance purposes. [40 CFR 60.4380(b)(2)]

ii. The owner or operator shall comply with the quarterly reporting requirements as specified in the NO_X RACT Plan. (See Attachment D)

c. **CO_2**

i. For the affected turbines, the Permittee shall comply with the notification notifications in §60.7(a)(1) and (3) and the reporting requirements of §60.19, as applicable. [40 CFR 60, Subpart A, 40 CFR 60.5550(a) and Table 3 of NSPS TTTT]

d. **HAP**

i. The permittee must submit all of the notifications in §§ 63.7(b) Notification of Performance Testing and (c) Quality Assurance/Test Plan, 63.8(e) CMS Performance Evaluation (Except for §63.8(e)(5)(ii), which applies to COMS), 63.8(f)(4) Alternative Monitoring, and 63.9(b) Initial Notifications and (h) Notice of Compliance Status that apply to the GT by the dates specified. [40 CFR 60, Subpart A, 40 CFR 63.6145(a) and Table 7 of NESHAP YYYY]

ii. If the permittee is required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with §63.6090(b), the notification must include the information in §63.9(b)(2)(i) through (v) and a statement that the new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine). [40 CFR 63.6145(d)]

iii. If the permittee is required to conduct an initial performance test, the permittee must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in §63.7(b)(1). [40 CFR 63.6145(e)]

iv. If the permittee is required to comply with the emission limitation for formaldehyde, the permittee must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, the permittee must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test. [40 CFR 63.6145(f)]

v. **Compliance report.** The owner or operator of a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of NESHAP YYYY. The semiannual compliance report must contain the information described in §63.6150(a)(1) through (5). The semiannual compliance report, including the excess emissions and monitoring system performance reports of §63.10(e)(3), must be submitted by the dates specified in §63.6150(b)(1) through (5), unless the Administrator has approved a different schedule. After September 8, 2020, or once the reporting template has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 180 days, whichever date is later, the permittee must submit all subsequent reports to the EPA following the procedure specified in 40 CFR 63.6150(g). [40 CFR 63.6150(a)]

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) After September 8, 2020, report each deviation in the semiannual compliance report. Report the information specified in 40 CFR 63.6150(a)(5)(i) through (iv). [40 CFR 60.4380(b)(5)]

(a) Report the number of deviations. For each instance, report the start date, start time, duration, and cause of each deviation, and the corrective action taken.

(b) For each deviation, the report must include a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, a description of the method used to estimate the emissions.

(c) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks), as applicable, and the corrective action taken.

(d) Report the total operating time of the affected source during the reporting period.

vi. The first semiannual compliance report must cover the period beginning on the compliance date specified in §63.6095 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date specified in §63.6095. [40 CFR 63.6150(b)(1)]

vii. The first semiannual compliance report must be postmarked or delivered no later than August 29 or March 1, whichever date follows the end of the first calendar half after the compliance date that is specified in § 63.6095

[40 CFR 63.6150(b)(2) and (5)]

viii. Each subsequent semiannual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. [40 CFR 63.6150(b)(3)]

ix. Each subsequent semiannual compliance report must be postmarked or delivered no later than August 29 or March 1, whichever date is the first date following the end of the semiannual reporting period. [40 CFR 63.6150(b)(4) and (5)]

x. For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section. [40 CFR 63.6150(b)(5)]

xi. ***Performance test report.*** After September 8, 2020, within 60 days after the date of completing each performance test required by this subpart, the owner or operator must submit the results of the performance test (as specified in 40 CFR 63.6145(f)) following the procedures specified in 40 CFR 63.6150(f)(1) through (3). [40 CFR 63.6150(f)]

(1) ***Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.*** Submit the results of the performance test to the EPA via the CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. [40 CFR 63.6150(f)(1)]

(2) ***Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.*** The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI. [40 CFR 63.6150(f)(2)]

(3) ***Confidential business information (CBI).*** If the permittee claims some of the information submitted under 40 CFR

63.6150(f)(1) is CBI, the permittee must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in 40 CFR 63.6150(f)(1). [40 CFR 63.6150(f)(3)]

e. **TAC**

i. See Plantwide Requirements.[124]

S4. Testing
[Regulation 2.16, section 4.1.9.1]

a. **General testing requirements**

i. See Plantwide Requirements.

b. **NO_X**

i. If the owner or operator elects to install and certify a NO_X-diluent CEMS under 40 CFR 60.4345, then the initial performance test required under 40 CFR 60.8 may be performed in the following alternative manner: [40 CFR 60.4405]

(1) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.
[40 CFR 60.4405(a)]

(2) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit. [40 CFR 60.4405(b)]

[124] According to Regulation 5.21, section 2.7, TAC emissions from the natural gas-fired turbine are de minimis.

(3) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under 40 CFR 60.4320 and to provide the required reference method data for the RATA of the CEMS described under 40 CFR 60.4335. [40 CFR 60.4405(c)]

(4) Compliance with the applicable emission limit in 40 CFR 60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit. [40 CFR 60.4405(d)]

ii. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. The owner or operator may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. The owner or operator must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes. [40 CFR 60.4400(b)]

(1) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), the permittee must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test. [40 CFR 60.4400(b)(2)]

(2) Compliance with the applicable emission limit in 40 CFR 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in 40 CFR 60.4320. [40 CFR 60.4400(b)(4)]

(3) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit. [40 CFR 60.4400(b)(5)]

(4) The ambient temperature must be greater than 0°F during the performance test. [40 CFR 60.4400(b)(6)]

c. **HAP**

i. The permittee must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of NESHAP YYYY that apply within 180 calendar days after the compliance date that is specified for the stationary combustion turbine in §63.6095 and according to the provisions in §63.7(a)(2). [40 CFR 63.6110(a)]

ii. An owner or operator is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in 40 CFR 63.6110(b)(1) through (b)(5). [40 CFR 63.6110(b)]

(1) The test must have been conducted using the same methods specified in NESHAP YYYY, and these methods must have been followed correctly. [40 CFR 63.6110(b)(1)]

(2) The test must not be older than 2 years. [40 CFR 63.6110(b)(2)]

(3) The test must be reviewed and accepted by the Administrator. [40 CFR 63.6110(b)(3)]

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes. [40 CFR 63.6110(b)(4)]

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load. [40 CFR 63.6110(b)(5)]

iii. Subsequent performance tests must be performed on an annual basis as specified in Table 3 of NESHAP YYYY. [40 CFR 63.6115]

iv. The owner or operator must conduct each performance test in Table 3 of NESHAP YYYY that applies. [40 CFR 63.6120(a)]

(1) Each performance test must be conducted according to the requirements in Table 3 of NESHAP YYYY. Before September 8, 2020, each performance test must be conducted according to the requirements of the General Provisions at § 63.7(e)(1). [40 CFR 63.6120(b)]

(2) Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent. After September 8, 2020, performance tests shall be conducted under such conditions based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. The owner or operator may not conduct performance tests during periods of malfunction. The owner or operator must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent normal operation. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests. [40 CFR 63.6120(c)]

(3) You must conduct three separate test runs for each performance test, and each test run must last at least 1 hour. [40 CFR 63.6120(d)]

Emission Unit U24: 99.9 MMBtu/hr Natural Gas-Fired Auxiliary Steam Boiler

Applicable Regulations

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
2.05	Prevention of Significant Deterioration of Air Quality	1 through 2
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1 through 5
7.06	Standards of Performance for New Indirect Heat Exchangers	1, 2, 3, 4.1.2, 4.2, 5.1.2, 6
40 CFR 60 Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	40 CFR 60.40c through 60.48c
40 CFR 63 Subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	40 CFR 63.7480 through 63.7575

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1 through 2
5.01	General Provisions	1 through 2
5.02	Adoption and Incorporation by Reference of National Emission Standards for Hazardous Air Pollutants	1, 2, 4, 5
5.14	Hazardous Air Pollutants and Source Categories	1, 2, 3.1.1
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 7
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.23	Categories of Toxic Air Contaminants	1 through 6
7.02	Adoption of Federal New Source Performance Standards	1 through 5
STAR regulations are 5.00, 5.01, 5.20, 5.21, 5.22, and 5.23		

Equipment

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
E50	NG Fired Auxiliary Boiler (99.9 MMBtu/hr) with LNB & FGR	Planned 2027	STAR, 5.02, 5.14, 6.42, 7.06, 40CFR60-Dc, 40CFR63-DDDDD	N/A	S50

Control Devices

There is no control device associated with this unit.

U24 Specific Conditions

S1. Standards
[Regulation 2.16, Section 4.1.1]

a. **HAP** [40 CFR 63 Subpart DDDDD]

i. Because the Auxiliary Boiler (U24) is a unit designed to burn gas 1 fuels, it is not subject to the emission limits in 40 CFR 63, Subpart DDDDD Tables 1 and 2 or 11 through 13, or the operating limits in 40 CFR 63, Subpart DDDDD Table 4. [40 CFR 63.7500(e)]

ii. The owner or operator shall complete an annual or 5-year tune-up as applicable as specified in 40 CFR 63.7540. [40 CFR 63.7500(a)(1) referencing Items 1 and 3 of 40 CFR 63, Subpart DDDDD, Table 3]

iii. At all times, the permittee shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.7500(a)(3)]

iv. The permittee shall demonstrate initial compliance with the applicable work practice standards in 40 CFR 63, Subpart DDDDD, Table 3 within the applicable annual, biennial, or 5-year schedule as specified in 40 CFR 63.7515(d) following the initial compliance date specified in 40 CFR 63.7495(a). Thereafter, the permittee is required to complete the annual, biennial or 5-year tune-up as specified in 40 CFR 63.7515(d). [40 CFR 63.7510(g)]

v. If the permittee is required to meet an applicable tune-up work practice standard, the permittee shall conduct an annual, biennial, or 5-year performance tune-up according to 40 CFR 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in 40 CFR 63.7540(a)(10) shall be no more than 13 months after the previous tune-up. Each biennial tune-up specified in 40 CFR 63.7540(a)(11) shall be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in 40 CFR 63.7540(a)(12) shall be conducted no more than 61 months after the previous tune-up. If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup. [40 CFR 63.7515(d) and 63.7540(a)(13)]

vi. The permittee shall conduct an annual tune-up of the boiler or process heater as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. This frequency does not apply to units with continuous oxygen trim systems that maintain an optimum air to fuel ratio. [40 CFR 63.7540(a)(10)]

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment; [40 CFR 63.7540(a)(10)(i)]

(2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available; [40 CFR 63.7540(a)(10)(ii)]

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection. [40 CFR 63.7540(a)(10)(iii)]

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the unit is subject. [40 CFR 63.7540(a)(10)(iv)]

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and [40 CFR 63.7540(a)(10)(v)]

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in 40 CFR 63.7540(a)(10)(vi)(A) through (C), [40 CFR 63.7540(a)(10)(vi)]

(a) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater; [40 CFR 63.7540(a)(10)(vi)(A)]

(b) A description of any corrective actions taken as part of the tune-up; and [40 CFR 63.7540(a)(10)(vi)(B)]

(c) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may establish the fuel used by each unit. [40 CFR 63.7540(a)(10)(vi)(C)]

vii. If the boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, the owner or operator must conduct a tune-up of the boiler or process heater every 5 years as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. The owner or operator may delay the burner inspection specified in 40 CFR 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown, but the owner or operator must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, the owner or operator shall set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up. [40 CFR 63.7450(a)(12)]

viii. During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii). [401 KAR 59:015, Section 7 and 401 KAR 59:015, Section 7(2)(a)]

b. **NO_X**

i. See NO_X RACT Plan [Regulation 6.42, Section 4.3]

c. **Opacity**

i. The owner or operator shall not allow visible emissions to equal or exceed 20% opacity from emission point E50, except: [Regulation 7.08, section 3.1.2][125]

(1) A maximum of 40% opacity shall be permissible for not more than two consecutive minutes in any 60 consecutive minutes; [Regulation 7.06, Section 4.2.1]

(2) A maximum of 40% opacity shall be permissible for not more than six consecutive minutes in any 60 consecutive minutes during

[125] The District has determined that using a natural gas fired boiler will inherently meet the 20% opacity standard.

cleaning the fire box or blowing soot; [Regulation 7.06, Section 4.2.2]

(3) For emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. [Regulation 7.06, Section 4.2.3]

d. **PM**

i. The owner or operator shall not allow PM emissions to exceed 0.10 lb/MMBtu from emission point E50. [Regulation 7.06, Section 4.1.2]

e. **SO_2**

i. The owner or operator shall not allow SO_2 emissions to exceed 0.8 lb/MMBtu from emission point E50. [Regulation 7.06, Section 5.1.2]

f. **VOC**

i. The owner or operator shall implement good combustion and operating practices (See VOC RACT Attachment). [Regulation 6.42, Sections 4.1 and 4.2]

g. **TAC**

i. See Plantwide Requirements.

S2. Monitoring and Record Keeping
[Regulation 2.16, sections 4.1.9.1 and 4.1.9.2]

a. **40 CFR 60 Subpart Dc General Requirements**

i. The owner or operator shall monitor and maintain records of natural gas usage (MMscf) for U24 on a monthly basis. [40 CFR 60.48c(g)(2)]

ii. All records required under 40 CFR 60.48c shall be maintained by the owner or operator for a period of two years following the date of such record. [40 CFR 60.48c(i)]

b. **HAP** [40 CFR 63 Subpart DDDDD]

i. The owner or operator shall keep a copy of each notification and report submitted to comply with 40 CFR 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report submitted, according to the requirements of 40 CFR 63.10(b)(2)(xiv). [40 CFR 63.7555(a) and 63.7555(a)(1)]

ii. If the owner or operator operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies. [40 CFR 63.7555(h)]

iii. Records of notifications and reports submitted to comply with 40 CFR 63 Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). [40 CFR 63.7560(a)]

iv. As specified in 40 CFR 63.10(b)(1), the owner or operator shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 CFR 63.7560(b)]

v. The owner or operator shall keep each record on site, or they shall be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years. [40 CFR 63.7560(c)]

c. **NO_X**

i. See NO_X RACT Plan [Regulation 6.42, Section 4.3]

d. **TAC**

i. See Plantwide Requirements

S3. Reporting
[Regulation 2.16, section 4.1.9.3]

The owner or operator shall report the following information, as required by General Condition G14:

a. **40 CFR 60 Subpart Dc General Requirements**

i. The permittee shall submit notification of the date of construction or reconstruction and actual startup, as provided by 40 CFR 60.7. This notification shall include: [40 CFR 60.48c(a)]

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility. [40 CFR 60.48c(a)(1)]

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under 40 CFR 60.42c, or 60.43c. [40 CFR 60.48c(a)(2)]

(3) The annual capacity factor at which the permittee anticipates operating the affected facility based on all fuel fired and based on each individual fuel fired. [40 CFR 60.48c(a)(3)]

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of 40 CFR 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator. [40 CFR 60.48c(a)(4)]

b. **HAP** [40 CFR 63 Subpart DDDDD]

i. The permittee must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD. [40 CFR 63.7495(d)]

ii. The permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 7545(e). [40 CFR 63.7530(f)]

iii. The permittee shall report each instance in which an emission limit and operating limit in 40 CFR 63, Subpart DDDDD, Table 3, as applicable, was not met. These instances are deviations from the emission limits or operating limits, respectively, in 40 CFR 63, Subpart DDDDD. These deviations shall be reported according to the requirements in 40 CFR 63.7550. [40 CFR 63.7540(b)]

iv. The permittee shall submit to the Administrator all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified. [40 CFR 63.7545(a)]

v. As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. [40 CFR 63.7545(c)]

vi. The permittee shall submit the Notification of Compliance Status and shall contain the information specified in 40 CFR 63.7545(e)(1) and (8) and shall be submitted within 60 days of the compliance date specified at 40 CFR 63.7495(b). [40 CFR 63.7545 (e)]

(1) A description of the affected units including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with 40 CFR 63, Subpart DDDDD, description of the fuel burned, including whether the fuel was a secondary material determined by the permittee or the EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel was a secondary material processed from discarded non-hazardous secondary material within the meaning of 40 CFR 241.3, and justification for the selection of fuel burned during the compliance demonstration. [40 CFR 63.7545(e)(1)]

(2) In addition to information required in 40 CFR 63.9(h)(2), the notification of compliance status must include the following certifications of compliance, as applicable, and signed by a responsible official: [40 CFR 63.7545(e)(8)]

(a) "This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in 40 CFR 63.7540(a)(10)(i) through (vi)." [40 CFR 63.7545(e)(8)(i)]

vii. If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5). [40 CFR 63.7545(f)]

(1) Company name and address. [40 CFR 63.7545(f)(1)]

(2) Identification of the affected unit. [40 CFR 63.7545(f)(2)]

(3) Reason the permittee is unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began. [40 CFR 63.7545(f)(3)]

(4) Type of alternative fuel that the permittee intends to use. [40 CFR 63.7545(f)(4)]

(5) Dates when the alternative fuel use is expected to begin and end. [40 CFR 63.7545(f)(5)]

viii. The permittee shall submit each report in 40 CFR 63, Subpart DDDDD, Table 9 that applies. [40 CFR 63.7550(a)]

ix. The permittee may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in 40 CFR 63.7550(b)(1) through (4): [40 CFR 63.7550(b)]

(1) If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in 40 CFR 63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for the source in 40 CFR 63.7495. [40 CFR 63.7550(b)(1)]

(2) The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than March 1. [40 CFR 63.7550(b)(2) and (5)]

(3) Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5- year periods from January 1 to December 31. [40 CFR 63.7550(b)(3)]

(4) Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than March 1. [40 CFR 63.7550(b)(4) and (5)]

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4). [40 CFR 63.7550(b)(5)]

x. The permittee shall submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii): [40 CFR 63.7550(c)(1)]

(1) Company and Facility name and address. [40 CFR 63.7550(c)(5)(i)]

(2) Process unit information, emission limitations, and operating parameter limitations. [40 CFR 63.7550(c)(5)(ii)]

(3) Date of report and beginning and ending dates of the reporting period. [40 CFR 63.7550(c)(5)(iii)]

(4) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to 40 CFR 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annual, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown [40 CFR 63.7550(c)(5)(xiv)]

(5) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. [40 CFR 63.7550(c)(5)(xvii)]

xi. The permittee shall submit the reports according to the procedures specified in 40 CFR 63.7550(h)(1) through (3). [40 CFR 63.7550(h)]

(1) The permittee must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. [40 CFR 63.7550(h)(3)]

c. **NO_X**

i. See NO_X RACT Plan [Regulation 6.42, Section 4.3]

S4. Testing
[Regulation 2.16, section 4.1.9.3]

a. **General Testing Requirements**

i. The owner or operator shall permit the District or Administrator of the EPA to conduct performance tests at any reasonable time shall cause the affected facility to be operated for purposes of those tests under the conditions as the District or the Administrator of the EPA may specify based on representative performance of the affected facility, and shall make available to the District those records as may be necessary to determine the performance. [Regulation 1.04, Section 2.8]

Emission Unit U26: 15 MMBtu/hr Natural Gas-Fired Fuel Gas Dewpoint Heater

Applicable Regulations

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
2.05	Prevention of Significant Deterioration of Air Quality	1 through 2
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1 through 5
7.06	Standards of Performance for New Indirect Heat Exchangers	1, 2, 3, 4.1.2, 4.2, 5.1.2, 6
40 CFR 60 Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	40 CFR 60.40c through 60.48c
40 CFR 63 Subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	40 CFR 63.7480 through 63.7575

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1 through 2
5.01	General Provisions	1 through 2
5.02	Adoption and Incorporation by Reference of National Emission Standards for Hazardous Air Pollutants	1, 2, 4, 5
5.14	Hazardous Air Pollutants and Source Categories	1, 2, 3.1.1
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 7
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.23	Categories of Toxic Air Contaminants	1 through 6
7.02	Adoption of Federal New Source Performance Standards	1 through 5
STAR regulations are 5.00, 5.01, 5.20, 5.21, 5.22, and 5.23		

Equipment

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
E52	NG Fired Fuel Gas Dewpoint Heater (15 MMBtu/hr)	Planned 2027	STAR, 5.02, 5.14, 6.42, 7.06, 40CFR60-Dc, 40CFR63-DDDDD	N/A	S52

Control Devices

There is no control device associated with this unit.

U26 Specific Conditions

S5. Standards
[Regulation 2.16, Section 4.1.1]

a. **HAP** [40 CFR 63 Subpart DDDDD]

i. Because the Fuel Gas (Dewpoint) Heater (U26) is a unit designed to burn gas 1 fuels, they are not subject to the emission limits in 40 CFR 63, Subpart DDDDD Tables 1 and 2 or 11 through 13, or the operating limits in 40 CFR 63, Subpart DDDDD Table 4. [40 CFR 63.7500(e)]

ii. The owner or operator shall complete an annual or 5-year tune-up as applicable as specified in 40 CFR 63.7540. [40 CFR 63.7500(a)(1) referencing Items 1 and 3 of 40 CFR 63, Subpart DDDDD, Table 3]

iii. At all times, the permittee shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.7500(a)(3)]

iv. The permittee shall demonstrate initial compliance with the applicable work practice standards in 40 CFR 63, Subpart DDDDD, Table 3 within the applicable annual, biennial, or 5-year schedule as specified in 40 CFR 63.7515(d) following the initial compliance date specified in 40 CFR 63.7495(a). Thereafter, the permittee is required to complete the annual, biennial or 5-year tune-up as specified in 40 CFR 63.7515(d). [40 CFR 63.7510(g)]

v. If the permittee is required to meet an applicable tune-up work practice standard, the permittee shall conduct an annual, biennial, or 5-year performance tune-up according to 40 CFR 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in 40 CFR 63.7540(a)(10) shall be no more than 13 months after the previous tune-up. Each biennial tune-up specified in 40 CFR 63.7540(a)(11) shall be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in 40 CFR 63.7540(a)(12) shall be conducted no more than 61 months after the previous tune-up. If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup. [40 CFR 63.7515(d) and 63.7540(a)(13)]

vi. The permittee shall conduct an annual tune-up of the boiler or process heater as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. This frequency does not apply to units with continuous oxygen trim systems that maintain an optimum air to fuel ratio. [40 CFR 63.7540(a)(10)]

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment; [40 CFR 63.7540(a)(10)(i)]

(2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available; [40 CFR 63.7540(a)(10)(ii)]

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection. [40 CFR 63.7540(a)(10)(iii)]

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the unit is subject. [40 CFR 63.7540(a)(10)(iv)]

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and [40 CFR 63.7540(a)(10)(v)]

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in 40 CFR 63.7540(a)(10)(vi)(A) through (C), [40 CFR 63.7540(a)(10)(vi)]

(a) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater; [40 CFR 63.7540(a)(10)(vi)(A)]

(b) A description of any corrective actions taken as part of the tune-up; and [40 CFR 63.7540(a)(10)(vi)(B)]

(c) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may establish the fuel used by each unit. [40 CFR 63.7540(a)(10)(vi)(C)]

vii. If the boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, the owner or operator must conduct a tune-up of the boiler or process heater every 5 years as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. The owner or operator may delay the burner inspection specified in 40 CFR 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown, but the owner or operator must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, the owner or operator shall set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up. [40 CFR 63.7450(a)(12)]

viii. During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii). [401 KAR 59:015, Section 7 and 401 KAR 59:015, Section 7(2)(a)]

b. **NO_X**

i. See NO_X RACT Plan [Regulation 6.42, Section 4.3]

c. **Opacity**

i. The owner or operator shall not allow visible emissions to equal or exceed 20% opacity from emission point E52, except:[126] [Regulation 7.08, section 3.1.2]

(1) A maximum of 40% opacity shall be permissible for not more than two consecutive minutes in any 60 consecutive minutes; [Regulation 7.06, Section 4.2.1]

(2) A maximum of 40% opacity shall be permissible for not more than six consecutive minutes in any 60 consecutive minutes during

[126] The District has determined that using a natural gas fired heater will inherently meet the 20% opacity standard.

cleaning the fire box or blowing soot; [Regulation 7.06, Section 4.2.2]

(3) For emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. [Regulation 7.06, Section 4.2.3]

d. **PM**

i. The owner or operator shall not allow PM emissions to exceed 0.10 lb/MMBtu from emission point E52. [Regulation 7.06, Section 4.1.2]

e. **SO_2**

i. The owner or operator shall not allow SO_2 emissions to exceed 0.8 lb/MMBtu from emission point E52. [Regulation 7.06, Section 5.1.2]

f. **VOC**

i. The owner or operator shall implement good combustion and operating practices (See VOC RACT Attachment). [Regulation 6.42, Sections 4.1 and 4.2]

g. **TAC**

i. See Plantwide Requirements.

S6. Monitoring and Record Keeping
[Regulation 2.16, sections 4.1.9.1 and 4.1.9.2]

a. **40 CFR 60 Subpart Dc General Requirements**

i. The owner or operator shall monitor and maintain records of natural gas usage (MMscf) for U26 on a monthly basis. [40 CFR 60.48c(g)(2)]

ii. All records required under 40 CFR 60.48c shall be maintained by the owner or operator for a period of two years following the date of such record. [40 CFR 60.48c(i)]

b. **HAP** [40 CFR 63 Subpart DDDDD]

i. The owner or operator shall keep a copy of each notification and report submitted to comply with 40 CFR 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report submitted, according to the requirements of 40 CFR 63.10(b)(2)(xiv). [40 CFR 63.7555(a) and 63.7555(a)(1)]

ii. If the owner or operator operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies. [40 CFR 63.7555(h)]

iii. Records of notifications and reports submitted to comply with 40 CFR 63 Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). [40 CFR 63.7560(a)]

iv. As specified in 40 CFR 63.10(b)(1), the owner or operator shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 CFR 63.7560(b)]

v. The owner or operator shall keep each record on site, or they shall be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years. [40 CFR 63.7560(c)]

c. **NO_X**

i. See NO_X RACT Plan [Regulation 6.42, Section 4.3]

d. **TAC**

i. See Plantwide Requirements

S7. Reporting
[Regulation 2.16, section 4.1.9.3]

The owner or operator shall report the following information, as required by General Condition G14:

a. **40 CFR 60 Subpart Dc General Requirements**

i. The permittee shall submit notification of the date of construction or reconstruction and actual startup, as provided by 40 CFR 60.7. This notification shall include: [40 CFR 60.48c(a)]

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility. [40 CFR 60.48c(a)(1)]

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under 40 CFR 60.42c, or 60.43c. [40 CFR 60.48c(a)(2)]

(3) The annual capacity factor at which the permittee anticipates operating the affected facility based on all fuel fired and based on each individual fuel fired. [40 CFR 60.48c(a)(3)]

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of 40 CFR 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator. [40 CFR 60.48c(a)(4)]

b. **HAP** [40 CFR 63 Subpart DDDDD]

i. The permittee must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD. [40 CFR 63.7495(d)]

ii. The permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 7545(e). [40 CFR 63.7530(f)]

iii. The permittee shall report each instance in which an emission limit and operating limit in 40 CFR 63, Subpart DDDDD, Table 3, as applicable, was not met. These instances are deviations from the emission limits or operating limits, respectively, in 40 CFR 63, Subpart DDDDD. These deviations shall be reported according to the requirements in 40 CFR 63.7550. [40 CFR 63.7540(b)]

iv. The permittee shall submit to the Administrator all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified. [40 CFR 63.7545(a)]

v. As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. [40 CFR 63.7545(c)]

vi. The permittee shall submit the Notification of Compliance Status and shall contain the information specified in 40 CFR 63.7545(e)(1) and (8) and shall be submitted within 60 days of the compliance date specified at 40 CFR 63.7495(b). [40 CFR 63.7545 (e)]

(1) A description of the affected units including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with 40 CFR 63, Subpart DDDDD, description of the fuel burned, including whether the fuel was a secondary material determined by the permittee or the EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel was a secondary material processed from discarded non-hazardous secondary material within the meaning of 40 CFR 241.3, and justification for the selection of fuel burned during the compliance demonstration. [40 CFR 63.7545(e)(1)]

(2) In addition to information required in 40 CFR 63.9(h)(2), the notification of compliance status must include the following certifications of compliance, as applicable, and signed by a responsible official: [40 CFR 63.7545(e)(8)]

(a) "This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in 40 CFR 63.7540(a)(10)(i) through (vi)." [40 CFR 63.7545(e)(8)(i)]

vii. If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5). [40 CFR 63.7545(f)]

(1) Company name and address. [40 CFR 63.7545(f)(1)]

(2) Identification of the affected unit. [40 CFR 63.7545(f)(2)]

(3) Reason the permittee is unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began. [40 CFR 63.7545(f)(3)]

(4) Type of alternative fuel that the permittee intends to use. [40 CFR 63.7545(f)(4)]

(5) Dates when the alternative fuel use is expected to begin and end. [40 CFR 63.7545(f)(5)]

viii. The permittee shall submit each report in 40 CFR 63, Subpart DDDDD, Table 9 that applies. [40 CFR 63.7550(a)]

ix. The permittee may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in 40 CFR 63.7550(b)(1) through (4): [40 CFR 63.7550(b)]

(1) If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in 40 CFR 63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for the source in 40 CFR 63.7495. [40 CFR 63.7550(b)(1)]

(2) The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31. [40 CFR 63.7550(b)(2)]

(3) Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5- year periods from January 1 to December 31. [40 CFR 63.7550(b)(3)]

(4) Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31. [40 CFR 63.7550(b)(4)]

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4). [40 CFR 63.7550(b)(5)]

x. The permittee shall submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii): [40 CFR 63.7550(c)(1)]

(1) Company and Facility name and address. [40 CFR 63.7550(c)(5)(i)]

(2) Process unit information, emission limitations, and operating parameter limitations. [40 CFR 63.7550(c)(5)(ii)]

(3) Date of report and beginning and ending dates of the reporting period. [40 CFR 63.7550(c)(5)(iii)]

(4) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to 40 CFR 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annual, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown [40 CFR 63.7550(c)(5)(xiv)]

(5) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. [40 CFR 63.7550(c)(5)(xvii)]

xi. The permittee shall submit the reports according to the procedures specified in 40 CFR 63.7550(h)(1) through (3). [40 CFR 63.7550(h)]

(1) The permittee must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. [40 CFR 63.7550(h)(3)]

c. **NO_X**

i. See NO_X RACT Plan [Regulation 6.42, Section 4.3]

S8. Testing

[Regulation 2.16, section 4.1.9.3]

a. **General Testing Requirements**

i. The owner or operator shall permit the District or Administrator of the EPA to conduct performance tests at any reasonable time shall cause the affected facility to be operated for purposes of those tests under the conditions as the District or the Administrator of the EPA may specify based on representative performance of the affected facility, and shall make available to the District those records as may be necessary to determine the performance. [Regulation 1.04, Section 2.8]

Emission Unit U25: 2 MW Diesel-Fired Emergency Generator

Applicable Regulations

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
40 CFR 63 Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	63.6603, 6604, 6605, 6625, 6640, 6645, 6655
40 CFR 60 Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	60.4200 - 4219

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
STAR regulations are 5.00, 5.01, 5.20, 5.21, 5.22, and 5.23		

Equipment

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
E51	One 2 MW diesel generator, make Caterpillar, model C18, or equivalent, rated at 2,925 BHP, model year post-2006 (Tier 2)	Planned 2027	40 CFR 63 Subpart ZZZZ, 40 CFR 60 Subpart IIII, STAR[127]	N/A	S51

Control Devices

There is no control device associated with this unit.

[127] This equipment is subject to STAR since it has TAC emissions.

U25 Specific Conditions

S1. Standards
[Regulation 2.16, section 4.1.1]

a. General Requirements for NSPS IIII

i. The owner or operator of 2007 model year or later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in 40 CFR 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE. [40 CFR 60.4205(b)]

Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in 40 CFR 60.4202(a)(1) through (2).
[40 CFR 60.4202(a) refers to 40 CFR 1039, Appendix I, and 40 CFR 1039.105]

unit: g/KW-hr	NO_X + NMHC	CO	PM
Emission Standards (Table 2 to 40 CFR 1039 Appendix I	6.4	3.5	0.20
Smoke emission standard (40 CFR 1039.105(b)	1) 20% during acceleration mode 2) 15% during lugging mode 3) 50% during peaks in acceleration or lugging mode		

ii. The owner or operator must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engine. [40 CFR 60.4206]

iii. Beginning October 1, 2010, the owner or operator of a stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that uses diesel fuel shall use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted: [40 CFR 60.4207(b)]

(1) Sulfur content: 15 parts per million (ppm) maximum for NR diesel fuel. [40 CFR 1090.305(b)]

(2) A minimum cetane index of 40; or [40 CFR 1090.305(c)(1)]

(3) A maximum aromatic content of 35 volume percent. [40 CFR 1090.305(c)(2)]

iv. The owner or operator that must comply with the emission standards specified in 40 CFR 60 Subpart IIII shall do all of the following: [40 CFR 60.4211(a)]

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; [40 CFR 60.4211(a)(1)]

(2) Change only those emission-related settings that are permitted by the manufacturer; [40 CFR 60.4211(a)(2)]

v. The owner or operator shall purchase an engine certified to the emission standards in 40 CFR 60.4205(b), as applicable for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications. [40 CFR 60.4211(c)]

vi. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in 60 CFR 60.4211(f)(1) through (3), is prohibited. If the owner or operator does not operate the engine according to the requirements in 60 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines. [40 CFR 60.4211(f)]

(1) There is no time limit on the use of emergency stationary ICE in emergency situations. [40 CFR 60.4211(f)(1)]

(2) The owner or operator may operate the emergency stationary ICE for the purpose specified in 40 CFR 60.4211(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 60.4211(f)(2). [40 CFR 60.4211(f)(2)]

(a) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. [40 CFR 60.4211(f)(2)(i)]

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in 40 CFR 60.4211(f)(2). Except as provided in 40 CFR 60.4211(f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity. [40 CFR 60.4211(f)(3)]

(a) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met: [40 CFR 60.4211(f)(3)(i)]

(i) The engine is dispatched by the local balancing authority or local transmission and distribution system operator; [40 CFR 60.4211(f)(3)(i)(A)]

(ii) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region. [40 CFR 60.4211(f)(3)(i)(B)]

(iii) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines. [40 CFR 60.4211(f)(3)(i)(C)]

(iv) The power is provided only to the facility itself or to support the local transmission and distribution system. [40 CFR 60.4211(f)(3)(i)(D)]

(v) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator. [40 CFR 60.4211(f)(3)(i)(E)]

b. **HAP**

i. The equipment listed in this emission unit is subject to 40 CFR 63 Subpart ZZZZ, however, there are no applicable HAP standards in this regulation.[128]

c. **TAC**

i. See Plantwide Requirements.[129]

S2. Monitoring and Record Keeping

[Regulation 2.16, sections 4.1.9.1 and 4.1.9.2]

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **Unit Operation**

i. The owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines shall install a non-resettable hour meter prior to startup of the engine. [40 CFR 60.4209(a)]

ii. The owner or operator is not required to submit an initial notification. Starting with the model years in Table 5 to 40 CFR 60 Subpart IIII, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator shall keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time. [40 CFR 60.4214(b)]

[128] According to 40 CFR 63.6590(c), E51 must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines. No further requirements apply for E51 under 40 CFR 63 other than the initial notification requirements in 40 CFR 63.6645(f).

[129] TAC emissions from this equipment are de minimis.

b. **HAP**

i. There are no compliance monitoring or record keeping requirements for HAP.

c. **TAC**

i. See Plantwide Requirements.

S3. Reporting
[Regulation 2.16, section 4.1.9.3]

The owner or operator shall report the following information, as required by General Condition G14:

a. **Unit Operation**

i. The owner or operator is not required to submit an initial notification under 40 CFR Subpart IIII. [40 CFR 60.4214(b)]

b. **HAP**

i. If the owner or operator is required to submit an Initial Notification but is otherwise not affected by the requirements of this subpart, the notification should include the information in 40 CFR 63.9(b)(2)(i) through (v), and a statement that the stationary RICE has no additional requirements and explain the basis of the exclusion. [40 CFR 63.6645(f)]

c. **TAC**

i. See Plantwide Requirements.

Permit Shield

The owner or operator is hereby granted a permit shield that shall apply as long as the owner or operator demonstrates ongoing compliance with all conditions of this permit. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements of the regulations cited in this permit as of the date of issuance, pursuant to Regulation 2.16, section 4.6.1.

Off-Permit Documents

The source has the following off-permit documents associated with this Title V permit:

1) Fugitive Dust Control Plan.

Alternative Operating Scenario

The company requested no alternative operating scenario in its Title V application.

Insignificant Activities

Equipment	Qty.	PTE (ton/yr)	Regulation Basis
Fuel or Lubricating oils storage tanks with vapor pressure <10mm Hg @ 20 deg C (See unit IA5)	17	0.005 VOC	Regulation 1.02, Appendix A, 3.9.2
1,000 gallon storage tank for #1 fuel oil with annual turnover < 2X the capacity (See unit IA5)	1	0.001 VOC	Regulation 1.02, Appendix A, 3.25
Minor natural gas combustion sources <10 MMBtu/hr (direct heat exchangers)	24	0.79 NOx	Regulation 2.16, section 1.23
Emergency relief vents for boiler steam supply	24	0	Regulation 1.02, Appendix A, 3.10
Lab exhaust systems	3	0.001 VOC	Regulation 1.02, Appendix A, 3.11
Portable kerosene storage tanks with capacity less than 500 gallons (See unit IA5)	1	3.5e-5 VOC	Regulation 1.02, Appendix A, 3.23
Ash pond with wet storage	1	0	Regulation 2.16, section 1.23
Cooling Towers for Unit 2 and Unit 3 (See unit IA5)	2	3.35 PM_{10}	Regulation 2.16, section 1.23
Cooling Tower for Unit 23 (See unit IA5)	1	1.03 tpy PM	Regulation 2.16, section 1.23
Stack piles (coal, limestone, gypsum piles)	3	1.66 PM_{10}	Regulation 2.16, section 1.23
Turbine oil reservoir vapor extractor	4	0	Regulation 2.16, section 1.23
Hydrogen seal oil tank vent	4	0	Regulation 2.16, section 1.23
Gypsum handling equipment (See unit IA5)	1	4.69 PM_{10}	Regulation 2.16, section 1.23

Equipment	Qty.	PTE (ton/yr)	Regulation Basis
Portable gypsum dewatering systems (See unit IA5)	2	1.27 PM_{10}	Regulation 2.16, section 1.23
Gasoline storage tank, 3,000 gallons (previous U10, see unit IA1)	1	1.87 VOC	Regulation 2.16, section 1.23
Non-halogenated cold solvent parts washers with secondary reservoir (previous U11, see unit IA2)	8	0.33 VOC	Regulation 2.16, section 1.23
Emergency generators, 800 HP each (previous U13, see unit IA3)	2	4.93 NOx	Regulation 2.16, section 1.23
Fire pumps, 157 HP, 183 HP (See unit IA4)	2	1.42 NOx	Regulation 2.16, section 1.23
Fire pump, 400 HP (See unit IA4)	1	0.575 NOx	Regulation 2.16, section 1.23
Emergency vent for U1 and U2 boilers	1	0.7 NOx	Regulation 2.16, section 1.23
Bottom/flyash silos (See unit IA5)	2	2.34 PM_{10}	Regulation 2.16, section 1.23
Ash pug mill mixers (See unit IA5)	4	4.7 PM_{10}	Regulation 2.16, section 1.23
Process water system (See unit IA5)	1	1.69 PM_{10}	Regulation 2.16, section 1.23
Emergency generator, natural gas fired, 105 HP (See unit IA3)	1	0.75 CO	Regulation 2.16, section 1.23
HVAC Heaters (Total Heat Input <10 MMBtu/hr, see unit IA5)	1	4.14 tpy NO_X	Regulation 2.16, section 1.23
Lube Oil System Demister Vents (see unit IA5)	1	0.66 tpy VOC	Regulation 2.16, section 1.23
Diesel Storage Tanks for NGCC Units (see unit IA5)	1	1.1E-3 tpy VOC	Regulation 2.16, section 1.23

1. Insignificant activities identified in District Regulation 1.02, Appendix A, may be subject to size or production rate disclosure requirements pursuant to Regulation 2.16 section 3.5.4.1.4.
2. Insignificant activities identified in District Regulation 1.02, Appendix A shall comply with generally applicable requirements as required by Regulation 2.16 section 4.1.9.4.
3. The Insignificant Activities Table is correct as of the date the permit was proposed for review by U.S. EPA, Region 4.
4. Emissions from Insignificant Activities shall be reported in conjunction with the reporting of annual emissions of the facility as required by the District.
5. The owner or operator shall submit an updated list of insignificant activities that occurred during the preceding year pursuant to Regulation 2.16 section 4.3.5.3.6.
6. The owner or operator may elect to monitor actual throughputs for each of the insignificant activities and calculate actual annual emissions, or use Potential to Emit (PTE) to be reported on the annual emission inventory.
7. The District has determined pursuant to Regulation 2.16 section 4.1.9.4 that no monitoring, record keeping, or reporting requirements apply to the insignificant activities listed, except

for the equipment that has an applicable regulation and permitted under an insignificant activity (IA) unit.

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Emission Unit IA4: Fire Pump Engines [140]

Applicable Regulations

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
40 CFR 63 Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	63.6603, 6604, 6605, 6625, 6640, 6645, 6655
40 CFR 60 Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	60.4200 - 4219

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
STAR regulations are 5.00, 5.01, 5.20, 5.21, 5.22, and 5.23		

Equipment [141]

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
IE9	One (1) diesel fire pump engine, make Clarke, model JU4H-UFADY8, rated at 157 HP with	2014	40 CFR 63 Subpart ZZZZ,	N/A	Fugitive

[140] Per Regulation 5.21, section 2.3, emissions from insignificant activity are de minimis.
[141] Potential emissions for this permitted operation are greatest for nitrogen oxides (NOx). Based on AP-42 Emission Factors and 500 hours per year for an emergency generator, as defined by EPA, the potential NOx emissions for this permitted operation is less than 5 tons per year.

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
	a 187 gallon diesel fuel tank.[142,143] Model year 2013		40 CFR 60 Subpart IIII, STAR[144]		
IE10	One (1) diesel fire pump engine, make Clarke, model JU6H-UFADY58, rated at 183 HP with a 300 gallon diesel fuel tank.[142,143] Model year 2013	2014	40 CFR 63 Subpart ZZZZ, 40 CFR 60 Subpart IIII, STAR[144]	N/A	Fugitive
IE28	One (1) diesel fire pump engine, make Clarke, or similar, rated at 400 HP with a 440 gallon diesel fuel tank. Model year post-2009	Planned 2027	40 CFR 63 Subpart ZZZZ, 40 CFR 60 Subpart IIII, STAR	N/A	Fugitive

Control Devices

There is no control device associated with this unit.

[142] This operation is subject to 40 CFR 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, because it involves a stationary reciprocating internal combustion engine (RICE) located at a major source of HAP emissions. The proposed new stationary RICE meets the definition in 40 CFR 63.6675 of an emergency stationary RICE, which, per 40 CFR 63.6590(c), shall meet the requirements of 40 CFR 63 Subpart ZZZZ and 40 CFR 60 Subpart IIII.

[143] Fire pump engine is an emergency engine per 40 CFR 60 Subpart IIII, 60.4219, "Fire pump engine" means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection."

[144] This equipment is subject to STAR since it has TAC emissions. Per Regulation 5.21, section 2.3, emissions from insignificant activity are de minimis.

IA4 Specific Conditions

S1. Standards
[Regulation 2.16, section 4.1.1]

a. **Unit Operation**

i. The owner or operator that must comply with the emission standards specified in 40 CFR 60 Subpart IIII shall do all of the following:
[40 CFR 60.4211(a)]

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; [40 CFR 60.4211(a)(1)]

(2) Change only those emission-related settings that are permitted by the manufacturer; [40 CFR 60.4211(a)(2)]

ii. The owner or operator shall purchase an engine certified to the emission standards in 40 CFR 60.4205(c), as applicable for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications. [40 CFR 60.4211(c)]

iii. Engine manufacturers shall certify the fire pump stationary CI engines to the emission standards in table 4 to 40 CFR 60 Subpart IIII, for all pollutants, for the same model year and NFPA nameplate power.
[40 CFR 60.4202(d)]

Fire pump engines for this unit are subject to following emission standards in g/KW-hr (g/HP-hr): [Table 4 to 40 CFR 60 Subpart IIII]

Equipment Description	Model Year	NMHC+ NO_x	CO	PM
IE9: 157 HP fire pump	2013	4.0 (3.0)	N/A	0.30 (0.22)
IE10: 183 HP fire pump	2013	4.0 (3.0)	N/A	0.20 (0.15)
IE28: 400 HP fire pump	Post-2009	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)

iv. The owner or operator must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engine. [40 CFR 60.4206]

v. The owner or operator shall not combust in the engine a nonroad diesel fuel that contains more than 15 ppm of sulfur.
[40 CFR 60.4207(b)] [40 CFR 80.510(b)(1)(i)]

vi. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in 40 CFR 60.4211(f)(1) through (3), is prohibited. If the owner or operator does not operate the engine according to the requirements in 40 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.
[40 CFR 60.4211(f), 40 CFR 63.6640(f)]

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.
[40 CFR 60.4211(f)(1), 40 CFR 63.6640(f)(1)]

(2) The owner or operator may operate the emergency stationary ICE for any combination of the purposes specified in 40 CFR 60.4211(f)(2)(i) through (iii) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by this paragraph.
[40 CFR 60.4211(f)(2), 40 CFR 63.6640(f)(2)]

(a) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.
[40 CFR 60.4211(f)(2)(i), 40 CFR 63.6640(f)(2)(i)]

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing.
[40 CFR 60.4211(f)(3), 40 CFR 63.6640(f)(3)]

vii. At all times the owner or operator shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by this standard have been achieved.

Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

b. **HAP**

i. The equipment listed in this emission unit is subject to 40 CFR 63 Subpart ZZZZ, however, there are no HAP standards.

c. **TAC**

i. See Plantwide Requirements.[145]

S2. Monitoring and Record Keeping
[Regulation 2.16, sections 4.1.9.1 and 4.1.9.2]

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **Unit Operation**

i. The owner or operator is not required to submit an initial notification. The owner or operator shall keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.
[40 CFR 60.4214(b)]

ii. The owner or operator shall maintain records of the fuel MSDS sheets and receipts showing dates, amounts of fuel purchased, sulfur content of fuel purchased and supplier's name and address, to show compliance.

b. **HAP**

i. There are no compliance monitoring or record keeping requirements for HAP.

c. **TAC**

i. See Plantwide Requirements.

[145] TAC emissions from this equipment are de minimis.

S3. Reporting
[Regulation 2.16, section 4.1.9.3]

The owner or operator shall report the following information, as required by General Condition G14:

a. **Unit Operation**

i. There are no routine reporting requirements for this equipment.

b. **HAP**

i. There are no routine reporting requirements for this equipment.

c. **TAC**

i. See Plantwide Requirements.

Emission Unit IA5: Other Insignificant Activities

Applicable Regulations

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Affected Facilities	1, 2, 3, 4, 5, 6

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
STAR regulations are 5.00, 5.01, 5.20, 5.21, 5.22, and 5.23		

Equipment

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
IE11	Seventeen (17) lubricating oil tanks, capacity ranged from 400 to 20,000 gallons, each has a vapor pressure less than 1.0 mmHg (< 0.019 psi)	N/A	STAR[146]	N/A	Fugitive
IE12	One (1) 1,000 gallon storage tank for #1 fuel oil with annual turnover < 2X the capacity, vapor pressure less than 0.019 psi	N/A		N/A	Fugitive
IE13	One (1) portable kerosene storage tanks with capacity less than 500 gallons, vapor pressure less than 0.019 psi	N/A		N/A	Fugitive
IE14	Two (2) cooling towers for Unit 2 and Unit 3	N/A	7.08	N/A	Fugitive

[146] This equipment is subject to STAR since it has TAC emissions. Per Regulation 5.21, section 2.3, emissions from insignificant activity are de minimis.

Emission Point	Description	Install Date	Applicable Regulations	Control ID	Release ID
IE15	One (1) gypsum handling equipment, including two (2) stackers, one (1) overland conveyor, one (1) barge loading, one (1) truck loading, four (4) belt filters, two (2) conveyors, two (2) hoppers, and three (3) transfer towers	N/A	7.08	N/A	Fugitive
IE17	One (1) bottom/fly ash storage silo equipped with bin vent filters, make and model TBD, rated capacity 325 tph.[147]	N/A	7.08	C40	S30
IE18	One (1) bottom/fly ash storage silo equipped with bin vent filters, make and model TBD, rated capacity 325 tph.[147]	N/A	7.08	C41	S31
IE19	One (1) pub mill mixers, make and model TBD, rated capacity 200 tph [147]	N/A	7.08	N/A	Fugitive
IE20	One (1) pub mill mixers, make and model TBD, rated capacity 200 tph [147]	N/A	7.08	N/A	Fugitive
IE21	One (1) pub mill mixers, make and model TBD, rated capacity 200 tph [147]	N/A	7.08	N/A	Fugitive
IE22	One (1) pub mill mixers, make and model TBD, rated capacity 200 tph [147]	N/A	7.08	N/A	Fugitive
IE23	One (1) process water system (PWS),[148] including:				
	IE23-a: one (1) hydrated lime silos with bin vent filters, make and model TBD, rated capacity 10 tph;	NA	7.08	C42-a	S32-a
	IE23-b: one (1) hydrated lime silos with bin vent filters, make and model TBD, rated capacity 10 tph;			C42-b	S32-b
	IE23-c: one (1) PWS solid material storage pile;			N/A	Fugitive
	IE23-d: one (1) front-end loader used to load material to trucks, capacity 20 tph.			N/A	Fugitive
IE24	Cooling Tower for Unit 23	N/A	7.08	N/A	Fugitive
IE25	Lube Oil System with Demister Vents	N/A	STAR	N/A	Fugitive
IE26	Diesel Storage Tanks for NGCC Units	N/A	STAR	N/A	Fugitive
IE27	HVAC Heaters (Total Heat Input < 10 MMBtu/hr	N/A	STAR	N/A	Fugitive

[147] A construction application for this equipment was submitted on 3/24/2017. The District has determined this is an insignificant activity per PTE, therefore no construction permit is required.
[148] A construction application for this equipment was submitted on 3/2/2018. The District has determined this is an insignificant activity per PTE, therefore no construction permit is required.

Control Devices

Control ID	Description	Control Efficiency	Performance Indicator
C40	One (1) bin vent filter controlling ash storage silo	98%	N/A[149]
C41	One (1) bin vent filter controlling ash storage silo	98%	N/A[149]
C42-a	One (1) bin vent filter controlling PWS hydrated lime silos	98%	N/A[149]
C42-b	One (1) bin vent filter controlling PWS hydrated lime silos	98%	N/A[149]

[149] The bin vent filter equipped for each silo is considered as an integrated component of the silo. However, there are monitoring, record keeping and reporting requirements associated with any times that the filters are not in place and the process is operated. The District's pre-approved control efficiency for bin vent filters is 98%.

IA5 Specific Conditions

S1. Standards
[Regulation 2.16, section 4.1.1]

a. **Opacity**

For ash storage silos and pug mill mixers (IE14-IE22), PWS (IE23), and Unit 23 Cooling Tower (IE24): The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. [Regulation 6.09, section 3.1] [Regulation 7.08, section 3.1.1]

b. **PM**

i. For cooling towers (IE14 and IE24): The owner or operator shall not allow PM emissions to exceed 93.4 lb/hr for Unit 2 cooling tower and 98.2 lb/hr for Unit 3 cooling tower, and 86.8 lb/hr for Unit 23 cooling tower based on actual operating hours in a calendar day.[150] [Regulation 7.08, section 3.1.2]

ii. For gypsum handling equipment (IE15): The owner or operator shall not allow PM emissions from all the gypsum handling equipment combined to exceed 36.2 lb/hr based on actual operating hours in a calendar day.150 [Regulation 7.08, section 3.1.2]

iii. For ash storage silos (IE17 and IE18): The owner or operator shall not allow PM emissions from each silo to exceed 43.7 lb/hr based on actual operating hours in a calendar day.[150] [Regulation 7.08, section 3.1.2]

iv. For pug mill mixers (IE19, IE20, IE21, and IE22): The owner or operator shall not allow PM emissions from each pug mill mixer to exceed 40.41 lb/hr based on actual operating hours in a calendar day.[150]
[Regulation 7.08, section 3.1.2]

v. For hydrated lime silos (IE23-a and IE23-b): The owner or operator shall not allow PM emissions from each silo to exceed 14.97 lb/hr based on actual operating hours in a calendar day.[150]
[Regulation 7.08, section 3.1.2]

vi. For PWS solid material storage pile (IE23-c) and front-end loader (IE23-d): The owner or operator shall not allow PM emissions from each silo to exceed 23.00 lb/hr based on actual operating hours in a calendar day.[150]
[Regulation 7.08, section 3.1.2]

vii. For ash silos (IE17 and IE18) and lime silos (IE23-a and IE23-b): The owner or operator shall maintain the bin vent filters in place at all times the process equipment is in operation, including periods of startup, shutdown, and

[150] It has been demonstrated that the PM emissions from this equipment cannot exceed the lb/hr PM standards uncontrolled.

malfunction, in a manner consistent with good air pollution control practice to meet the standards. [Regulation 1.05, section 5]

c. **TAC**

For storage tanks (IE11, IE12, and IE13, and IE26), Lube Oil System Demister Vents (IE25), and HVAC Heaters (IE27):

i. See Plantwide Requirements.[151]

S2. Monitoring and Record Keeping
[Regulation 2.16, sections 4.1.9.1 and 4.1.9.2]

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **Opacity**

i. There are no monitoring and record keeping requirements for IE14, and IE15, and IE24.

ii. For ash storage silos and pug mill mixers (IE17-IE22), PWS (IE23):

(1) The owner or operator shall, monthly, conduct a one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

(2) At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If correction actions are taken then a follow-up visible emission survey shall be made. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, 24 hours of the initial observation.

b. **PM**

i. There are no monitoring and record keeping requirements for IE14, and IE15, and IE24.

ii. For ash storage silos and pug mill mixers (IE17-IE22), hydrated lime silos (IE23-a and IE23-b):

(1) The owner or operator shall, monthly, maintain records of the type and amount of material throughput for each piece of equipment.

[151] TAC emissions from this equipment are de minimis.

iii. For ash storage silos (IE17 and IE18), hydrated lime silos (IE23-a and IE23-b):

(1) The owner or operator shall, monthly, perform a visual inspection of the structural and mechanical integrity of the bin vent filters for signs of damage, air leakage, corrosion, or other equipment defects, and repair and/or replace defective components as needed. The owner or operator shall maintain monthly records of the results.

(2) The owner or operator shall maintain daily records of any periods of time where the process was operating and the bin vent filters were not in place or a declaration that the bin vent filters were in place at all times that day when the process was operating.

(3) If there is any time that the bin vent filters are not in place when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

(a) Date;

(b) Start time and stop time;

(c) Identification of the bin vent filters and process equipment;

(d) PM emissions during the bypass in lb/hr;

(e) Summary of the cause or reason for each bypass event;

(f) Corrective action taken to minimize the extent or duration of the bypass event; and

(g) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

c. **TAC**

i. For storage tanks (IE11, IE12, and IE13, and IE26), Lube Oil System Demister Vents (IE25), and HVAC Heaters (IE27): See Plantwide Requirements.

S3. Reporting
[Regulation 2.16, section 4.1.9.3]

The owner or operator shall report the following information, as required by General Condition G14:

a. **Opacity**

i. There are no reporting requirements for IE14, and IE15, and IE24.

ii. For ash storage silos and pug mill mixers (IE17-IE22), PWS (IE23): The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

(1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests;

(2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed;

(3) The date and time of each VE Survey where visible emissions were observed and the results of any Method 9 test performed;

(4) The date, time and results of follow-up VE survey;

(5) The date, time, and results of any Method 9 test performed;

(6) Identification of all periods of exceeding an opacity standard; and

(7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

b. **PM**

i. There are no reporting requirements for IE14, IE15, IE19, IE20, IE21, and IE22.

ii. For ash silos (IE17 and IE18) and lime silos (IE23-a and IE23-b): The owner or operator shall report the following information regarding PM By-Pass Activity in the quarterly compliance reports.

(1) Number of times the PM vent stream by-passes the bin vent filters and is vented to the atmosphere;

(2) Duration of each by-pass to the atmosphere;

(3) Calculated pound per hour PM emissions for each by-pass; or

(4) A negative declaration if no by-passes occurred.

c. **TAC**

i. For storage tanks (IE11, IE12, and IE13, and IE26), Lube Oil System Demister Vents (IE25), and HVAC Heaters (IE27): See Plantwide Requirements.

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Attachment D - NO_x RACT Plan - Amendment 1

1. The oxides of nitrogen (NO_x, expressed as NO_2) emission from each utility boiler shall not exceed the rate as specified below, based upon a rolling 30-day average:

   Unit 1 0.47 lb/mmBtu of heat input
   Unit 2 0.47 lb/mmBtu of heat input
   Unit 3 0.52 lb/mmBtu of heat input
   Unit 4 0.52 lb/mmBtu of heat input

2. The NO_x emission rate for each utility boiler shall be determined using the methods and procedures specified in NO_x RACT Plan Appendix A - Amendment 1, except that any reference to an annual average shall be read as a rolling 30-day average.

3. The Louisville Gas and Electric Company Mill Creek Generating Station (LG&E/MCGS) shall install, maintain, and operate a NO_x continuous emissions monitoring system (CEMS) for each utility boiler and shall keep records and submit reports and other notifications as specified in NO_x RACT Plan Appendix A - Amendment 1.

4. The LG&E/MCGS shall keep a record identifying all deviations from the requirements of this NO_x RACT Plan and shall submit to the District a written report of all deviations that occurred during the preceding calendar quarter. The report shall contain the following information:
   A. The boiler number,
   B. The beginning and ending date of the reporting period,
   C. Identification of all periods during which a deviation occurred,
   D. A description, including the magnitude, of the deviation,
   E. If known, the cause of the deviation, and
   F. A description of all corrective actions taken to abate the deviation.

   If no deviation occurred during the calendar quarter, the report shall contain a negative declaration. Each report shall be submitted within 30 days following the end of the calendar quarter.

5. In lieu of the requirements in this NO_x RACT Plan, the LG&E/MCGS may comply with alternative requirements regarding emission limitations, equipment operation, test methods, monitoring, recordkeeping, or reporting, provided the following conditions are met:
   A. The alternative requirements are established and incorporated into an operating permit pursuant to a Title V Operating Permit issuance, renewal, or significant permit revision process as established in Regulation 2.16,
   B. The alternative requirements are consistent with the streamlining procedures and guidelines set forth in section II.A. of *White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program*, March 5, 1996, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. The overall effect of compliance with alternative requirements shall consider the effect on an intrinsic basis, such as pounds per million Btu of heat input. However, alternative requirements that are developed based upon revisions to the applicable

requirements contained in 40 CFR Part 60 or Part 75 shall be approvable pursuant to this NO_x RACT Plan Element,

C. The U.S. Environmental Protection Agency (EPA) has not objected to the issuance, renewal, or revision of the Title V Operating Permit, and either

D. If the public comment period preceded the EPA review period, then the District had transmitted any public comments concerning the alternative requirements to EPA with the proposed permit, or

E. If the EPA and public comment periods ran concurrently, then the District had transmitted any public comments concerning the alternative requirements to EPA no later than 5 working days after the end of the public comment period.

The District's determination of approval of any alternative requirements is not binding on EPA. Noncompliance with any alternative requirement established pursuant to the Title V Operating Permit process constitutes a violation of this NO_x RACT Plan.

History: Approved 11-8-99; effective 1-1-00; amended a1/10-18-00 effective 1-1-01.

Appendix A to NO_x RACT Plan - Amendment 1
Requirements for NO_x CEMS

I. General Operating Requirements

A. Primary measurement requirements. The LG&E/MCGS shall, for each utility boiler, install, certify, operate, and maintain, in accordance with the requirements of 40 CFR 75 an oxides of nitrogen (NO_x) continuous emission monitoring system (CEMS), consisting of a NO_x pollutant concentration monitor and an oxygen (O_2) or carbon dioxide (CO_2) diluent gas monitor, with an automated data acquisition and handling system for measuring and recording NO_x concentration (in parts per million [ppm]), O_2 or CO_2 concentration (in percent O_2 or CO_2) and NO_x emission rate (in lb/mmBtu of heat input) discharged to the atmosphere. Any reference in this Appendix to an annual average shall be read as a rolling 30-day average. The LG&E/MCGS shall account for total NO_x emissions, both nitrogen oxide (NO) and nitrogen dioxide (NO_2), either by monitoring for both NO and NO_2 or by monitoring for NO only and adjusting the emissions data to account for NO_2.

B. Primary equipment performance requirements. The LG&E/MCGS shall ensure that each CEMS used to demonstrate compliance with the NO_x emission limit meets the equipment, installation, and performance specifications in 40 CFR 75 Appendix A, and is maintained according to the quality assurance and quality control procedures in 40 CFR 75 Appendix B. The NO_x emission rate for each utility boiler shall be recorded as lb/mmBtu of heat input.

C. Primary equipment hourly operating requirements.

1. The LG&E/MCGS shall ensure that all CEMS are in operation and monitoring the emissions from the associated utility boiler at all times that

the utility boiler combusts any fuel except during a period of any of the following:

a. Calibration, quality assurance, or preventive maintenance, any of which is performed pursuant to 40 CFR 75.21, 40 CFR 75 Appendix B, District regulations, District permit conditions, or this NO_x RACT Plan, or

b. Repair, backups of data from the data acquisition and handling system, or recertification, any of which is performed pursuant to 40 CFR 75.20.

2. The LG&E/MCGS shall ensure that the following requirements are met:

a. Each CEMS and component thereof is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval. The LG&E/MCGS shall reduce all volumetric flow, CO_2 concentration, O_2 concentration, NO_x concentration, and NO_x emission rate data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each 15- minute quadrant of an hour during which the utility boiler combusted fuel during that quadrant of the hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of the hour) if data are unavailable as a result of the performance of any activity specified in paragraph I.C.1. of this Appendix. The LG&E/MCGS shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.

b. Failure of a CO_2 or O_2 diluent concentration monitor, flow monitor, or NO_X pollutant concentration monitor to acquire the minimum number of data points for calculation of an hourly average shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. An hourly average NO_x emission rate in lb/mmBtu of heat input is valid only if the minimum number of data points are acquired by both the pollutant concentration monitor (NO_x) and the diluent monitor (CO_2 or O_2). If a valid hour of data is not obtained, the owner or operator shall estimate and record emissions, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in 40 CFR 75 Subpart D .

D. Optional backup monitor requirements. If the LG&E/MCGS chooses to use two or more CEMS, each of which is capable of monitoring the same stack or duct at a specific utility boiler, then the LG&E/MCGS shall designate one CEMS as the primary monitoring system and shall record this designation in the monitoring plan. The LG&E/MCGS shall designate any other CEMS as a backup CEMS in the monitoring plan. Any other backup CEMS shall be designated as a redundant backup CEMS, non-redundant backup CEMS, or reference method CEMS, as described in 40 CFR 75.20(d). When the certified primary monitoring system is operating and not out-of-control as defined in 40 CFR 75.24, only data from the certified primary monitoring system shall be reported as valid, quality-assured data. Thus, data from a backup CEMS may be reported as valid, quality-assured data only when a backup CEMS is operating and not out-of-control as defined in 40 CFR 75.24 or in the applicable reference method in 40 CFR 60 Appendix A and when the certified primary monitoring system is not operating or is operating but out-of-control. A particular monitor may be designated both as a certified primary monitor for one unit and as a certified redundant backup monitor for another unit.

E. **Minimum measurement capability requirements.** Each CEMS and component thereof shall be capable of accurately measuring, recording, and reporting data, and shall not incur a full scale exceedance, except as provided in section 2.1.2.5 of 40 CFR 75 Appendix A.

F. The LG&E/MCGS shall not operate a utility boiler so as to discharge, or allow to be discharged, emissions of NO_x to the atmosphere without accounting for all such emissions in accordance with the methods and procedures specified in this Appendix.

G. The LG&E/MCGS shall not disrupt the CEMS, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_x emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of this Appendix.

H. The LG&E/MCGS shall not retire or permanently discontinue use of the CEMS, any component thereof, or any other approved emission monitoring system under this Appendix except under any one of the following circumstances:

1. The LG&E/MCGS is monitoring NO_x emissions from the utility boiler with another certified monitoring system approved in accordance with the provisions of paragraph I.D. of this Appendix, or
2. The LG&E/MCGS submits notification of the date of certification testing of a replacement monitoring system.

I. The quality assurance and quality control requirements in 40 CFR 75.21 that apply to NO_x pollutant concentration monitors and diluent gas monitors shall be met. A NO_x pollutant concentration monitor for determining NO_x emissions shall meet the same certification testing requirements, quality assurance requirements, and bias test requirements as those specified in 40 CFR 75 for an SO_2 pollutant concentration monitor.

J. **Moisture correction.** If a correction for the stack gas moisture content is needed to properly calculate the NO_x emission rate in lb/mmBtu of heat input (i.e., if the

NO_x pollutant concentration monitor measures on a different moisture basis from the diluent monitor), LG&E/MCGS shall either report a fuel-specific default moisture value for each utility boiler operating hour, as provided in 40 CFR 75.11(b)(1), or shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in 40 CFR 75.11(b)(2). Notwithstanding this requirement, if Equation 19-3, 19-4 or 19-8 in Method 19 in Appendix A to 40 CFR Part 60 is used to measure NO_x emission rate, the following fuel-specific default moisture percentages shall be used in lieu of the default values specified in 40 CFR 75.11(b)(1): 5.0%, for anthracite coal; 8.0% for bituminous coal; 12.0% for sub-bituminous coal; 13.0% for lignite coal; and 15.0% for wood.

II. Specific Provisions for Monitoring NO_x Emission Rate (NO_x and diluent gas monitors)

A. The LG&E/MCGS shall meet the general operating requirements in 40 CFR 75.10 for a NO_x CEMS for each utility boiler. The diluent gas monitor in the NO_x CEMS may measure either O_2 or CO_2 concentration in the flue gases.

B. The LG&E/MCGS shall calculate hourly and rolling 30-day NO_x emission rates (in lb/mmBtu of heat input) by combining the NO_x concentration (in ppm), diluent concentration (in percent O_2 or CO_2), and percent moisture (if applicable) measurements according to the procedures in 40 CFR 75 Appendix F.

III. Monitoring plan

The LG&E/MCGS shall prepare and maintain a monitoring plan as specified in 40 CFR 75.53. The monitoring plan shall be submitted to the District no later than 45 days prior to the first scheduled certification test.

IV. Recordkeeping Provisions

A. The LG&E/MCGS shall maintain for each utility boiler a file of all measurements, data, reports, and other information required by this Appendix at the stationary source in a form suitable for inspection for at least 5 years from the date of each record. This file shall contain the following information:

1. The data and information required in paragraph IV.B. of this Appendix,
2. The component data and information used to calculate values required in paragraph IV.B. of this Appendix,
3. The current monitoring plan as specified in 40 CFR 75.53, and
4. The quality control plan as described in 40 CFR 75 Appendix B.

B. **NO_x emission record provisions.** The LG&E/MCGS shall record hourly the following information as measured and reported from the certified primary monitor, certified back-up or certified portable monitor, or other approved method of emissions determination for each utility boiler:

1. Date and hour,

2. Hourly average NO_x concentration (ppm, rounded to the nearest tenth),
3. Hourly average diluent gas concentration (percent O_2 or percent CO_2, rounded to the nearest tenth),
4. Hourly average NO_x emission rate (lb/mmBtu of heat input, rounded to nearest hundredth),
5. Hourly average NO_x emission rate (lb/mmBtu of heat input, rounded to nearest hundredth) adjusted for bias, if a bias adjustment factor is required by 40 CFR 75.24 (d),
6. Percent monitoring system data availability (recorded to the nearest tenth of a percent), calculated pursuant to 40 CFR 75.32,
7. Method of determination for hourly average NO_x emission rate using Codes 1-55 in 40 CFR 75.57 Table 4A, and
8. Unique code identifying emissions formula used to derive hourly average NO_x emission rate, as provided for in 40 CFR 75.53.

V. Certification, Quality Assurance, and Quality Control Record Provisions

A. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following:

1. Results of all trial runs and certification tests and quality assurance activities and measurements (including all reference method field test sheets, charts, records of combined system responses, laboratory analyses, and example calculations) necessary to substantiate compliance with all relevant requirements of this Appendix,
2. Bias test results as specified in 40 CFR 75 Appendix A, section 7.6.4,
3. The appropriate bias adjustment factor as follows:
    a. The value derived from Equations A-11 and A-12 in 40 CFR 75 Appendix A for any monitoring system or component that failed the bias test, or
    b. A value of 1.0 for any monitoring system or component that passed the bias test, and
4. The component/system identification code.

B. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following for all daily and 7-day calibration error tests, including any follow-up tests after corrective action:

1. Instrument span and span scale,
2. Date and hour,
3. Reference value (i.e., calibration gas concentration or reference signal value, in ppm or other appropriate units),
4. Observed value (monitor response during calibration, in ppm or other appropriate units), (flag if using alternative performance specification for low emitters or differential pressure monitors),
5. Percent calibration error (rounded to the nearest tenth of a percent),
6. Calibration gas level,
7. Test number and reason for test,

8. For 7-day calibrations tests for certification or recertification, a certification from the cylinder gas vendor or CEMS vendor that calibration gases as defined in 40 CFR 72.2 and 40 CFR 75 Appendix A were used to conduct calibration error testing,
9. Description of any adjustments, corrective actions, or maintenance following a test,
10. For quality test for off-line calibration, whether the unit is off-line or on-line, and
11. The component/system identification code.

C. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following for the initial and all subsequent linearity checks, including any follow-up tests after corrective action:

1. Instrument span and span scale,
2. Calibration gas level,
3. Date, hour, and minute of each gas injection at each calibration gas level,
4. Reference value (i.e., reference gas concentration for each gas injection at each calibration gas level, in ppm or other appropriate units),
5. Observed value (monitor response to each reference gas injection at each calibration gas level, in ppm or other appropriate units),
6. Mean of reference values and mean of measured values at each calibration gas level
7. Linearity error at each of the reference gases concentrations (rounded to the nearest tenth of a percent), (flag if using alternative performance specification),
8. Test number and reason for test (flag if aborted test),
9. Description of any adjustments, corrective action, or maintenance prior to a passed test or following a failed test,
10. The number of out-of-control hours, if any, following any tests, and
11. The component/system identification code.

D. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following information for the initial and all subsequent relative accuracy tests and test audits:

1. Reference method(s) used,
2. Individual test run data from the relative accuracy test audit for the NO_x pollutant concentration monitor or diluent gas monitor, including:
    a. Date, hour, and minute of beginning of test run,
    b. Date, hour, and minute of end of test run,
    c. Monitoring system identification code,
    d. Test number and reason for test,
    e. Operating load level (low, mid, high, or normal, as appropriate) and number of load levels comprising test,
    f. Normal load indicator for flow RATAs (except for peaking units),
    g. Units of measure,
    h. Run number,

- i. Run data from CEMS being tested, in the appropriate units of measure,
- j. Run data for reference method, in the appropriate units of measure,
- k. Flag value (0, 1, or 9, as appropriate) indicating whether run has been used in calculating relative accuracy and bias values or whether the test was aborted prior to completion,
- l. Average gross unit load (expressed as a total gross unit load rounded to the nearest MWe or as steam load rounded to the nearest thousand lb/hr), and
- m. Flag to indicate whether an alternative performance specification has been used,

3. Calculations and tabulated results, as follows:
   - a. Arithmetic mean of the monitoring system measurement values, reference method values, and of their differences, as specified in Equation A-7 in 40 CFR 75 Appendix A,
   - b. Standard deviation, as specified in Equation A-8 in 40 CFR 75 Appendix A,
   - c. Confidence coefficient, as specified in Equation A-9 in 40 CFR 75 Appendix A,
   - d. Statistical “t” value used in calculations,
   - e. Relative accuracy test results, as specified in Equation A-10 in 40 CFR 75 Appendix A,
   - f. Bias test results as specified in section 7.6.4 in 40 CFR 75 Appendix A,
   - g. Bias adjustment factor from Equation A-12 in 40 CFR 75 Appendix A for any monitoring system or component that failed the bias test (except as otherwise provided in section 7.6.5 in 40 CFR 75 Appendix A) and 1.000 for any monitoring system or component that passed the bias test,
   - h. F-factor value(s) used to convert NO_x pollutant concentration and diluent gas (O_2 or CO_2) concentration measurements into NO_x emission rates (in lb/mmBtu),
   - i. The raw data and calculated results for any stratification tests performed in accordance with sections 6.5.6.1 through 6.5.6.3 in 40 CFR 75 Appendix A, and
   - j. For moisture monitoring systems, the coefficient “K” factor or other mathematical algorithm used to adjust the monitoring system with respect to the reference method,
4. Description of any adjustment, corrective action, or maintenance prior to a passed test or following a failed or aborted test,
5. For each run of each test using Method 7E or 3A in Appendix A of 40 CFR 60 to determine NO_x, CO_2, or O_2 concentration the following:
   - a. Pollutant or diluent gas being measured,
   - b. Span of reference method analyzer,
   - c. Type of reference method system (e.g., extractive or dilution type),
   - d. Reference method dilution factor (dilution type systems, only),

e. Reference gas concentration (low, mid, and high gas levels) used for the 3-point, pre-test analyzer calibration error test (or, for dilution type reference method systems, for the 3-point, pre-test system calibration error test) and for any subsequent recalibrations,

f. Analyzer responses to the zero-, mid-, and high-level calibration gases during the 3-point pre-test analyzer (or system) calibration error test and during any subsequent recalibration(s),

g. Analyzer calibration error at each gas level (zero, mid, and high) for the 3-point, pre-test analyzer (or system) calibration error test and for any subsequent recalibration(s) (percent of span value),

h. Upscale gas concentration (mid or high gas level) used for each pre-run or post-run system bias check or, for dilution type reference method systems, for each pre-run or post-run system calibration error check,

i. Analyzer response to the calibration gas for each pre-run or post-run system bias (or system calibration error) check,

j. The arithmetic average of the analyzer responses to the zero-level gas, for each pair of pre- and post-run system bias (or system calibration error) checks,

k. The arithmetic average of the analyzer responses to the upscale calibration gas, for each pair of pre- and post-run system bias (or system calibration error) checks,

l. The results of each pre-run and each post-run system bias (or system calibration error) check using the zero-level gas (percentage of span value),

m. The results of each pre-run and each post-run system bias (or system calibration error) check using the upscale calibration gas (percentage of span value),

n. Calibration drift and zero drift of analyzer during each RATA run (percentage of span value),

o. Moisture basis of the reference method analysis,

p. Moisture content of stack gas, in percent, during each test run (if needed to convert to moisture basis of CEMS being tested),

q. Unadjusted (raw) average pollutant or diluent gas concentration for each run,

r. Average pollutant or diluent gas concentration for each run, corrected for calibration bias (or calibration error) and, if applicable, corrected for moisture,

s. The F-factor used to convert reference method data to units of lb/mmBtu (if applicable)

t. Date(s) of the latest analyzer interference test(s),

u. Results of the latest analyzer interference test(s),

v. Date of the latest NO_2 to NO conversion test (Method 7E only),

w. Results of the latest NO_2 to NO conversion test (Method 7E only), and

x. For each calibration gas cylinder used during each RATA, record the cylinder gas vendor, cylinder number, expiration date, pollutant(s) in the cylinder, and

6. The number of out-of-control hours, if any, following any tests, and
7. The component/system identification code.

VI. Notifications

A. The LG&E/MCGS or a designated representative shall submit notice to the District for the following purposes, as required by this Appendix:

1. Initial certification and recertification test notifications. Written notification shall be submitted of initial certification tests, recertification tests, and revised test dates as specified in 40 CFR 75.20 for continuous emission monitoring systems, except for testing only of the data acquisition and handling system, and
2. Notification of initial certification testing. Initial certification test notifications shall be submitted not later than 45 days prior to the first scheduled day of initial certification testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means at least 7 days prior to the original scheduled test date or the revised test date, whichever is earlier.

B. For retesting following a loss of certification under 40 CFR 75.20(a)(5) or for recertification under 40 CFR 75.20(b), notice of testing shall be submitted either in writing or by telephone at least 7 days prior to the first scheduled day of testing, except that in emergency situations when testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided by telephone or other means at least 2 business days prior to the original scheduled test date or the revised test date, whichever is earlier.

C. Notwithstanding the notice requirements of paragraph B. above, the LG&E/MCGS may elect to repeat a certification test immediately, without advance notification, whenever the LG&E/MCGS has determined during the certification testing that a test was failed or that a second test is necessary in order to attain a reduced relative accuracy test frequency.

D. Written notice shall be submitted, either by mail or facsimile, of the date of periodic relative accuracy testing performed under 40 CFR Part 75 Appendix B no later than 21 days prior to the first scheduled day of testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means acceptable to the District, and the notice is provided as soon as practicable after the new testing date is known, but no later than 24 hours in advance of the new date of testing.

E. Notwithstanding the notice requirements under paragraph D. above, the LG&E/MCGS may elect to repeat a periodic relative accuracy test immediately, without additional notification whenever the LG&E/MCGS has determined that a test was failed, or that a second test is necessary in order to attain a reduced relative accuracy test frequency. If an observer from the District is present when a test is rescheduled, the observer may waive all notification requirements under paragraph D. above for the rescheduled test.

VII. Quarterly reports

A. The LG&E/MCGS shall, within 30 days following the end of each calendar quarter, submit a report to the District that includes the following data and information for each utility boiler:

1. The information and hourly data required in this Appendix, including all emissions and quality assurance data, and
2. Average NO_x emission rate (lb/mmBtu of heat input, rounded to the nearest hundredth) during the rolling 30-day averaging periods.

B. The LG&E/MCGS shall submit a certification in support of each quarterly emissions monitoring report. This certification shall indicate whether the monitoring data submitted were recorded in accordance with the requirements of this Appendix. In the event of any missing data periods, this certification shall include a description of the measures taken to minimize or eliminate the causes for the missing data periods.

Appendix A to NOx RACT Plan - Amendment 2

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Attachment F – Cross-State Air Pollution Rule (CSAPR)

The owner or operator shall comply with the following requirements unless there are more current promulgated regulations:

I. Description of CSAPR Monitoring Provisions

The CSAPR subject units, and the unit-specific monitoring provisions at this source, are identified in the following tables. These units are subject to the requirements for the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program {please replace all Group 2 with Group 3}, and CSAPR SO_2 Group 1 Trading Program.

Unit ID: Unit 1, non-peaking coal-fired boiler with natural gas backup					
Parameter	CEMS requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X		----------------		
NO_X	X	-------------			
Heat input	X		----------------		

Unit ID: Unit 2, non-peaking coal-fired boiler with natural gas backup					
Parameter	CEMS requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X		----------------		
NO_X	X	-------------			
Heat input	X		----------------		

Unit ID: Unit 3, non-peaking coal-fired boiler with natural gas backup					
Parameter	CEMS requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X		----------------		
NO_X	X	-------------			
Heat input	X		----------------		

Unit ID: Unit 4, non-peaking coal-fired boiler with natural gas backup					
Parameter	CEMS requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75 subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75 appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X		----------------		
NO_X	X	-------------			
Heat input	X		----------------		

Unit ID: Unit 5, non-peaking natural gas-fired combustion turbine with natural gas-fired duct burners					
Parameter	CEMS requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75 subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75 appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2		X	----------------		
NO_X	X	-------------			
Heat input		X	----------------		

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