

*West Virginia Department of Environmental Protection
Harold D. Ward
Cabinet Secretary*

Major Source Construction Permit



R14-0042

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§22-5-1 et seq.) and 45 C.S.R. 13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation, and 45 C.S.R. 14 - Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration. The permittee identified at the above-referenced facility is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:

**Monarch Cloud Campus, LLC
Point Pleasant Campus
053-00136**

*Laura M. Crowder
Director, Division of Air Quality*

*Issued: **DRAFT***

Facility Location: 30 Monarch Way (The intersection of Ohio River Road (Route 62) and Airport Rd)
Point Pleasant, Mason County, West Virginia
Mailing Address: 109 North Post Oak Lane, Suite 140
Houston, TX 77024
Facility Description: Data Center with Power Generation with Power Nodes
NAICS Code: 518210 - Data Processing, Hosting, and Related Services
SIC Code: 7370 - Services - Computer Programming, Data Processing, Etc.
UTM Coordinates: 404.553 km Easting • 4,307.900 km Northing • Zone 17N
Latitude/Longitude: 38.914258°N / -82.100935°W
Permit Type: Major Source Construction
Description of Change: This action is for the construction of 3 data center halls with each hall containing 4 power nodes each for a total of 12 power nodes for the facility. Each individual power node will have 72 engine/generator sets to provide electricity for the power node. For the 12 power nodes, there will be a total of 864 engine/generators at the facility. Auxiliary emission units will consist of 4 emergency generators, 2 fire water pump engines, and 2 fuel gas heaters for each data center hall.

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified, or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

As a result of the granting of this permit, the source is a major source subject to 45CSR30. The permittee shall apply for a Title V (45CSR30) permit within 12 months in accordance with the requirements of 45CSR30 unless granted a deferral or exemption by the Director from such filing deadline pursuant to a request from the permittee.

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1.0. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
Power Nodes					
EU001 through EU072	EP1 through EP072	Power Node 1 (PN1) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	1C - 72C SCR & OxCat
EU073 through EU144	EP73 through EP144	Power Node 2 (PN2) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	73C - 144C SCR & OxCat
EU145 through EU216	EP145 through EP216	Power Node 3 (PN3) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	145C - 216C SCR & OxCat
EU217 through EU288	EP217 through EP288	Power Node 4 (PN4) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	217C - 288C SCR & OxCat
EU289 through EU360	EP289 through EP360	Power Node 5 (PN5) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	289C - 360C SCR & OxCat
EU361 through EU432	EP361 through EP432	Power Node 6 (PN6) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	361C - 432C SCR & OxCat
EU433 through EU504	EP433 through EP504	Power Node 7 (PN7) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	433C - 504C SCR & OxCat
EU505 through EU576	EP505 through EP576	Power Node 8 (PN8) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	505C - 576C SCR & OxCat
EU577 through EU648	EP577 through EP648	Power Node 9 (PN9) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	577C - 648C SCR & OxCat
EU649 through EU720	EP649 through EP720	Power Node 10 (PN10) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	649C - 720C SCR & OxCat
EU721 through EU792	EP721 through EP792	Power Node 11 (PN11) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	721C - 792C SCR & OxCat
EU793 through EU864	EP793 through EP864	Power Node 12 (PN12) - 72 Caterpillar 3520K Engines with Battery Storage System	2026	3,513 hp/engine	793C - 864C SCR & OxCat
EU883	EP883	Fuel Gas Heater 1 Indirect heat exchange, natural gas fired heater	2026	15.25 MMBtu/hr	None

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
EU884	EP884	Fuel Gas Heater 2 Indirect heat exchange, natural gas fired heater	2026	15.25 MMBtu/hr	None
EU885	EP885	Fuel Gas Heater 3 Indirect heat exchange, natural gas fired heater	2026	15.25 MMBtu/hr	None
EU886	EP886	Fuel Gas Heater 4 Indirect heat exchange, natural gas fired heater	2026	15.25 MMBtu/hr	None
EU887	EP887	Fuel Gas Heater 5 Indirect heat exchange, natural gas fired heater	2026	15.25 MMBtu/hr	None
EU888	EP888	Fuel Gas Heater 6 Indirect heat exchange, natural gas fired heater	2026	15.25 MMBtu/hr	None
EU865	EP865	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU895	EP895	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU866	EP866	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU896	EP896	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU867	EP867	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU897	EP897	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU868	EP868	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU898	EP898	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU869	EP869	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
EU899	EP899	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU870	EP870	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU900	EP900	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU871	EP871	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU901	EP901	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU872	EP872	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU902	EP902	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU873	EP873	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU903	EP903	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU874	EP874	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU904	EP904	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU875	EP875	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU905	EP905	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
EU876	EP876	Emergency Generator Make: Generac Model:SD1000 Engine Make: Perkins 30.6 liters, Compression-Ignition, Emergency Engine	2026	1,412 hp	None
EU906	EP906	Ultra Low Sulfur Diesel Tank	2026	2,000 gal	None
EU877	EP877	Fire Water Pump Make: Clark Model: JW6H-UFAD80 Engine Make: John Deere Model: 6090HFC47B 9.0 liters, Compression-Ignition, Emergency Engine EPA Engine Family No TJDXL09.0114	2026	400 hp	None
EU889	EP889	Ultra Low Sulfur Diesel Tank	2026	1,000 gal	None
EU878	EP878	Fire Water Pump Make: Clark Model: JW6H-UFAD80 Engine Make: John Deere Model: 6090HFC47B 9.0 liters, Compression-Ignition, Emergency Engine EPA Engine Family No TJDXL09.0114	2026	400 hp	None
EU890	EP890	Ultra Low Sulfur Diesel Tank	2026	1,000 gal	None
EU879	EP879	Fire Water Pump Make: Clark Model: JW6H-UFAD80 Engine Make: John Deere Model: 6090HFC47B 9.0 liters, Compression-Ignition, Emergency Engine EPA Engine Family No TJDXL09.0114	2026	400 hp	None
EU891	EP891	Ultra Low Sulfur Diesel Tank	2026	1,000 gal	None
EU880	EP880	Fire Water Pump Make: Clark Model: JW6H-UFAD80 Engine Make: John Deere Model: 6090HFC47B 9.0 liter, Compression-Ignition, Emergency Engine EPA Engine Family No TJDXL09.0114	2026	400 hp	None
EU892	EP892	Ultra Low Sulfur Diesel Tank	2026	1,000 gal	None

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
EU881	EP881	Fire Water Pump Make: Clark Model: JW6H-UFAD80 Engine Make: John Deere Model: 6090HFC47B 9.0 liter, Compression-Ignition, Emergency Engine EPA Engine Family No TJDXL09.0114	2026	400 hp	None
EU893	EP893	Ultra Low Sulfur Diesel Tank	2026	1,000 gal	None
EU882	EP882	Fire Water Pump Make: Clark Model: JW6H-UFAD80 Engine Make: John Deere Model: 6090HFC47B 9.0 liter, Compression-Ignition, Emergency Engine EPA Engine Family No TJDXL09.0114	2026	400 hp	None
EU894	EP894	Ultra Low Sulfur Diesel Tank	2026	1,000 gal	None

2.0. General Conditions

2.1. Definitions

- 2.1.1. All references to the “West Virginia Air Pollution Control Act” or the “Air Pollution Control Act” mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.
- 2.1.2. The “Clean Air Act” means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.
- 2.1.3. “Secretary” means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45 CSR §30-2.12.). The Director of the Division of Air Quality is the Secretary’s designated representative for the purposes of this permit.

2.2. Acronyms

CAAA	Clean Air Act Amendments	NO_x	Nitrogen Oxides
CBI	Confidential Business Information	NSPS	New Source Performance Standards
CEM	Continuous Emission Monitor	PM	Particulate Matter
CES	Certified Emission Statement	PM_{2.5}	Particulate Matter less than 2.5 µm in diameter
C.F.R. or CFR	Code of Federal Regulations	PM₁₀	Particulate Matter less than 10µm in diameter
CO	Carbon Monoxide	Ppb	Pounds per Batch
C.S.R. or CSR	Codes of State Rules	Pph	Pounds per Hour
DAQ	Division of Air Quality	Ppm	Parts per Million
DEP	Department of Environmental Protection	Ppm_v or ppmw	Parts per Million by Volume
dscm	Dry Standard Cubic Meter	PSD	Prevention of Significant Deterioration
FOIA	Freedom of Information Act	Psi	Pounds per Square Inch
HAP	Hazardous Air Pollutant	SIC	Standard Industrial Classification
HON	Hazardous Organic	SIP	State Implementation Plan
HP	NESHAP	SO₂	Sulfur Dioxide
lbs/hr	Horsepower	TAP	Toxic Air Pollutant
LDAR	Pounds per Hour	TPY	Tons per Year
M	Leak Detection and Repair	TRS	Total Reduced Sulfur
MACT	Thousand	TSP	Total Suspended Particulate
MDHI	Maximum Achievable Control Technology	USEPA	United States Environmental Protection Agency
MM	Maximum Design Heat Input	UTM	Universal Transverse Mercator
MMBtu/hr or mmbtu/hr	Million	VEE	Visual Emissions Evaluation
MMCF/hr or mmcf/hr	Million British Thermal Units per Hour	VOC	Volatile Organic Compounds
NA	Million Cubic Feet per Hour	VOL	Volatile Organic Liquids
NAAQS	Not Applicable		
NESHAPS	National Ambient Air Quality Standards		
	National Emissions Standards for Hazardous Air Pollutants		

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Act W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

- 2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation*; and
- 2.3.2. 45CSR14 – *Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration*.

2.4. Term and Renewal

- 2.4.1. This Permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked, or otherwise changed under an applicable provision of 45CSR13 or any other applicable legislative rule.

2.5. Duty to Comply

- 2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R14-0042, and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to.
[45CSR§§13-5.10 and 10.3.]
- 2.5.2. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA.
- 2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7.
- 2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses, and/or approvals from other agencies, i.e., local, state, and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13.

[45CSR§13-4.]

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.

[45CSR§13-5.4.]

2.10 Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.

[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

- a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit.
- b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit.
- c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
- d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

[WV Code §22-5-4(a)(9)]

2.12. Reserved

2.13. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it should have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or

reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13. [45CSR§13-10.1.]

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

- 3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association, or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]
- 3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow, or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]
- 3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management, and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40 CFR §61.145(b) and 45CSR§34]
- 3.1.4. **Odor.** No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1] *[State Enforceable Only]*
- 3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]
- 3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2.]

3.2. Monitoring Requirements

[Reserved]

3.3. Testing Requirements

- 3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling

connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

- a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.
- b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.
- c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.
- d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:
 1. The permit or rule evaluated, with the citation number and language.
 2. The result of the test for each permit or rule condition; and,
 3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

- 3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports, and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings

for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent two (2) years of data shall be maintained on site. The remaining three (3) years of data may be maintained off site, but must remain accessible within a reasonable time. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

- 3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.

[45CSR§4. State Enforceable Only.]

3.5. Reporting Requirements

- 3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
- 3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.
- 3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class or by private carrier with postage prepaid to the address(es), or submitted in electronic format by email as set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

DAQ: Director WVDEP Division of Air Quality 601 57 th Street Charleston, WV 25304-2345 DAQ Compliance and Enforcement¹: DEPAirQualityReports@wv.gov	US EPA: Section Chief U.S. Environmental Protection Agency, Region III Enforcement and Compliance Assurance Division Air Section (3ED21) Four Penn Center 1600 John F. Kennedy Boulevard Philadelphia, PA 19103-2852
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¹For all self-monitoring reports (MACT, GACT, NSPS, etc.), stack tests and protocols, Notice of Compliance Status Reports, Initial Notifications, etc.

- 3.5.4. The permittee shall submit reports of all required monitoring on or before September 15 for the reporting period January 1 to June 30 and March 15 for the reporting period July 1 to December 31. All instances of deviation from permit requirements must be clearly identified in such reports; and
- 3.5.5. The permittee shall submit to the Director on or before March 15, a certification of compliance with all requirements of this permit for the previous calendar year ending on December 31. If, during the previous annual period, the permittee had been out of compliance with any part of this permit, it shall be noted along with the following information: 1) the source/equipment/process

that was non-compliant and the specific requirement of this permit that was not met, 2) the date the permittee discovered that the source/ equipment/process was out of compliance, 3) the date the Director was notified, 4) the corrective measures to get the source/equipment/process back into compliance, and 5) the date the source began to operate in compliance. The submission of any non-compliance report shall give no enforcement action immunity to episodes of non-compliance contained therein.

3.5.6. Operating Fee

3.5.6.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall pay fees on an annual basis in accordance with 45CSR§30-8. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.6.2. In accordance with 45CSR30 – Operating Permit Program, enclosed with this permit is a Certified Emissions Statement (CES) Invoice, from the date of initial startup through the following June 30. Said invoice and the appropriate fee shall be submitted to this office no later than 30 days prior to the date of initial startup. For any startup date other than July 1, the permittee shall pay a fee or prorated fee in accordance with Section 4.5 of 45CSR22. A copy of this schedule may be found attached to the Certified Emissions Statement (CES) Invoice.

3.5.7. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Facility Wide Specific Requirements

4.1. Limitations and Standards

- 4.1.1. **Fugitive Dust Control:** The permittee shall maintain all paved and unpaved roadways at the facility in a manner that minimizes fugitive particulate matter (PM). All roadways that are used daily to support operations of the data center and/or the power nodes shall be paved. Specifically, the permittee shall apply control measures to all active unpaved roadways to prevent fugitive PM from being discharged beyond the facility's boundary lines. Unpaved road way at a minimum shall be improved with a base of no less than 4 inches of crusher run sized gravel. Other such control measures may include the application of water, chemical dust suppressants, or other measures that effectively reduce the silt loading of the roadway. Records of these control applications shall be maintained in accordance with Condition 3.4.1.

[45 CSR §14-8.3]

- 4.1.2. The permittee must reduce fugitive greenhouse gas emissions from the permitted facility by complying with the following requirements.
- a. The permittee shall develop and implement a monitoring plan in accordance with Condition 4.1.3.
 - b. The initial survey shall be conducted within six (6) months after startup of the first power node. As additional power nodes are started up, the additional components with the additional power node shall be surveyed within six (6) months after startup of the additional power node unless the annual survey is due within seven months from the date that additional power node was initially started up, then the additional components shall be surveyed during the annual survey.
 - c. Subsequent monitoring surveys shall be conducted at least annually and at least 30 days prior to any major planned maintenance outage. Major planned maintenance outage shall mean any planned outage that is scheduled for more than 14 days.
 - d. The fugitive emission components at the facility shall include all above grade components and equipment associated with the natural gas fuel supply piping, located on property owned by the permittee, that is connected to all the natural gas combustion sources covered under this permit.
 - e. Fugitive emissions are defined as: any visible emission from a fugitive emission component observed using optical gas imaging equipment or an instrument reading of 500 ppm or greater using Method 21.

The permittee shall repair all detected fugitive emissions in accordance with the following:

- i. Within 30 calendar days after detection; or
- ii. If the repair or replacement is technically infeasible, would require a vent blowdown, a facility shutdown, or is unsafe to repair during operation of the unit, then the repair or replacement must be completed during the next scheduled facility maintenance shutdown, after a planned vent blowdown, or within 2 years, whichever is the earliest.

- f. Once the repair or replacement is completed, the identified component shall be resurveyed as soon as practicable, but no later than 30 days after being repaired or 30 days after restarting the unit if a unit or station was shut down at the time of the repairs, to ensure that there are no fugitive emissions.
 - g. For repairs completed after the monitoring survey, the permittee may resurvey the repaired component using either U.S. EPA Method 21, Alternative Screening Procedure of Method 21, or optical gas imaging.
 - h. When using Method 21 to resurvey a repair, the fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above the background or when no soap bubbles are observed when the Alternative Screening Procedure is used. The procedures shall ensure that the surveys comply with the relevant sections of Method 21 at 40 CFR Part 60, appendix A-7, including Section 8.3.1. Use of the Alternative Screening Procedure must be conducted in accordance with the following:
 - i. Components that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Components that have these conditions present cannot be surveyed using the Alternative Screening Procedure.
 - ii. Spray a soap solution overall potential leak sources. The soap solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water. A pressure sprayer or squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detectable emissions or leaks as applicable. If any bubbles are observed, Method 21 instructions shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.
 - i. When using optical gas imaging to resurvey a repair, the fugitive emissions component is repaired when the optical gas imaging equipment shows no indication of visible emissions. The procedure outlined in Condition 4.1.4. must be followed.
- 4.1.3. The permittee shall develop a plan to monitor all fugitive emission components at the permitted facility. At a minimum, this fugitive emissions monitoring plan must include the elements specified as follows:
- a. Technique for determining fugitive emissions (i.e., Method 21 at 40 CFR part 60, appendix A-7, or optical gas imaging).
 - b. Manufacturer and model number of fugitive emissions detection equipment to be used.
 - c. Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. The permittee's repair schedule must meet the requirements of Condition 4.1.2.e.
 - d. Procedures and timeframes for verifying fugitive emission component repairs.
 - e. Records that will be kept and the length of time records will be kept.

- 4.1.4. If the permittee elects to use optical gas imaging techniques to conduct monitoring surveys, the plan must also include the following elements:
- a. Initial verification that the optical gas imaging equipment used in the survey meets the following:
 - i. The optical gas imaging equipment must be capable of imaging gasses in the spectral range for the compound of highest concentration in the potential fugitive emissions.
 - ii. The optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of less than 60 grams per hour from a quarter inch diameter orifice.
 - b. Procedures to perform a daily verification check of the equipment during periods of survey.
 - c. Procedure for determining the operator's maximum viewing distance from the components and how the operator will ensure that this distance is maintained.
 - d. Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.
 - e. Procedures for conducting surveys, shall include the following:
 - i. How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.
 - ii. How the operator will deal with adverse monitoring conditions, such as wind.
 - iii. How the operator will deal with interferences (e.g., steam).
 - f. Training and experience needed prior to performing surveys.
 - g. Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.
- 4.1.5. If the permittee elects to use Method 21 to conduct monitoring surveys, the plan must also include the following elements:
- a. Verification that the monitoring equipment meets the requirements specified in Section 6.0 of Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using an FID-based instrument. If the permittee wishes to use an analyzer other than an FID-based instrument, the permittee must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using an FID-based instrument (e.g., 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to the permittee's compound of interest).
 - b. Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.
- 4.1.6. The monitoring plan must include the following elements at the permitted facility:

- a. Sitemap.
 - b. A defined observation path that ensures that all fugitive emissions components are within sight of the path. The path must include distinguishable marking that indicates or identifies where the observation is being taken with relation to specific collection of fugitive components. The observation path must account for interferences.
 - c. If the permittee is using Method 21, the plan must also include a list of fugitive emissions components to be monitored and the method for determining location of fugitive emissions components to be monitored in the field (e.g., tagging, identification on a process and instrumentation diagram, etc.).
- 4.1.7. Each monitoring survey shall observe each fugitive emission component, any component that has the potential to emit fugitive emissions of GHG from components associated with the natural gas fuel supply piping, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.
- 4.1.8. The permittee may elect to switch between monitoring techniques in the monitoring plan. If such an election occurs, the permittee must update the monitoring plan as required in Condition 4.1.3. for the site and notify the Director in accordance with Condition 3.5.3. within 15 days prior to the next monitoring survey as required in Condition 4.1.2.c.
- 4.1.9. **Blowdown Emissions:** Emissions of Volatile Organic Compounds (VOC) and Greenhouse Gases (CO₂e) resulting from equipment depressurization, pigging, maintenance, and emergency shutdown testing shall not exceed the following limits on a 12-month rolling total basis:
- Volatile Organic Compounds (VOC): 0.83 tons per year.
 - Greenhouse Gases (CO₂e): 4,992.2 tons per year.

Event Frequency Limitations: To maintain compliance with the mass emission limits in Item 1, the permittee shall restrict blowdown and maintenance events to the maximum allowable frequencies specified below:

Table 4.1.9. Blowdown Frequency Limitations			
Equipment / Event Description	Equipment ID / Tag	Maximum Events per Month	Maximum Events per 12-Month Rolling Period
Emergency Shutdown Device (ESD) System Test	ESD-TEST	--	1 event
30-Inch Diameter Pig Launcher Blowdown	PL-30	3 events	12 events

Table 4.1.9. Blowdown Frequency Limitations

30-Inch Diameter Pig Receiver Blowdown	PR-30	3 events	12 events
24-Inch Diameter Pig Launcher Blowdown	PL-24	3 events	12 events
24-Inch Diameter Pig Receiver Blowdown	PR-24	3 events	12 events
V-1000 Filter Separator Maintenance Blowdown	FS-V1000	5 events	48 events

Work Practice Standards: Prior to initiating any manual atmospheric blowdown or maintenance venting event, the permittee shall properly isolate the equipment segment and reduce internal line pressure to the lowest practical operating pressure utilizing automated gas evacuation or line routing controls where available.

Compliance Demonstration & Calculation Methodology: Compliance with the monthly and 12-month rolling emission limits shall be demonstrated by calculating VOC and CO₂e mass emissions for each blowdown event using the following engineering equation:

$$E_{event} = \left(\frac{P \times V}{R \times T} \right) \times \sum (M_i \times MW_i)$$

Where:

- V = Internal volume of isolated pipe/vessel segment (cubic feet);
- P = Absolute pressure of segment prior to venting (psia);
- T = Absolute gas temperature prior to venting } (°R);
- M_i = Mole fraction of pollutant i (methane, CO₂, VOC) from continuous Gas Chromatograph;
- MW_i = Molecular weight of pollutant i ; and
- R = Universal gas constant.

- 4.1.10. The permittee shall install and maintain an industrial fence or acceptable physical barrier system around this permitted facility as outlined in Application R14-0042 prior to initial startup of the Power Node 1. This industrial fence shall be constructed and maintained in such a manner to prevent the public from accessing this permitted facility.

- 4.1.11. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all air pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.10.]

4.2. Monitoring Requirements

- 4.2.1. The permittee shall maintain records of each monitoring survey as required in Condition 4.1.2. Such records shall contain the following information:
- a. Date of the survey.
 - b. Beginning and end time of the survey.
 - c. Name of operator(s) performing survey. The permittee must note the training and experience of the operator.
 - d. Monitoring instrument used.
 - e. When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used to conduct the monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at the station embedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.
 - f. Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.
 - g. Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.
 - h. Documentation of each fugitive emission, including the information specified as follows:
 - i. Location.
 - ii. Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.
 - iii. Number and type of components for which fugitive emissions were detected.
 - iv. Number and type of fugitive emissions components that were not repaired as required in Condition 4.1.2.e.
 - v. A digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in Condition 4.1.2.e. The digital photograph or video must clearly identify the location of the component that must be repaired.

- vi. Repair methods applied in each attempt to repair the fugitive emissions components.
- vii. Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.
- viii. The date of successful repair of the fugitive emissions component.
- ix. Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

Such records shall be maintained in accordance with Condition 3.4.1. Any records submitted as required in Condition 4.5.2. in an electronic format shall be maintained in the electric format as submitted.

- 4.2.2. The permittee shall conduct an inspection of the entire facility for sources of fugitive PM emissions (e.g. haul roads, parking areas, storage areas, etc.) at least once per calendar month from March through November and once during the period from December through February. Any indications of fugitive PM emissions or equipment/control measure defect shall be recorded and the permittee shall implement a corrective action plan within 10 days of identifying the indication or defect. Records of the inspection results to include the date and time and inspector, and summary of corrective action taken with the date that the corrective action was fully implemented shall be maintained in accordance with Condition 3.4.1.
- 4.2.3. The permittee shall inspect the industrial fence/physical barrier system at least once every six months and if necessary make repair to the fence/barrier as necessary to ensure compliance with Condition 4.1.10. All repair attempts shall be made as soon as possible to include temporary repairs or alternative mechanisms to limit access to the facility from the public, with the first attempt within 24 hours of identifying the defect/failure and 30 days of making a final repair from the 1st day that the defect was identified. Records of such inspections and repairs shall be maintained in accordance with Condition 3.4.1.

4.3. Testing Requirements

[Reserved]

4.4. Recordkeeping Requirements

- 4.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:
 - a. The date, place as defined in this permit, and time of sampling or measurements.
 - b. The date(s) analyses were performed.
 - c. The company or entity that performed the analyses.
 - d. The analytical techniques or methods used.
 - e. The results of the analyses; and
 - f. The operating conditions existing at the time of sampling or measurement.

- 4.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.
- 4.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0., the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:
- The equipment involved.
 - Steps taken to minimize emissions during the event.
 - The duration of the event.
 - The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

- The cause of the malfunction.
 - Steps taken to correct the malfunction.
 - Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.
- 4.4.4. The permittee shall maintain an electronic **Blowdown Event Log** on-site. For each maintenance venting, pigging, ESD test, or filter separator blowdown event, the log shall record:
- Date, start time, and duration of atmospheric venting;
 - Equipment Tag ID and specific activity description;
 - Line pressure (psig) and temperature (°F) immediately prior to depressurization;
 - Calculated mass of VOC (lbs) and CO₂e (tons) emitted for the event; and
 - Running monthly count and 12-month rolling totals for event frequencies and mass emissions (tons/yr).

All logs shall be updated within five (5) business days of an event, and maintained in accordance with Condition 3.4.1.

4.5. Reporting Requirements

- 4.5.1. The permittee shall notify the Director within 15 days after installation of the permanent fence or physical barrier system as required in Condition 4.1.10. Such notification shall be made in accordance with Condition 3.5.3. Record of submission shall be maintained in accordance with Condition 3.4.1.

- 4.5.2. The permittee shall submit to the Director a report of each annual survey. Records of submissions shall be maintained in accordance with Condition 3.4.1. These reports shall contain the following information:
- a. Date of each monitoring survey.
 - b. Beginning and end time of each survey.
 - c. Name of operator(s) performing survey. If the survey is performed by optical gas imaging, the permittee must note the training and experience of the operator.
 - d. Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.
 - e. Monitoring instrument used.
 - f. Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.
 - g. Number and type of components for which fugitive emissions were detected.
 - h. Number and type of fugitive emissions components that were not repaired as required in Condition 4.1.2.e.
 - i. The date of successful repair of the fugitive emissions component.
 - j. Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.
 - k. Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

5.0. Source-Specific Requirements for Emission Units Associated with Power Nodes 1 through 12

The emission units in this section are the eight hundred and sixty-four (864) Caterpillar G3520K SI 4SLB natural gas-fired stationary internal combustion engines, each rated at 3,513 brake horsepower (equated to 21.17 MMBtu/hr of heat input per engine), with each engine connected to a 2,567 ekW generator (at 1.0 power factor).

Twelve (12) groups (Power Nodes) of seventy-two (72) engines coupled with a battery storage unit will be operated as an independent power node to support a dedicated data center (provide electrical power). Each power node will utilize a dedicated power management system that will optimize the actual operating load of the collection of engines assigned to the power node coupled with the battery storage system to the actual electrical power demand of the respective data center. Four (4) power nodes will support a data center (DC).

Each of these highly efficient natural gas-fired engines is designed around lean-burn combustion technology, which requires a sophisticated, closed-loop air-fuel ratio control (AFRC) system. The selected AFRC integrated with these engines is the manufacturer's ADEM A6 control system, designed to achieve high electrical efficiency (nominal heat rate of 7,746 Btu/ekW-hr at full load under ISO 3046/1 on a lower heating value [LHV] basis) while minimizing raw NO_x formation down to an engine-out rate of 0.5 g/bhp-hr. Each engine will be equipped with a dedicated upstream oxidation catalyst for the control of CO, VOCs, and hazardous air pollutants (HAPs), including formaldehyde, followed by a selective catalytic reduction (SCR) system utilizing an aqueous urea solution (Diesel Exhaust Fluid, or DEF) for post-combustion NO_x reduction.

Other requirements to optimize combustion efficiency and overall engine performance, the permittee will be required to use gas chromatography (GC) to determine critical fuel properties (e.g. heating value of the fuel). The efficient design and operation of the engines, along with combustion of pipeline-quantity natural gas exclusively will minimize emissions of PM/PM₁₀/PM_{2.5}, SO₂, and sulfur acid mist (SAM), and greenhouse gases (CO₂e).

For the following conditions in this section (5.0), the term "fleet" shall refer to the group of 72 engines for the dedicated power node.

5.1. Specific Requirements

5.1.1. **Equipment:** Caterpillar RICE: The permittee is authorized to install eight hundred and sixty-four (864) 3,513 hp Caterpillar Model G3520K SI 4SLB natural gas-fired stationary reciprocating internal combustion engines and associated generators, instrumentation, pumps, piping, DEF storage tanks, and other ancillary equipment necessary to operate the engines at the facility.

- a. Each engine shall utilize advanced lean-burn engine design, and shall be equipped with an air-to-fuel ratio controller (AFR) and electric ignition timing to maintain efficient fuel combustion in each cylinder.
- i. The permittee shall configure the engine electronic control system with a fuel heat content (LHV) set point representative of the pipeline-quality natural gas supplied to the facility. The permittee shall review the configured set point against the heating value data from the online gas chromatograph required by Condition 5.2.2 at least once per calendar quarter, and shall update the set point within 30 days whenever the rolling 30-day average LHV determined by the GC deviates from the configured value by more than ±3 percent. Records of each review and any set point update shall be maintained in accordance with Condition 3.4.1.
- ii. The permittee shall maintain an active feedforward controller for control of the urea dosing rate to the SCR. The feedforward control system shall utilize an automated,

model based algorithm to continuously set the urea dosing rate to mitigate unreacted NH₃ slip events.

- iii. The feedforward control system shall be engaged and active at all times when the engine is operating and the SCR catalyst inlet gas temperature has reached its minimum operating threshold ($\geq 300^{\circ}\text{C}$). The algorithm shall not be bypassed, disabled, or manually overridden during normal electrical power generation.
- b. Each engine shall be equipped with a non-resettable hour meter to indicate the elapsed engine operating time in cumulative hours.
- c. The permittee shall monitor the volumetric flow consumption at each engine as recorded by the engine controller(s).
- d. The power node level natural gas flow meters shall be totalled and compared against the volumetric flow rate recorded by the engine controller(s) on a quarterly basis.
- e. Each generator shall be equipped with a watt meter to measure the amount of electricity produced by each generator.

5.1.2. Add-on Control Technology:

- a. Selective Catalytic Reduction: The permittee shall install, tune, maintain and operate a selective catalytic reduction system on each engine to control emission of NO_x. The SCR systems shall be designed with a maximum ammonia slip of 10 ppmv at 15% O₂ evaluated on a 1-hour average basis. The injection system for the ammonia urea shall be adjusted as the engine operates across different operating loads. The permittee shall operate that SCR for each engine within the operating parameter (ammonia injection) rate established through Lead Unit Aftertreatment Verification Protocol testing as required in Condition 5.3.1. and with an inlet temperature of no less than 300°C.
- b. Oxidation Catalyst: The permittee shall install, maintain, and operate oxidation catalyst on each engine to control emissions of CO and VOC. The oxidation catalysts shall be designed to limit formaldehyde emissions to 4.3 parts per million by volume, dry basis, corrected to 15 percent oxygen, or reduce CO emissions by at least 93 percent, and achieve the VOC emissions concentrations in **Condition 5.1.6**. The oxidation catalyst inlet temperature and pressure drop shall be maintained in accordance with following specifications
 - i. Inlet Temperature greater than and equal to 450°F and less than or equal to 1,350°F.
 - ii. Differential pressures across the catalyst does not change by more than 2 inches of water column (inWC) at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial formaldehyde or CO reduction performance test.

5.1.3. Permitted Capacity: The maximum design heat input for each engine is 21.17 MMBtu per hour, higher heating value (HHV) basis with a maximum power output of 3,513 bhp at 100% load. The actual heat input may vary based on site-specific factors, such as ambient temperature, pressure, and relative humidity.

5.1.4. Authorized Fuel: The only fuel authorized to be fired in each engine is pipeline-quality natural gas. Combustion of pipeline-quality natural gas with a sulfur content of less than 0.20 grains per 100 standard cubic feet and good combustion practices shall be used to minimize emissions of

PM/PM₁₀/PM_{2.5}, SO₂, SAM, and greenhouse gases. Compliance with the fuel sulfur requirement shall be demonstrated by maintaining records of the weekly sulfur content analysis provided by the natural gas supplier or weekly gas sampling and analysis conducted by the permittee.

- 5.1.5. Restricted Operations: The hours of operation for each engine is not restricted (8,760 hours per year).
- 5.1.6. BACT Emission Standards: The following limits are the Best Available Control Technology (BACT) limits for these engines (EU001 through EU864). The averaging period for the limitation in the following subparagraphs shall be on a 3-hour average basis unless otherwise specified.
- a. NO_x Emission: As determined by reference method stack test, NO_x emissions from each engine shall not exceed 0.01 g/bhp-hr and 0.08 lb/hr.
 - b. CO Emissions: As determined by reference method stack test, CO emissions from each engine shall not exceed 0.027 g/bhp-hr, and 0.21 lb/hr.
 - c. VOC Emissions minus formaldehyde: As determined by reference method stack test, VOC emissions from each engine shall not exceed 0.02 g/bhp-hr, and 0.15 lb/hr. These limits do not include formaldehyde.
 - d. VOC Emissions: As determined by reference method stack test, VOC emissions from each engine shall not exceed 0.23 lb/hr. This limit includes formaldehyde emissions.
 - e. PM Emission: Filterable particulate matter for each engine shall not exceed 0.005 lb/hr on a 6-hour average.
 - f. PM₁₀ Emissions: As determined by reference method stack test, PM₁₀ emissions from each engine shall not exceed 0.01 lb/hr on a 6-hour average.
 - g. PM_{2.5} Emissions: As determined by reference method stack test, PM_{2.5} emissions from each engine shall not exceed 0.01 lb/hr on a 6-hour average.
 - h. SO₂ and SAM Emissions: As determined by reference method stack test, SO₂ emissions from each engine shall not exceed 0.01 lb/hr, and SAM emissions from each engine shall not exceed 0.0023 lb/hr. The primary means of compliance with these limits shall be demonstrated through compliance with the sulfur limitation in Condition 5.1.4.
 - i. GHG Emissions: Emissions of total greenhouse gases (CO₂e) shall not exceed 1,150 lb CO₂e/MWh on a gross electrical output basis, evaluated on a power node level using an 12-operating-month rolling average calculated based on fuel consumption using 40 CFR 98 default factors, HHV.
 - i. Gross heat rate across each fleet (power node) of engines (PN1, PN2, PN3, PN4, PN5, PN6, PN7, PN8, PN9, PN10, PN11, and PN12) shall not exceed 9,800 Btu/kWh (HHV) evaluated on a 12-operating-month rolling average basis.
 - ii. To minimize unburned methane slip (CH₄), the permittee shall install, maintain, and operate the engines with misfire detection systems during normal operation to avoid release of unburned methane.
- 5.1.7. HAP Emission Limits: The following limits are the Best Available Control Technology (BACT) limits for these engines (EU001 through EU864).

- a. Formaldehyde Emissions: As determined by reference method stack test, formaldehyde emissions from each engine shall not exceed 0.0095 g/hp-hr, and 0.07 lb/hr on a 3-hour average basis.
 - b. Total HAP Emissions: Total HAPs from each engine shall not exceed 0.16 lb/hr except during startup operation.
- 5.1.8. Annual Mass Emission Limitations (Tons Per Year) for each individual engine. These limits are on a 12-month rolling total basis.

Table 5.1.8. - Annual Engine Emission Limits	
Regulated Pollutant	Single Engine Limit (TPY)
NO _x	0.4055
CO	1.09
VOC	1.04
Formaldehyde (CH ₂ O)	0.35
PM	0.02
PM ₁₀ (Total)	0.05
PM _{2.5} (Total)	0.04
SO ₂	0.06
Sulfuric Acid Mist (SAM)	0.008
GHG (CO ₂ e)	12,727.91

- 5.1.9. Startup and Shutdown Event Restrictions: The permittee shall limit each startup or shutdown event for each engine to no more than 30 minutes per event and a total 35 hours for startup and shutdown events per year on a 12-month rolling total basis. A startup and shutdown are defined as:
- a. Startup Period: Defined as the period commencing with the initial firing of fuel gas in the engine cylinders and concluding when the engine reaches a minimum operating load of 50% AND the SCR catalyst inlet gas temperature reaches its minimum active operating threshold ($\geq 300^{\circ}\text{C}$), OR 30 minutes after initial fuel firing, whichever occurs first.
 - b. Shutdown Period: Defined as the period commencing when engine electrical load is intentionally reduced below 50% for the express purpose of bringing the engine to a complete stop (or when DEF injection is automatically terminated prior to engine stop) and concluding when fuel gas flow to the engine is completely terminated and cylinder combustion ceases. A shutdown event shall not exceed 15 minutes.

- c. The permittee shall restrict startup and shutdown events such that no more than one (1) Power Node (a maximum of 72 primary power engines) shall operate in startup or shutdown configuration during any single calendar hour.
 - d. Operation Limitation and Annual Caps:
 - i. Event Duration Caps: Individual startup events shall not exceed 30 minutes in duration (per 40 CFR 63 Subpart ZZZZ Table 2a). Individual shutdown events shall not exceed 15 minutes in duration.
 - ii. Annual Cycle & Hour Limitations: Each individual engine (EU-001 through EU-864) shall not exceed a cumulative total of 35.0 hours of startup and shutdown operation per rolling 12-month period.
 - iii. Mass Emission Limits During SUSD: Emissions of NO_x and CO during any calendar hour containing a startup or shutdown event shall be calculated using uncontrolled engine-out emission rates (0.50 g/hp-hr NO_x and 1.35 g/hp-hr CO) for the actual duration of the SUSD period.
 - e. Work Practice BACT Standards During SUSD:
 - i. Minimization of Idle & Transition Times: The permittee shall operate the automated Power Node Energy Management System (EMS) to minimize the duration of engine idling and startup steps to the minimum time necessary for safe mechanical loading and thermal stabilization.
 - ii. Automated Aftertreatment Interlock: The SCR controller shall automatically initiate DEF/urea injection as soon as the catalyst inlet exhaust gas temperature reaches 300°C, and shall not delay injection once minimum operating temperature and stable exhaust flow are established.
 - iii. Lean-Burn Control: Automated electronic air-fuel ratio controllers shall remain active during engine warm-up and ramp-down to minimize incomplete combustion and unburned hydrocarbon/methane slip.
- 5.1.10. Break-in Period Provision: To prevent poisoning and/or fouling of the SCR and Oxidation catalysts, the permittee may operate the engines without the catalyst installed.
- a. Authorization & Duration Limits
 - i. One-Time Initial Break-In Allowance: Each individual primary power engine (EU-001 through EU-864) is authorized a one-time initial commissioning "break-in" period not to exceed 50.0 cumulative operating hours per engine.
 - ii. Temporary Aftertreatment Exemption: During the authorized 50-hour break-in period, the engine may be operated without the Selective Catalytic Reduction (SCR) system and/or Oxidation Catalyst installed, or with aftertreatment control loops disengaged, solely to facilitate mechanical seating of engine piston rings, thermal stabilization, and lubrication oil consumption stabilization.
 - iii. Prohibition on Subsequent Operation: Beyond the cumulative 50.0 operating hours of initial break-in, no engine shall be operated for any purpose without the complete catalytic aftertreatment system (Oxidation Catalyst and SCR) fully installed, operational, and operating within certified parameters.

- b. Mandatory Catalyst Installation Interlock
 - i. Installation Deadline: Immediately upon reaching 50.0 operating hours (or earlier if the break-in protocol is completed), the permittee shall fully install, seal, and activate the Oxidation Catalyst and SCR system for that unit.
 - ii. Operational Control Loop Engagement: Prior to resuming power generation post-break-in, the permittee shall verify that all continuous monitoring interlocks (exhaust temperature sensors, differential pressure transmitters, and J1939 Smart NO_x sensors) are active and communicating with the ADEM A6 / Clean Emissions Module control architecture.
- c. Emissions Accounting & PTE Compliance
 - i. Uncontrolled Rate Application: All mass emissions (NO_x, CO, VOC, and Formaldehyde) generated during the 50-hour break-in period for each engine shall be calculated using uncontrolled engine-out emission factors (0.50 g/hp-hr NO_x, 1.35 g/hp-hr CO, 0.29 g/hp-hr VOC, and 0.19 g/hp-hr HCHO).
 - ii. Annual Mass Limit Inclusion: Mass emissions accrued during the 50-hour break-in period shall be tracked and incorporated into the facility's monthly and 12-month rolling total Potential to Emit (PTE) mass tracking logs for EU-001 through EU-864.

5.1.11. Additional PM/PM₁₀/PM_{2.5} and GHG BACT Work Practice Requirements:

- a. Fuel Temperature: The permittee shall maintain the fuel gas combusted by the engines in the OEM recommended temperature range of 50 °F to 140 °F.
- b. Engine Combustion Controls: The permittee shall operate the engines with misfire detection systems during normal operation to avoid release of unburned methane.
- c. Opacity Limit: Visible emissions from each engine exhaust stack shall not exceed 10% opacity based on a six-minute average, determined in accordance with 40 CFR Part 60, Appendix A-4, EPA Method 9.
- d. The exclusive combustion of pipeline-quality natural gas that complies with Condition 5.1.4.
- e. Operation and maintenance of each engine in accordance with manufacturer specifications and good combustion practices.

5.1.12. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.

[45CSR§13-5.10.]

5.2. Monitoring Requirements

- 5.2.1. **Continuous Parameter Monitoring System (CPMS) Requirement:** The permittee shall install, calibrate, maintain, and continuously operate an automated Data Acquisition and System Control (SCADA) / Energy Management System (EMS) architecture. The CPMS shall continuously measure, log, and calculate operational parameters across all 864 primary power natural gas

engines (EU-001 through EU-864) to verify compliance with emission limits, operational caps, and Best Available Control Technology (BACT) standards.

- a. Mandatory Monitored Parameters & Frequencies: The automated CPMS shall monitor and record the following parameters at the specified minimum frequencies:
 - i. Engine Operating Status & Electrical Output: Operating Mode (Off / Initial Break-In / Startup / Normal / Shutdown) [Logged continuously upon mode transition];
 - ii. Gross Electrical Output (kW and MW) per engine and per power node [15-minute averages]; and
 - iii. Total Operating Hours (Normal, SUSP, and Break-In) per engine [Recorded continuously, logged monthly].
- b. Fuel Consumption & Thermal Efficiency:
 - i. Natural Gas Volumetric Flow Rate (scf/hr) per engine, hall, and node [15-minute totals];
 - ii. Total Heat Input (MMBtu/hr, HHV) per engine [Calculated 15-minute averages]; and
 - iii. Gross Engine Heat Rate (Btu/kWh, HHV) per engine [12-month rolling average, calculated monthly].
- c. Aftertreatment System Parameters (Oxidation Catalyst & SCR):
 - i. Catalyst Inlet Exhaust Temperature (°F) for both Oxidation Catalyst and SCR beds [15-minute averages];
 - ii. Differential Pressure Drop (Delta P, inches H₂O) across the Oxidation Catalyst and SCR beds [Daily measurement while operating at ≥ 80% load];
 - iii. Reductant (DEF) Injection Rate (gal/hr or lb/hr) per engine [15-minute averages];
 - iv. Total Reductant (DEF) Volume Consumed (gallons) per engine, node, and facility-wide [Logged daily and aggregated monthly]; and
 - v. Post-Treatment Smart NO_x Sensor Output Signal (ppmv) over the engine controller area network [15-minute averages].
- d. Startup, Shutdown, and Break-In Event Interlocks:
 - i. Date, exact start time, and stop time (to the second) for each Startup and Shutdown event [Logged per event];
 - ii. Elapsed time (minutes) from initial fuel firing until SCR inlet temperature reaches 300°C and engine load reaches ≤ 50% [Logged per startup event]; and
 - iii. Cumulative Initial Break-In Operating Hours per engine serial number [Logged continuously up to the 50.0-hour hard limit].
- e. Compliance Aggregations and Calculated Metrics: On or before the 15th day of each calendar month, the permittee shall calculate and record the following aggregated compliance metrics for the preceding calendar month and the preceding 12-consecutive-month period:
 - i. Monthly & 12-Month Rolling Total Fuel Consumption (scf and MMBtu) per engine and facility-wide;

- ii. Monthly & 12-Month Rolling Total Operating Hours broken down by Normal Operation, SUSD Operation, and Break-In Mode for each engine;
 - iii. Monthly & 12-Month Rolling Total SUSD Cycles per engine;
 - iv. Monthly & 12-Month Rolling Total DEF/Urea Consumption (gallons) facility-wide; and
 - v. 12-Month Rolling Average Gross Heat Rate (Btu/kWh, HHV) across the engine fleet to demonstrate compliance with the 9,800 Btu/kWh (HHV) BACT limit.
- f. Parameter Excursions & Deviation Reporting Interlock: The permittee shall record an operational excursion and report a compliance deviation in the semi-annual monitoring report for any occurrence of the following parameter boundary conditions:
- i. Oxidation Catalyst Temperature: Any 4-hour rolling average catalyst inlet temperature falling below 450°F (232°C) or exceeding 1,350°F (732°C) during normal operation (per 40 CFR 63 Subpart ZZZZ);
 - ii. Catalyst Differential Pressure: Any measured pressure drop across the Oxidation Catalyst or SCR bed that deviates by more than ± 2.0 inches H₂O from the baseline pressure drop established during the most recent compliant performance stack test;
 - iii. SCR Temperature Interlock: Any period during normal operation (load $\geq 50\%$) where the SCR catalyst inlet gas temperature falls below 300°C while DEF injection is active or required;
 - iv. Startup/Shutdown Event Excursions: Any individual startup event exceeding 30 minutes, any individual shutdown event exceeding 15 minutes, or any engine exceeding 70 SUSD cycles or 35.0 SUSD hours per 12-month rolling period; and
 - v. Break-In Mode Limit: Any engine operated beyond 50.0 cumulative hours without the catalyst skid installed and operational.
- g. Data Retention Standard: All CPMS raw data logs, 15-minute parameter averages, daily pressure differential records, monthly aggregations, and 12-month rolling calculations shall be maintained in accordance with Condition 3.4.1.

5.2.2. Continuous Online Gas Chromatograph (GC) Monitoring, Quality Assurance/Quality Control (QA/QC), and Fuel Sampling Architecture (EU-001 through EU-864)

a. Sampling Location Architecture & Representativeness Requirement

Mandatory Representativeness Standard: The permittee shall install, calibrate, maintain, and continuously operate an online C6+ (or extended C9+) Gas Chromatograph (GC) system, or may contract with/utilize a third-party owned and operated online GC system located at the fuel gas custody transfer point or location that the gas being sampled is representative of the fuel gas for the permitted facility, configured to sample fuel gas that is fully representative of all natural gas combusted across the primary engine fleet (EU-001 through EU-864).

Dual Supply Pipeline Provisions: If the facility receives fuel gas from two (2) or more independent supply pipelines, laterals, or interconnects, the permittee shall satisfy fuel representation through one of the following binding configurations prior to initial engine operation:

Option A (Single Downstream Blended Header GC): Install a single online GC with a sample probe located on a common, fully mixed downstream supply header located after the blending point of all incoming gas pipelines. The permittee shall demonstrate that no unmeasured gas from any individual supply line can bypass this sampling point to feed any engine hall or node.

Option B (Dedicated Pipeline GCs): Install a dedicated, independent online GC on each individual incoming supply pipeline/header prior to distribution.

Option C (Automated Multi-Stream Dual-Header GC): Install a single online GC equipped with an automated, heated, multi-stream sampling selector valve system that alternates sampling between both incoming supply pipelines. Stream switching shall occur at a frequency not to exceed 15 minutes per stream, ensuring that every supply line is analyzed at least twice per hour.

Prohibition on Unmonitored Fuel: At no time shall any engine (EU-001 through EU-864) combust natural gas that has not passed through a certified online GC sampling loop.

b. Measured Fuel Parameters and Sampling Frequency

Minimum Analyzed Constituents: The online GC system shall measure and report molar fractions (mole %) of methane (C1), ethane (C2), propane (C3), i-butane (i-C4), n-butane (n-C4), i-pentane (i-C5), n-pentane (n-C5), hexanes plus (C6+), carbon dioxide (CO2), and nitrogen (N2).

Calculated Fuel Metrics: The GC system (or integrated SCADA processor) shall automatically calculate and report the following metrics for every sample cycle:

- i. Gross / Higher Heating Value (HHV, Btu/scf, dry basis);
- ii. Net / Lower Heating Value (LHV, Btu/scf, dry basis); and
- iii. Fuel Specific Gravity (SpGr).

Sampling Frequency: The online GC shall complete a full chromatographic analysis cycle and update all calculated metrics in the facility SCADA/EMS at least once every 15 minutes (minimum 4 complete analyses per hour, per active sampling stream).

c. Quality Assurance / Quality Control (QA/QC) Standards

Analytical Test Standards: The GC system shall be operated, calibrated, and maintained in accordance with GPA Standard 2261 or ASTM D1945. Heating values and specific gravity shall be calculated in accordance with GPA Standard 2172 or ASTM D3588.

Daily Automated Validation Check: The GC system shall perform an automated daily single-point calibration validation check using a certified, NIST-traceable natural gas reference standard. If the measured HHV or component concentrations deviate by more than $\pm 1.0\%$ from the certified cylinder value, the GC shall automatically initiate a full calibration sequence.

Quarterly Accuracy Audits: At least once per calendar quarter (spaced at least 60 days apart), the permittee shall perform a multi-point accuracy audit using an independent certified reference gas mixture.

Reference Gas Certification: All calibration and audit gas cylinders shall have a certified laboratory analysis traceable to NIST standards and shall be replaced prior to cylinder expiration or when cylinder pressure drops below 150 psig.

d. Instrument Availability (Uptime) & Fallback Sampling Protocol

Minimum Operational Uptime Standard: The online GC system shall achieve a minimum data availability/uptime of 95.0% per calendar quarter. Valid operational hours exclude routine automated calibration checks (not to exceed 30 minutes per day).

Backup Manual Sampling Protocol (GC Outage): During any period when the online GC system is offline due to malfunction, maintenance, or repair:

- i. Outages ≤ 8 Hours: The SCADA/EMS shall apply the average fuel HHV and composition logged during the preceding 24 hours of normal GC operation.

- ii. Outages > 8 Hours: The permittee shall collect a manual pressurized gas grab sample at least once per 24-hour period using a heated sample cylinder per GPA Standard 2166 / ASTM D1145. Manual samples shall be submitted to an independent accredited laboratory for analysis per GPA 2261 / ASTM D1945 within 24 hours of collection.
- iii. Extended Outages > 7 Consecutive Days: The permittee shall submit a written notification to the Director within 10 business days detailing the cause of the GC failure, corrective actions taken, and an enforceable schedule for restoring automatic online GC monitoring.

5. SCADA Integration and Data Retention

Live EMS Integration: Real-time 15-minute HHV outputs (Btu/scf) from the GC shall be directly linked to the SCADA/EMS fuel monitoring system to continuously calculate hourly heat input (MMBtu/hr) and 12-month rolling average engine gross heat rate (Btu/kWh, HHV).

Record Retention: The permittee shall maintain all GC raw chromatograms, daily calibration logs, quarterly audit reports, reference gas certificates of analysis, and 15-minute composition records on-site for a period of at least five (5) years, available for inspection upon request.

5.2.3. Periodic Engine Emission Screening Monitoring (NO_x, CO, and O₂) (EU-001 through EU-864)

- a. Sampling Frequency & Fleet Rotation Schedule:
 - 1. The permittee shall conduct periodic emission screening monitoring for NO_x, CO, and O₂ on a rotating schedule across all twelve (12) Power Nodes (EU-001 through EU-864).
 - 2. In each calendar quarter, the permittee shall perform screening monitoring on at least six (6) engines per Power Node (totaling 72 engines screened per quarter, or 288 engines screened annually). Sampling shall be rotated such that every individual engine undergoes periodic screening at least once every three (3) calendar years.
 - 3. If a designated engine is out of service during a scheduled quarterly monitoring event, the screening requirement for that unit is suspended for that quarter, provided the SCADA system logs the out-of-service hours.
 - 4. Any engine undergoing major overhaul, SCR catalyst replacement, or oxidation catalyst replacement shall undergo screening monitoring within 14 operating days following return to service.
- b. Instrument Performance & Monitoring Methodology:
 - 1. Monitoring shall be conducted using a low-range portable electrochemical cell analyzer (0.1 ppm resolution) or a portable optical analyzer (FTIR or NDIR) operating in accordance with EPA CTM-030, CTM-034, or ASTM D6522.
 - 2. To ensure accuracy at ultra-low concentration BACT limits, calibration span gases shall not exceed 20.0 ppmvd for NO_x and 50.0 ppmvd for CO.
 - 3. Screening shall consist of one (1) continuous monitoring run of at least 15 minutes of stable data collection while the engine operates at normal base load ($\geq 80\%$ rated load).
 - 4. Measured NO_x and CO concentration readings shall be corrected to fifteen percent (15%) oxygen (dry basis) using the standard correction formula:

$$\text{Concentration}_{@ 15\% \text{ O}_2} = \text{Concentration}_{\text{measured}} \times [(20.9 - 15.0) / (20.9 - \% \text{O}_{2,\text{measured}})]$$

c. Corrective Action & Trigger Thresholds:

If the corrected screening concentration exceeds 1.0 ppmvd NO_x @ 15% O₂ or 4.0 ppmvd CO @ 15% O₂:

1. The permittee shall record the excursion and initiate corrective tuning actions (e.g., DEF dosing adjustment, air-fuel ratio calibration, or catalyst inspection) within 24 hours.
2. The permittee shall repeat the screening test within 72 hours of completing corrective actions.
3. If the re-test fails or indicates catalyst degradation, the engine shall be scheduled for formal testing or catalyst maintenance, and the event shall be logged in the SCADA deviation log.

d. Step-Down Provision:

1. If all sampled engines within a Power Node demonstrate corrected concentrations less than 1.0 ppmvd NO_x and 4.0 ppmvd CO for four (4) consecutive quarters, the quarterly screening frequency for that specific Power Node may be reduced to semi-annual.
2. If any subsequent semi-annual test exceeds these thresholds, the Power Node shall immediately revert to quarterly monitoring until the above step-down criteria are met again.

e. Recordkeeping Requirements:

Records of periodic monitoring shall be maintained on-site for five (5) years and include:

1. Date, start/stop time, Engine ID, and Power Node assignment;
2. Engine operating load (BHP or kW) and fuel consumption rate (scf/hr);
3. Raw measured concentrations (ppmv NO_x, ppmv CO, and % O₂);
4. Corrected concentrations (ppmvd NO_x @ 15% O₂ and ppmvd CO @ 15% O₂);
5. Analyzer make, model, serial number, sensor resolution specs, and NIST-traceable calibration gas certificates; and
6. Technician name and details of any engine/aftertreatment tuning performed.

- 5.2.4. To demonstrate ongoing compliance with the visible emissions limit of Condition 5.1.11.c, the permittee shall conduct periodic tiered visible emissions monitoring of Emission Points EP001 through EP864 during normal operation of the engines. Visible emissions observations under this condition shall not be conducted within 30 minutes of engine startup or 15 minutes prior to a scheduled engine shutdown.

a. Tier 1 Screening (U.S. EPA Method 22):

- i. The permittee shall conduct a visible emissions observation using U.S. EPA Method 22 (40 CFR Part 60, Appendix A-7) at least once per calendar half-year (semi-annually) for each operational engine.

- ii. The Method 22 observation shall be conducted for a continuous duration of at least six (6) minutes while the engine is operating under normal load conditions firing natural gas.
 - iii. If no visible emissions are observed, or if visible emissions are observed for less than thirty (30) seconds during the 6-minute observation period, the engine is deemed in compliance with the opacity standard, and no further action is required for that monitoring period.
 - b. Tier 2 Quantification (U.S. EPA Method 9) and Corrective Action:
 - i. If visible emissions are observed for thirty (30) seconds or more during a Tier 1 screening, the permittee shall log a screening failure and perform one of the following actions:
 - ii. Immediate Maintenance and Re-Screening: The permittee may shut down the engine, perform corrective maintenance (e.g., air-fuel ratio control adjustment, spark plug replacement, or engine tuning), and restart the unit. Within twenty-four (24) operating hours of restarting the unit, the permittee shall conduct a new Tier 1 Method 22 screening while operating under normal load. If the unit passes the new screening, no Method 9 observation is required.
 - iii. Method 9 Evaluation: If corrective maintenance is not performed, or if the engine fails the subsequent Tier 1 re-screening, the permittee shall conduct a formal U.S. EPA Method 9 observation (40 CFR Part 60, Appendix A-4) within seventy-two (72) hours of the failed Tier 1 screening (or within 24 operating hours of the next engine restart if the unit is taken offline). The Method 9 observation must be conducted by a certified visible emissions evaluator while the engine is operating under normal load to determine compliance with the 10% opacity standard. A 6-minute average opacity exceeding 10% shall constitute an exceedance of Condition 5.1.11.c and a reportable deviation.
 - c. Recordkeeping Requirements:

The permittee shall maintain records of all visible emissions monitoring in accordance with Condition 3.4.1. Records shall include:

 - i. The date, time, engine ID (EP001 through EP864), and operating load of all Method 22 and Method 9 observations.
 - ii. The name, affiliation, and (if applicable) a copy of the current Method 9 certification for the observer.
 - iii. The results of the observations, including total accumulated time of visible emissions during Method 22 checks, and the calculated 6-minute averages for any Method 9 checks.
 - iv. Details of any corrective maintenance, engine tuning, or repairs performed as a result of a failed Tier 1 screening.
- 5.2.5. **Break-in Period:** The permittee shall record the following information on each engine during the 50-hr break-in period as allowed in Condition 5.1.10.:
- a. Individual Unit Hour Logging: The facility SCADA/EMS system shall automatically track and record the cumulative operating hours in "Break-In Mode" for every individual engine serial number.
 - b. Break-In Completion Recordkeeping: For each engine, the permittee shall maintain an on-site log containing:

- i. Engine Serial Number and Node/Hall Assignment;
- ii. Date and exact time of initial fuel firing (Hour 0.0);
- iii. Cumulative operating hours logged in break-in mode;
- iv. Date and time when the 50-hour break-in period was completed (or terminated) for the engine; and
- v. Date, time, and technician sign-off confirming physical catalyst installation and SCR control loop activation.

Such records shall be maintained in accordance with Condition 3.4.1.

Compliance Reporting: The status of engine break-in completion across the fleet shall be summarized and submitted to the DAQ in the standard Semi-Annual Monitoring and Compliance Report.

- 5.2.6. For the purpose of demonstrating compliance for the SO₂ and H₂SO₄ BACT limits in Condition 5.1.6.h. and the fuel sulfur limit in Condition 5.1.4., the permittee shall make a demonstration that the fuel (pipeline quality natural gas) combusted in engines EU001 through EU864 and fuel gas heater EU883 through EU888 contains a sulfur content of no greater than 0.2 grains/100 scf using one of the following source information:

a. Fuel Quality & Sulfur Content Limitation

- Pipeline-Quality Natural Gas Requirement: The permittee shall combust pipeline-quality natural gas exclusively in all primary power engines (EU-001 through EU-864).
- Maximum Fuel Sulfur Cap: The total sulfur content of the natural gas combusted across the facility shall not exceed 0.2 grains of sulfur per 100 standard cubic feet (0.2 gr S / 100 scf), dry basis.

b. Compliance Demonstration & Monitoring Options

The permittee shall demonstrate continuous compliance with the 0.2 gr S / 100 scf fuel sulfur limit through one (or a combination) of the following options:

- Current Tariff Sheet or Gas Contract Guarantee: Maintaining a current, valid tariff sheet, Federal Energy Regulatory Commission (FERC) gas tariff, or commercial gas purchase contract certifying that the natural gas supply has a total sulfur content of ≤ 0.2 gr S / 100 scf. Tariff documentation shall be re-verified at least once per calendar year or whenever a contract/tariff revision occurs.
- Fuel Supplier Certificates of Analysis: Obtaining monthly Certificates of Analysis (COA) from the natural gas supplier(s) documenting the total sulfur content (gr S / 100 scf or ppmv) of the gas delivered to the facility site.
- Periodic Laboratory Fuel Sampling & Testing: In the absence of a qualifying tariff or supplier COA guaranteeing ≤ 0.2 gr S / 100 scf, the permittee shall collect a representative fuel gas sample at least once per week (spaced at least 3 days apart) and analyze total sulfur content using one of the following recognized analytical methods:
 - ASTM D1072: *Standard Test Method for Total Sulfur in Fuel Gases*;

- ASTM D3246: *Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry*;
- ASTM D4468: *Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry*;
- ASTM D5504 / D6228: *Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence/Sulfur Selective Detection*.

c. Dual Supply Line Provisions

If natural gas is supplied to the facility via two (2) or more independent incoming pipelines or interconnects, the permittee shall verify and document compliance with the 0.2 gr S / 100 scf limit for each incoming supply line independently using the options outlined in Section (b).

d. Excursion Thresholds & Corrective Actions

- Excursion Reporting: If any tariff sheet revision, supplier COA, or quarterly laboratory test reveals a fuel sulfur content exceeding 0.2 gr S / 100 scf, the permittee shall record an operational excursion and submit a written deviation report to the Director within five (5) business days.
- Re-Sampling Requirement: If an excursion is identified via laboratory testing, the permittee shall re-sample and re-analyze the fuel gas within forty-eight (48) hours of receiving the non-compliant laboratory result. If non-compliant fuel persists, the permittee shall update facility mass emission tracking logs to reflect actual measured sulfur rates.

e. Recordkeeping

The permittee shall maintain the following records in accordance with Condition 3.4.1.:

- Copies of all current natural gas tariff sheets, FERC gas tariffs, or supplier contracts;
- All supplier Certificates of Analysis (COAs) received;
- All laboratory test reports, sampling dates, chain-of-custody records, and analytical test results for total fuel sulfur content; and
- Logs of any fuel sulfur excursions and corresponding written notifications submitted to the Director.

5.3. Testing Requirements

- 5.3.1. **Comprehensive Engine Performance Testing and Lead Unit Aftertreatment Verification Protocol (EU-001 through EU-864):** To demonstrate compliance with the applicable emission limits set forth in Section 5.1.(Conditions 5.1.6. and 5.1.7.) — specifically for NO_x, CO, VOC, Formaldehyde (CH₂O), Ammonia (NH₃) slip, and to satisfy the federal testing requirements of **40 CFR 60 Subpart JJJJ (60.4243(b)(2)(ii) and 40 CFR 63 Subpart ZZZZ**, the permittee shall conduct performance testing on **one hundred percent (100%) of the engines** in the primary power natural gas fleet (EU-001 through EU-864), combined with a Lead Engine aftertreatment

verification protocol for each 72-engine Power Node fleet, in accordance with Condition 3.3.1 and the following specific provisions:

a. 100% Engine Performance Testing Mandate & Schedule:

- i. **Initial Performance Testing (All 864 Engines):** The permittee shall conduct initial performance testing on **every individual engine (EU-001 through EU-864)**. Testing for each engine shall be completed within sixty (60) days after achieving maximum operating load, but no later than one hundred eighty (180) days after initial startup of that specific unit.
- ii. **Subsequent Recurring Performance Testing (All 864 Engines):** Pursuant to 40 CFR 60 Subpart JJJJ and 40 CFR 63 Subpart ZZZZ, **every individual engine** shall undergo subsequent compliance performance testing every **8,760 operating hours or three (3) calendar years**, whichever comes first, calculated from the date of the previous successful test for that specific engine serial number.

b. Lead Engine SCR Dosing Algorithm & Part-Load Verification Protocol

- i. **Lead Engine Designation:** For each newly commissioned 72-engine Power Node fleet, the permittee shall designate one (1) representative engine as the "Lead Test Engine" for aftertreatment algorithm verification.
- ii. **14 to 30-Day Portable CEMS Verification:** Within sixty (60) days after initial startup of each Power Node, the permittee shall equip the Lead Test Engine with a portable CEMS and continuously log 15-minute average data for (NO_x ppmvd @ 15% O₂), O₂ (%), engine load (kW/BHP), SCR inlet temperature (°F), DEF injection rate (gal/hr), and output from the post-catalyst Smart NO_x sensor for a continuous period of **14 to 30 operating days**.
- iii. **Part-Load & Ammonia Slip Spot-Checks:** During the 14 to 30-day window, the permittee shall execute discrete steady-state test runs on the Lead Test Engine at **70%, 85%, and 100% operating load** to verify the ADEM A6 controller map. At each load step, unreacted Ammonia (NH₃) slip shall be measured using EPA CTM-027, EPA Method 320, or ASTM D6348 across three (3) 30-minute runs.
- iv. **ADEM A6 Controller and CEM Controller Re-Mapping:** If 15-minute average NO_x exceeds **2.0 ppmvd @ 15% O₂** or if NH₃ slip exceeds **10.0 ppmvd @ 15% O₂** at any load step, the permittee shall re-tune/re-map the ADEM A6 urea dosing control algorithm within seven (7) calendar days and deploy the updated dosing map across all 72 engines within that Power Node fleet.

c. Reference Test Methods & Oxygen Correction Basis

All pollutant concentration measurements shall be corrected to **fifteen percent (15%) oxygen (O₂), dry basis**. Testing shall be conducted using the following reference methods:

- **Oxygen (O₂) and Carbon Dioxide (CO₂):** U.S. EPA Method 3A or ASTM D6348 shall be used to measure exhaust gas O₂ and CO₂ concentrations for moisture and dilution correction.
- **Nitrogen Oxides (NO_x):** U.S. EPA Method 7E, EPA Method 320 (FTIR), or ASTM D6348 shall be used to determine NO_x emissions.

- **Carbon Monoxide(CO) & Destruction Efficiency:** U.S. EPA Method 10, EPA Method 320, or ASTM D6348 shall be used to measure CO concentration and verify a minimum **93% CO destruction efficiency** across the Oxidation Catalyst (per 40 CFR 63 Subpart ZZZZ Table 2a).
- **Volatile Organic Compounds (VOC):** U.S. EPA Method 25A shall be used to determine Total Hydrocarbons (THC). Concurrent measurement of Methane (CH₄) and Ethane (C₂H₆) shall be conducted using U.S. EPA Method 18, EPA Method 320, or ASTM D6348. Net non-methane/non-ethane VOC emissions shall be determined by subtracting measured methane and ethane from total THC, converted and reported on a **Propane (C₃H₈) basis (MW = 44.10 lb/lb-mol)**.
- **Formaldehyde (CH₂O):** U.S. EPA Method 320 (FTIR), ASTM D6348, or U.S. EPA Method 323 shall be used to verify compliance with the stack limit and/or Subpart ZZZZ standard (< 14.0 ppmvd @ 15% O₂).
- **Ammonia (NH₃) Slip:** EPA Conditional Test Method 027 (CTM-027), EPA Method 320, or ASTM D6348 shall be used to determine unreacted ammonia slip downstream of the SCR catalyst (≤ 10.0 ppmvd @ 15% O₂).

d. Operational Load & Fuel Requirements During Testing

- **Operating Rate:** Performance testing shall be conducted while the target engine operates at base load, defined as **not less than ninety percent (90%)** of maximum rated output (3,513 BHP/ 2,505 ekW). If an engine cannot achieve 90% load due to site ambient conditions, testing may be conducted at the maximum achievable load (≥ 80%), provided the tested load is logged and reported.
- **Fuel Firing:** Testing shall be conducted while firing 100% pipeline-quality natural gas. Fuel gas heat content (Btu/scf) and composition shall be logged continuously during testing via the certified online Gas Chromatograph.

e. Establishment of Aftertreatment Operating Parameters

During each performance test, the permittee shall continuously monitor and record the following parameters at least once every 15 minutes to establish or re-verify compliant baseline operating ranges:

- **Catalyst Inlet Temperatures:** Record average inlet temperatures (°F) for both Oxidation Catalyst and SCR beds across the three (3) test runs to confirm operation within certified light-off windows (≥ 450°F for OxCat and ≥300°C for SCR).
- **Baseline Differential Pressure (Δ P):** Measure and establish baseline pressure drop (inches H₂O) across Oxidation Catalyst and SCR beds during 100% load testing for ongoing daily parameter tracking under 40 CFR 63 Subpart ZZZZ Table 2b.
- **DEF Dosing & Algorithm Audit:** Log the automated DEF injection rate (gal/hr) to confirm the active controller dynamically trims dosing before stack ammonia slip exceeds 10.0 ppmvd @ 15% O₂.

f. Notification, Recordkeeping, and Reporting

- **Test Protocol Notification:** The permittee shall submit a site-specific test protocol to the Director in accordance with Condition 3.3.1.
- **Test Report Submission:** Final performance test reports for every engine tested (including Lead Engine verification data) shall be submitted to the Director and to EPA in accordance with Conditions 3.3.1., 3.5.3., and 5.5.4.
- **Record Retention:** All test reports, raw field data, strip charts, online GC fuel composition logs, calibration gas certificates, and individual engine operating hour records shall be maintained in accordance with Condition 3.4.1.

5.3.2. Performance Testing Requirements (PM₁₀, PM_{2.5}, and Ammonia Slip)

- a. Testing Schedule and Unit Selection. Within one hundred eighty (180) days after initial startup of the first engine in each Power Node, the permittee shall conduct a one-time performance compliance test on one (1) representative natural gas-fired engine per Power Node. Testing shall demonstrate compliance with the mass emission limits for Total PM₁₀, Total PM_{2.5}, and the concentration limit for ammonia (NH₃) slip exiting the Selective Catalytic Reduction (SCR) control system. This testing shall be conducted in accordance with Condition 3.3.1. and the following additional requirements:
- b. Approved Test Methods. All testing shall be conducted in accordance with test methods approved by the U.S. EPA and the Director. Approved methods include:
 1. Filterable PM₁₀ and PM_{2.5}: U.S. EPA Method 201A (40 CFR Part 51, Appendix M). If stack gas parameters (such as exhaust velocity or moisture) prevent the use of Method 201A, the permittee may use U.S. EPA Method 5 (40 CFR Part 60, Appendix A-3) as an approved alternative, with all captured filterable particulate matter conservatively assumed to be $\leq 2.5 \mu$.
 2. Condensable Particulate Matter (PM₁₀/PM_{2.5}): U.S. EPA Method 202 (40 CFR Part 51, Appendix M). Total PM₁₀ and Total PM_{2.5} shall be determined by summing the filterable and condensable fractions.
 3. Ammonia (NH₃) Slip: U.S. EPA Conditional Test Method 027 (CTM-027) or U.S. EPA Method 320 (40 CFR Part 63, Appendix A) using Fourier Transform Infrared (FTIR) Spectrometry.
- c. Operating Conditions During Testing.
 1. All performance tests shall be conducted while the engine is operating under normal maximum load conditions (defined as greater than or equal to 90% of maximum rated mechanical output, or the maximum load achievable during the test window).
 2. Tests shall be conducted while firing pipeline-quality natural gas under normal operating conditions. Testing shall not be performed during periods of startup, shutdown, or malfunction.
 3. During each test run, the permittee shall continuously monitor and record the following operating parameters:

- Engine mechanical output (bhp) and generator output (kW);
 - Fuel gas consumption rate (scf/hr) and heat input rate (MMBtu/hr);
 - Fuel gas Higher Heating Value (Btu/scf) recorded by the facility's online Gas Chromatograph;
 - Engine exhaust gas temperature entering and exiting the SCR system (°F); and
 - DEF injection rate (lb/hr or gal/hr) to the SCR system.
- d. Technical & Quality Assurance Protocols. Method 202 Artifact Safeguards:
1. To prevent sampling artifacts (such as dissolved gas oxidation or ammonium salt precipitation in low-concentration natural gas exhaust), the post-test nitrogen (N₂) purge specified in EPA Method 202 shall be executed immediately following each sampling run.
 2. Ammonia Slip Correlation: Ammonia slip testing shall be conducted simultaneously with SCR operational logging to verify that the ammonia injection control system maintains targeted NO_x reduction efficiency without exceeding the permitted ammonia slip concentration limit.
- e. Sampling Train Hardware & Equipment Specifications:

During all particulate matter performance testing incorporating EPA Methods 201A and 202, the permittee shall strictly utilize the following hardware configuration:

1. Filter Media: High-purity quartz fiber filters rated for temperatures up to 1,000°F for the filterable PM sampling assembly. Standard glass fiber filters are strictly prohibited.
 2. Seals and Gaskets: Graphoil gaskets, metallic seals, or high-temperature flexible materials for all probe, cyclone, and filter holder connections. Viton, silicone, or standard synthetic rubber O-rings subject to thermal degradation at 700°F are strictly prohibited.
 3. CPM Chiller Train: A high-capacity recirculating liquid chiller equipped with an active ice-water bath capable of continuously cooling the gas stream from 700°F down to sub-85°F temperatures.
- f. Notification and Test Protocol.

Due to the stack exhaust temperature of the Caterpillar G3520K engines approaches 700°F, the protocol shall include a dedicated *High-Temperature Sampling Plan* that explicitly details:

1. Volumetric flow setup sheets and aerodynamic cut-size (D₅₀) calculations for the EPA Method 201A cyclones, adjusted specifically for gas viscosity at 700°F.
2. Technical specifications confirming that all sampling train components, gaskets, and filter media exposed to the stack gas stream are rated for 700°F+ operation.

3. Chiller system cooling calculations demonstrating sufficient thermal extraction capacity to handle 700°F exhaust gas while maintaining condensable particulate matter (CPM) temperature limits.
- g. Reporting. A full, final test report detailing the results of the performance testing shall be submitted to the Director within sixty (60) days following the completion of testing in accordance with Condition 3.3.1.. The report shall include all raw field data, laboratory analytical reports, operational data logs recorded during each test run, and calculated mass emission rates (lb/hr) and concentration values (ppmv corrected to 15% O₂).
- h. Records of such testing shall be maintained in accordance with Condition 3.4.1.

5.4. Recordkeeping Requirements

- 5.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:
 - a. The date, place as defined in this permit, and time of sampling or measurements.
 - b. The date(s) analyses were performed.
 - c. The company or entity that performed the analyses.
 - d. The analytical techniques or methods used.
 - e. The results of the analyses; and
 - f. The operating conditions existing at the time of sampling or measurement.
- 5.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.
- 5.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:
 - a. The equipment involved.
 - b. Steps taken to minimize emissions during the event.
 - c. The duration of the event.
 - d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

 - e. The cause of the malfunction.
 - f. Steps taken to correct the malfunction.

- g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.
- 5.4.5. No later than the 15th day after the end of each month, the permittee shall determine the total emissions from each engine (emission points EP001 through EP864) individually, total for each fleet of engines, and total for all of the 864 engines that were emitted during the previous month and the 12-month rolling total to demonstrate compliance with the annual emission limits in Condition 5.1.8. The permittee shall utilize the most current operation and emission data available in determining actual emissions. Such records shall be maintained in accordance with Condition 3.4.1. of this permit.
- 5.4.6. Engine and Air Pollution Control Equipment Maintenance and Firmware Tracking Recordkeeping (EU-001 through EU-864)
- a. Maintenance Plan Requirement (40 CFR 60 Subpart JJJJ & 40 CFR 63 Subpart ZZZZ)
Pursuant to 40 CFR 60.4243(b)(2)(ii), 40 CFR 60.4245(a)(2), and 40 CFR 63.6655(e), the permittee shall prepare, implement, and maintain an on-site Engine and Control Device Preventive Maintenance Plan (PMP) for each primary power engine (EU-001 through EU-864). The permittee shall operate and maintain each engine, Oxidation Catalyst, SCR aftertreatment assembly, and associated continuous monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions at all times.
 - b. Mandatory Recorded Maintenance Activities
The permittee shall maintain detailed, individual logs (electronic or hard copy) for each engine serial number documenting all maintenance, repairs, inspections, and component replacements. Records shall include, at a minimum:
 - **Engine Mechanical & Ignition Servicing:**
 - Dates and engine operating hours at the time of routine maintenance (e.g., lubricating oil and filter changes, spark plug inspection/replacement, air filter servicing, and valve clearances);
 - Inspection, repair, or replacement of fuel injectors, gas admission valves, or air-fuel ratio control hardware; and
 - Engine mechanical overhaul history and component replacements.
 - **Control Module Firmware & Calibration Revisions (ADEM A6 ECM):**
 - Date and documentation of periodic checks (conducted at least annually) for Caterpillar ADEM A6 Engine Control Module (ECM) firmware, software, or operating system updates;
 - Details and logs of any updates or recalibrations applied to the ADEM A6 urea/DEF dosing maps or software algorithms; and
 - Verification that updated firmware or dosing maps comply with the lead-unit verification testing parameters required under Condition 5.3.1.
 - **Oxidation Catalyst & SCR Aftertreatment Servicing:**

- Date, engine operating hours, and description of any catalyst element cleaning (including chemical washing, thermal regeneration, or soot/ash blowing);
- Date and serial numbers of any partial or total catalyst bed additions, module rotation, or element replacements;
- Date of re-establishing the baseline differential pressure (ΔP) across the Oxidation Catalyst or SCR bed following a catalyst washing or replacement event (pursuant to 40 CFR 63 Subpart ZZZZ Table 2b);
- Inspection, cleaning, flushing, or replacement of DEF/urea injection nozzles, dosing pumps, and reductant supply lines; and
- Calibration, zero/span validation, or replacement of post-catalyst Smart NO_x sensors, temperature thermocouples, and differential pressure transmitters.

c. Catalyst Replacement Baseline Reset Protocol

Within fourteen (14) calendar days following the replacement or chemical washing of any Oxidation Catalyst or SCR catalyst element on any engine, the permittee shall measure and record the new baseline pressure drop (ΔP) across the catalyst bed at 100% operating load ($\pm 10\%$). This new baseline shall replace the previous baseline value for demonstrating ongoing compliance with the ± 2.0 inches H₂O pressure drop limit required by 40 CFR 63 Subpart ZZZZ Table 2b.

d. Data Retention & Accessibility

All maintenance logs, technician sign-off sheets, ADEM A6 firmware revision records, catalyst service invoices, and baseline re-establishment logs shall be maintained in accordance with Condition 3.4.1.

5.5. Reporting Requirements

- 5.5.1. Any deviations(s) of the allowable visible emission requirement for any emission source discovered during observations using 40 CFR Part 60, Appendix A, Method 9 must be reported in writing to the Director of the Division of Air Quality as soon as practicable, but within ten (10) calendar days, of the occurrence and shall include, at a minimum, the following information: the results of the visible determination of opacity of emissions, the cause or suspected cause of the violation(s), and any corrective measures taken or planned. Such notification shall be submitted in accordance with Section 3.5. of this permit. A record of such report shall be maintained in accordance with Condition 3.4.1.
- 5.5.2. Any deviation(s) of any of specific limitations or requirements in this section shall be reported in writing to the Director as soon as practicable, but in any case, within ten (10) calendar days of discovery of such deviation. Such notification shall be submitted in accordance with Section 3.5. of this permit. A record of such report shall be maintained in accordance with Condition 3.4.1.
- 5.5.3. For any instance where the results of the total sulfur monitoring of the as required in Condition 5.2.6. yields a concentration of or greater than the limit in Condition 5.1.4., the permittee shall notify the Director within 10 days of receiving the results of the sampling analysis. Such notification shall include the laboratory results/report, chain of custody of the sample, location that the sample was taken from, and date/time the sample was taken. This notification shall be submitted in accordance with Condition 3.5.1. and records of the notification maintained in accordance with Condition 3.4.1.

5.5.4. **Electronic Performance Test Reporting Standard (40 CFR 60 Subpart JJJJ, 40 CFR 63 Subpart ZZZZ, and WVDEP-DAQ)**

a. Federal CEDRI / CDX Electronic Reporting Requirement

- i. **Submission Window:** Within **sixty (60) calendar days** following the date of completing each performance test required by Condition 5.3.1 for any engine (EU-001 through EU-864), the permittee shall submit the full performance test report electronically to the U.S. EPA.
- ii. **CEDRI / ERT Format:**
 1. For all performance test methods supported by the EPA's Electronic Reporting Tool (ERT) at the time of the test (including EPA Methods 1–4, 5, 7E, 10, 18, and 25A), the permittee shall create the test report in the ERT format and submit the resulting XML package electronically through EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI).
 2. For any test method not supported by the ERT at the time of testing (e.g., specialized FTIR or CTM-027 methods), the permittee shall submit an electronic portable document format (PDF) file of the complete performance test report via CEDRI.

b. State Agency (WVDEP-DAQ) Concurrent Submission

Concurrently with the federal CEDRI submission (and no later than 60 days following test completion), the permittee shall submit an electronic copy of the complete performance test report to the Director in accordance with Condition 3.3.1. The state submission shall include:

- The full ERT file package or complete PDF test report;
- Raw continuous emission monitoring (CEMS) strip charts and field data sheets;
- Real-time online Gas Chromatograph (GC) fuel heat content and composition logs logged during the test runs;
- Certified calibration gas cylinder laboratory certificates; and
- SCADA logs verifying individual engine load (kW/BHP), oxidation catalyst temperature, SCR inlet temperature, and DEF injection rate during each test run.

c. CEDRI System Outage / Claim of Uncontrollable Event

If the permittee is unable to submit the electronic report through CEDRI within the 60-day deadline due to a planned or unplanned operational outage of EPA's CDX/CEDRI system, or due to a force majeure event beyond the permittee's control:

- i. The permittee must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
- ii. The permittee must provide to the Administrator a written description identifying:
 1. The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

2. A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;
3. A description of measures taken or to be taken to minimize the delay in reporting; and
4. The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

6.0. Specific Requirements for Fuel Gas Heaters (EU883 through EU888).

6.1. Limitations and Standards

- 6.1.1. The following conditions and requirements are specific to the fuel gas heaters (EU883 through EU888):
- a. NO_x emissions emitted to the atmosphere from each heater shall not exceed 1.50 pounds per hour and 6.55 tons per year on a rolling 12-month basis.
 - b. CO emissions emitted to the atmosphere from each heater shall not exceed 1.26 pounds per hour and 5.50 tons per year on a rolling 12-month basis.
 - c. PM emissions to the atmosphere from each heater shall not exceed 0.03 pounds per hour and 0.12 tons per year on a rolling yearly total basis, which includes filterable and condensable forms of particulate matter.
 - d. PM₁₀, and PM_{2.5} emissions to the atmosphere from each heater shall not exceed 0.12 pounds per hour and 0.50 tons per year on a rolling yearly total basis, which includes filterable and condensable forms of particulate matter.
 - e. VOC emissions to the atmosphere from each heater shall not exceed 0.08 pounds per hour and 0.36 tons per year.
 - f. Visible emissions from the corresponding emission point associated with each heater shall not be greater than ten (10) percent opacity based on a six-minute average.
[45 CSR §2-3.1.]
 - g. Emissions of CO₂e from the heaters shall not exceed 7,816 tons per year on a rolling 12-month basis.
 - h. Each heater shall be designed or constructed with a maximum design heat input not to exceed 15.25 MMBtu/hr. This condition satisfies compliance with the limitation of 45 CSR §2-3.1.
[45 CSR 2A-3.1.a.]
 - i. Automated Temperature Modulation: The automated burner management system (BMS) for EU883–EU888 shall modulate heat input to maintain downstream fuel gas temperature at no more than 10°F above the calculated water/hydrate dew point temperature, and at no time shall the downstream fuel gas outlet temperature exceed 70°F during normal operation.
 - j. In accordance with 45 CSR §14-8.3., the permittee shall implement and maintain the following measures in applying the Best Available Control Technology for NO_x, CO, PM, PM₁₀, PM_{2.5}, VOCs and Greenhouse Gases emissions generated from each heater by:
 - i. Each heater shall be equipped and maintained with low-NO_x burners to a NO_x rate of no greater than 0.1 lb of NO_x per MMBtu.
 - ii. The permittee shall combust Pipeline Quality Natural Gas exclusively in each fuel gas heater (EU883 through EU888). To satisfy SO₂ Best Available Control Technology (BACT) and state fuel-burning requirements, the natural gas combusted shall not exceed a total sulfur content of 0.20 *grains of total sulfur per 100 standard cubic feet* (0.20 *gr S/100scf*), equivalent to approximately 3.4 *ppmv*, calculated on a 12-month

rolling average basis. At no time, any single reading/measurement shall exceed 0.50 *gr S/100scf*.

[45CSR§10-3.3.f. and 45CSR14-8.3.]

- iii. The permittee shall conduct tune-ups of each heater in accordance with the applicable requirements of 40 CFR 63, Subpart DDDDD. Each heater has a maximum design heat input capacity of 15.25 MMBtu/hr (greater than 10 MMBtu/hr); accordingly, the initial tune up for each heater shall be conducted no later than 13 months after initial startup of the heater, and each subsequent annual tune-up shall be conducted no later than 13 months after the previous tune up. [40 CFR §§63.7515(d), 63.7540(a)(10)]. If the unit is not operating on the required date for a tune-up, then the tune-up must be conducted within 30 calendar days of re-starting of the unit. [40 CFR §63.7540(a)(13)] These tune-ups shall consist of the following:

[40CFR§63.7515(d), §63.7540(a)(10)]

1. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (The permittee may delay the burner inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection).

[40 CFR §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 §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, not to exceed 36 months from the previous inspection);

[40 CFR §7540(a)(10)(iii)]

4. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, and with nitrogen oxide requirement in subparagraph i.i. of this condition (Condition 6.1.1.j.i); and

[40 CFR §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.

[40 CFR §7540(a)(10)(v)]

[45 CSR §14-8.3, 40 CFR §63.7500], and Table 3 to Subpart DDDDD of Part 63—Work Practice Standards]

6.2. Monitoring Requirements

- 6.2.1. The permittee shall record the actual amount of fuel consumed or actual operating hours for each heater (EU883 through EU888) for each calendar month and determine actual emissions emitted during the corresponding month. On a rolling 12-month total, the permittee shall demonstrate compliance with the annual limits of items a through d of Condition 6.1.1. Such records shall be maintained in accordance with Condition 3.4.1.

- 6.2.2. The permittee shall keep the following records in accordance with 40 CFR §63.7540(a)(10)(vi) as required to be conducted in Condition 6.1.1.j.iii. for each heater:
[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 using a portable combustion analyzer
[40 CFR §63.7540(a)(10)(vi)(A)]
 - b. A description of any corrective actions taken as a 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 of the unit, but only if the unit was physically and legally capable of using more than one type of fuel during that period.
[40 CFR §63.7540(a)(10)(vi)(C)]

These records shall be maintained in accordance with Condition 3.4.1.

- 6.2.3. **Visible Emissions Monitoring of Emission Points EP883 - EP888:** To demonstrate ongoing compliance with the visible emissions (opacity) limit of Condition 6.1.1.f., the permittee shall conduct periodic tiered visible emissions monitoring of the Emission Points EP883, EP884, EP885, EP886, EP887, and EP888 for normal operation of the fuel gas heaters. Visible emission under this shall not be conducted within 60 minutes of startup of the heater or 60 minutes prior to a scheduled shutdown of the heater.
- a. **Tier 1 Screening (U.S. EPA Method 22):**
 1. The permittee shall conduct a visible emissions observation using U.S. EPA Method 22 (40 CFR Part 60, Appendix A) at least once per calendar half-year (semi-annually).
 2. The Method 22 observation shall be conducted for a continuous duration of exactly **six (6) minutes** while the heater is operating.
 3. If no visible emissions are observed, or if visible emissions are observed for **less than thirty (30) seconds** during the 6-minute observation period, the unit is deemed to be in compliance and no further action is required for that monitoring period.
 - b. **Tier 2 Quantification (U.S. EPA Method 9) and Corrective Action:** If visible emissions are observed for thirty (30) seconds or more during the Tier 1 screening, the permittee shall immediately log a deviation and take one of the following actions:
 1. **Immediate Maintenance:** The permittee may immediately shut down the heater, perform corrective maintenance (e.g., burner tuning or cleaning), and restart the unit. Within 24 hours of restarting the unit, the permittee shall conduct a new Tier 1 screening. If the unit passes the new screening, no Method 9 observation is required.
 2. **Method 9 Observation:** If maintenance is not performed, or if the unit fails a subsequent Tier 1 screening, the permittee shall conduct a formal U.S. EPA Method 9 observation (40 CFR Part 60, Appendix A) within **seventy-two (72) hours** of the failed Method 22 screening. The Method 9 observation must be conducted by a certified visible emissions evaluator while the heater is operated to determine compliance with the 10% opacity standard.

c. Recordkeeping Requirements: The permittee shall maintain records of all visible emissions monitoring in accordance with Condition 3.4.1. Records shall include:

1. The date, time, and duration of all Method 22 and Method 9 observations.
2. The name and affiliation of the observer, and (if applicable) a copy of their current Method 9 certification.
3. The results of the observations, including the total time of visible emissions during Method 22 checks, and the calculated 6-minute averages for any Method 9 checks.
4. Details of any corrective maintenance performed on the heater as a result of a failed Tier 1 screening.

6.2.4. **SCADA Integration:** The permittee shall continuously monitor and record downstream fuel gas temperature (°F), burner firing status, and live GC dewpoint calculations via the facility SCADA system to verify compliance with the fuel gas heater operational limitation of Condition 6.1.1.h. Records shall be retained in accordance with Condition 3.4.1., which shall include the status of each heaters, date/time the heater started operating, downstream gas temperature, dew point of the incoming natural gas, and all instances that any of the heaters operated with the downstream gas temperature was greater than 10°F dew point temperature or 70°F, and all calibrations or calibration checks for all instruments used in the monitoring system.

6.2.5. **Periodic Fuel Gas Heater Emission Screening Monitoring (NO_x, CO, and O₂) (EU883 through EU888)**

a. Sampling Frequency & Schedule:

1. The permittee shall conduct periodic emission screening monitoring for NO_x, CO, and O₂ on each fuel gas heater (EU883 through EU888) at least **once per calendar semi-annual period** (spaced at least 90 days apart) while operating.
2. If a designated heater is out of service during a scheduled semi-annual monitoring event, the screening requirement for that unit is suspended for that monitoring period, provided the permittee logs the out-of-service hours in accordance with Condition 6.2.1.
3. Any fuel gas heater undergoing burner overhaul, low-NO_x burner replacement, or major combustion system maintenance shall undergo screening monitoring within fourteen (14) operating days following return to routine service.
4. Any fuel gas heater that operates **fewer than 100 hours** during a calendar semi-annual period shall be exempt from the screening monitoring requirement for that semi-annual period. The permittee shall document eligibility for this exemption using the operating hour logs required pursuant to Condition 6.2.1. If an exempt unit subsequently operates for 100 hours or more in a semi-annual period (six month period), screening monitoring shall be conducted within thirty (30) operating days.

b. Instrument Performance & Monitoring Methodology:

1. Monitoring shall be conducted using a low-range portable electrochemical cell analyzer (0.1 ppm resolution) or a portable optical analyzer operating in accordance with **EPA CTM-030, EPA CTM-034, or ASTM D6522.**

2. Calibration span gases shall be selected to accurately span the permitted BACT limits and shall not exceed 81.0 ppmvd for NO_x and 112.0 ppmvd for CO.
3. Screening shall consist of one (1) continuous monitoring run of at least fifteen (15) minutes of stable data collection while the heater operates at normal operating load (> 50% rated heat input capacity).
4. Measured NO_x and CO concentration readings shall be corrected to **three percent (3%) oxygen (O₂), dry basis**, using the following formula:

$$Concentration_{@ 3\% O_2} = Concentration_{measured} \times \left(\frac{20.9 - 3.0}{20.9 - \%O_{2, measured}} \right)$$

c. Corrective Action & Trigger Thresholds:

If the corrected screening concentration exceeds **81.0 ppmvd NO_x @ 3%O₂** (0.1 lb/MMBtu) or **112.0 ppmvd CO @ 3% O₂** (0.037 lb/MMBtu):

1. The permittee shall record the excursion and initiate corrective tuning actions (e.g., air-to-fuel ratio adjustment, burner cleaning, or flame pattern adjustment) within twenty-four (24) hours.
2. The permittee shall repeat the screening test within seven (7) calendar days of completing corrective actions.
3. If the re-test fails to demonstrate compliance with the trigger thresholds, the unit shall be scheduled for formal burner maintenance or stack testing, and the event shall be recorded in the facility deviation log.

d. Step-Down Provision:

1. If all six (6) fuel gas heaters demonstrate corrected concentrations less than 30.0 ppmvd NO_x and 50.0 ppmvd CO at 3% O₂ for **two (2) consecutive semi-annual checks**, the monitoring frequency for the heaters may be reduced to **annual**.
2. If any subsequent annual test exceeds these thresholds, all fuel gas heaters shall immediately revert to semi-annual monitoring until the step-down criteria in Condition 6.2.5.d.1 are met again.

e. Recordkeeping Requirements: Records of periodic monitoring shall be maintained on-site for five (5) years in accordance with Condition 3.4.1 and shall include:

1. Date, start/stop time, and Emission Unit ID (EU883 through EU888);
2. Heater operating load (MMBtu/hr heat input or fuel firing rate in scf/hr);
3. Raw measured concentrations (ppmv NO_x, ppmv CO, and % O₂);
4. Corrected concentrations (ppmvd NO_x @ 3%O₂ and ppmvd CO @ 3% O₂);
5. Analyzer make, model, serial number, sensor specs, and NIST-traceable calibration gas certificates; and

6. Technician name and details of any burner adjustments or maintenance performed.

6.3. Testing Requirements

- 6.3.1. The permittee shall conduct performance testing within 100 days of fuel gas heater emission screening monitoring, which is required to be conducted by Condition 6.2.5., that the results indicated that a heater exceeded the trigger threshold in accordance with subparagraph c.3. of Condition 6.2.5. This testing shall be performed in accordance with EPA Test Method 7 for NO_x, EPA Test Method 10 for CO, and Condition 3.3.1. Records of such testing shall be maintained in accordance with Condition 3.4.1. and a report shall be submitted to the Director in accordance with Conditions 3.4.1. and 3.5.3.

6.4. Reporting Requirements

- 6.4.1. The permittee shall submit a "Notification of Compliance Status" for heaters identified as EU883 through EU888 to the Director before the close of business on the sixtieth (60th) day after completion of the initial compliance demonstration as required in Condition 6.1.1.j.iii. Such "Notification of Compliance Status" shall be in accordance with 40 CFR §63.9(h)(2)(ii) and contain the information specified in 40 CFR §§63.7545(e)(1), and (8), which includes a statement the initial tune-up for each heater was completed.
[40 CFR §63.7545(e)]
- 6.4.2. The permittee shall submit "Annual Compliance Reports" for EU883 through EU888 electronically using CEDRI that is accessed through the EPA's Center Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form for this report is not available in CEDRI at the time the report is due, the permittee shall submit the report to the Administrator and Director using the addresses listed in Condition 3.5.3. The first biennial (every two years) compliance report shall be submitted no later than two years after the initial start-up of the unit and the first date ending on January 31. Subsequent reports shall be submitted once every two years afterwards. Such reports shall contain the information specified in 40 CFR §§63.7550(c)(1) which are:
- a. Permittee and facility name, and address;
 - b. Process unit information, emission limitations, and operating limitations;
 - c. Date of report and beginning and ending dates of the reporting period;
 - d. Include the date of the most recent tune-up for each heater; and
 - e. Include the date of the most recent burner inspection if it was not done on a five-year frequency and was delayed until the next scheduled or unscheduled unit shutdown.

The permittee shall maintain records of such reports in accordance with Condition 3.4.1.
[40 CFR §§63.7550(b), (b)(1), (c)(1), & (c)(5)(i) though (iv) and (xiv), and (h)(3)]

7.0. Specific Requirements for Emergency Engines (EU865-EU882)

7.1. Limitations and Standards

7.1.1. **Emergency Generators (EU865 through EU876):** The following requirements apply to the twelve (12) diesel-fired emergency generators:

- a. **NSPS Subpart IIII Certification Standards:** Each engine shall be an EPA-certified Tier 2 emergency compression ignition engine complying with 40 CFR § 60.4202(a)(2) and § 60.4205(b). Exhaust emissions shall not exceed:
 - i. **NMHC + NO_x:** 6.4 g/kW-hr (4.8 g/HP-hr)
[40CFR§60.4205(b)]
 - ii. **CO:** 3.5 g/kW-hr (2.6 g/HP-hr)
[40CFR§60.4205(b)]
 - iii. **PM:** 0.20 g/kW-hr (0.15 g/HP-hr)
[40CFR§60.4205(b)]
- b. **Mass Emission Limits:** Hourly emissions from each engine shall not exceed the following rates on a 3-hour average basis:

Table 7.1.1.b. Mass Emissions Limits for each emergency generator engine (EU865-EU876)	
Pollutant	Hourly Rate (lb/hr per engine)
Oxides of Nitrogen (NO _x)	14.11
Carbon Monoxide (CO)	8.13
Particulate Matter (PM/PM ₁₀ /PM _{2.5})	0.47
Volatile Organic Compounds (VOCs) (Formaldehyde emissions are include)	0.74
Formaldehyde	0.01

- d. Each generator set shall be equipped with an engine or engine configuration that has been certified by the manufacturer to comply or conform with either 40 CFR §60.4205(b), which refers to 40 CFR §§89.111 and 112 or 40 CFR Part 60.
[40 CFR §§60.4211(a)(3) and (c)(1)]
- e. **Power Output:** Each engine shall not have a nameplate power rating greater than 1,412 brake horsepower (bhp).
- f. **Fuel Specifications:** Each engine shall be fueled exclusively with diesel fuel that meets the specifications stated in Condition 7.1.3.
- g. **Hour Meter:** The engine shall be equipped prior to initial startup, and maintained for the life of the engine, with a non-resettable hour meter. Should the hour meter need to be repaired or replaced, the permittee shall notify the Director in accordance with Condition 3.5.3. within 15 calendar days of the repair/replacement. Such notice shall include the actual reading prior to the repair/replacement, the scope of work performed, the individual supervising the repair, and the date/time the work was completed.

h. **Operation and Maintenance:** The permittee shall keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine and associated control device (if equipped) in a manner consistent with good air pollution control practice for minimizing emissions.

[40 CFR §60.4211(a)(1)]

i. The permittee shall only change those emission-related settings of each generator set that are permitted by the manufacturer.

[40 CFR §60.4211(a)(2)]

7.1.2. **Fire Water Pumps (EU877 through EU882):** The following requirements apply to the six (6) diesel-fired fire water pump engines:

a. **NSPS Subpart IIII Certification Standards:** Each engine shall be an EPA-certified fire pump engine complying with 40 CFR § 60.4205(c) and Table 4 to Subpart IIII. Exhaust emissions shall not exceed:

i. NMHC +NO_x: 4.0 g/kW-hr (3.0 g/HP-hr)

ii. CO: 3.5 g/kW-hr (2.6 g/HP-hr)

iii. PM: 0.20 g/kW-hr (0.15 g/HP-hr)

[40 CFR § 60.4205(c) and Table 4 to 40 CFR 60 Subpart IIII]

b. **Mass Emission Limits:** Hourly mass emissions from each fire pump engine shall not exceed:

Table 7.1.2.b. Mass Emissions Limits for each engine (EU877-EU882)	
Pollutant	Hourly Rate (lb/hr per engine)
Oxides of Nitrogen (NO _x)	2.43
Carbon Monoxide (CO)	2.30
Particulate Matter (PM/PM ₁₀ /PM _{2.5})	0.13
Volatile Organic Compounds (VOCs)	0.20
Formaldehyde	0.01

c. **Power Output:** The nameplate power rating for each engine shall not be greater than 400 bHP (298 kW).

d. **RICE MACT Streamlining:** Pursuant to 40 CFR § 63.6590(c)(6), compliance with 40 CFR 60 Subpart IIII satisfies all Part 63 requirements.

7.1.3. **Common Fuel Quality Specifications:** Diesel fuel combusted in all emergency engines (EU865–EU876 and EU877–EU882) shall be Ultra-Low Sulfur Diesel (ULSD) meeting 40 CFR § 80.510(b) / § 1090.305, with a maximum sulfur content of 15 *ppm* (0.0015% by weight) and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

[40 CFR §§60.4207(b)]

7.1.4. **Common Operational Restrictions & Non-Emergency Hour Caps:** Emergency engines (EU865–EU876 and EU877–EU882) shall be operated in accordance with the following requirements:

- a. **Emergency Operation:** There is no time limit on the use of emergency engines during bona fide emergency situations.
[40 CFR § 60.4211(f)(1)]
 - b. **Maintenance and Testing Limit:** Each engine is limited to a maximum of 100 hours per calendar year for maintenance checks and readiness testing.
[40 CFR § 60.4211(f)(2)(i)]
 - c. **Prohibited Non-Emergency Operations:** Emergency engines shall **not** be operated for peak shaving, non-emergency demand response, or to generate income/supply power under financial arrangements with third parties.
[40 CFR § 60.4211(f)]
 - d. **Operating Schedule Restriction:** Non-emergency operation to include maintenance and testing checks for all emergency engines shall be restricted exclusively to the hours between 9:00 AM (0900 hours) and 4:00 PM (1600 hours) local time. For each of the three data centers (DC), no emergency engine shall be operated concurrently with any other emergency engine at the same data center during non-emergency operations.
 - e. **Hour Meter & Equipment Settings:** Each engine shall be equipped prior to startup with a non-resettable hour meter. The permittee shall operate and maintain the certified engines according to manufacturer written instructions and alter only those emission-related settings permitted by the manufacturer.
[40 CFR § 60.4209(a) and § 60.4211(a)]
 - f. **Manufacturer Compliant Engine:** Each engine shall be certified compliant to the emission standards no later than the 2026 model year engine or later.
[40 CFR §§60.4211(a)(3) and (c)(1)]
 - g. **Engine Maintenance:** Each engine and associated control device (if equipped) shall be maintained in accordance with the manufacturer's written instructions.
 - h. **Emissions Settings:** The permittee shall only change those emission-related settings of each generator set that are permitted by the manufacturer.
[40 CFR §60.4211(a)(2)]
 - i. **BACT Requirement:** Tune-up each engine once every five years in accordance with the manufacturer's specifications.
[45 CSR §14-8.3]
- 7.1.5. **Operational Work Practice Standards and Good Engineering Practices for Diesel Storage Tanks:** The permittee shall comply with the following requirements for the diesel storage vessels at the facility..
- a. Tank Design and Submerged Fill Requirements
 - Submerged Loading Standard: Liquid fuel shall be introduced into each storage tank via a permanently installed submerged fill pipe extending to within six (6) inches of the tank bottom, or via an equivalent bottom-loading configuration, to minimize liquid turbulence and splash evaporative losses during refilling operations.
 - b. Equipment Integrity and Vapor Tightness

- Closed Hatch Maintenance: All fill pipes, gauge hatches, thief hatches, sampling ports, and manual liquid level measuring connections shall be equipped with vapor-tight caps or covers fitted with liquid- and vapor-tight gaskets.
 - Operational Position: All hatches, caps, and covers shall remain securely closed and latched at all times except during active fuel delivery, sampling, or routine tank gauging.
 - Pressure/Vacuum Relief Valves: Any installed pressure/vacuum (P/V) vent valves shall be maintained in good operating condition and set to operate in accordance with manufacturer specifications to prevent unnecessary breathing losses during ambient temperature shifts.
- c. Spill, Overfill, and Secondary Containment Controls
- Overfill Protection: Each storage tank shall be equipped with a functional overfill prevention system (e.g., high-level alarm, automatic flow shutoff valve, or restrictor valve set at $\leq 95\%$ capacity) to prevent fuel spillage during deliveries.

7.2. Monitoring Requirements

- 7.2.1. The permittee shall measure and record the duration of the operation of each engine on a monthly basis through the use of the non-resettable hour meter of each respective engine, start and end times, date, and the purpose of the operation. These records shall be maintained in accordance with Condition 3.4.1. of this permit.
- 7.2.2. The permittee shall conduct monthly inspections of each diesel fuel tank at the facility. These inspections shall consist of the following:
- a. **Monthly Visual Inspections:** The permittee shall conduct monthly visual inspections of each diesel storage tank, piping, valves, fittings, hatches, gaskets, and surrounding containment areas to check for signs of structural degradation, corrosion, seal wear, or liquid leaks.
 - b. **Prompt Defect Correction:** Any identified fuel leak, damaged gasket, cracked hose, or malfunctioning valve shall be repaired or replaced within **fifteen (15) calendar days** of discovery.

A log of all monthly visual tank inspections, identified maintenance defects, and corresponding corrective repairs completed shall be maintained in accordance with Condition 3.4.1.

7.3. Recordkeeping Requirements

- 7.3.1. Record of Monitoring. The permittee shall keep records of monitoring information that include the following:
- a. The date, place as defined in this permit, and time of sampling or measurements.
 - b. The date(s) analyses were performed.
 - c. The company or entity that performed the analyses.
 - d. The analytical techniques or methods used.
 - e. The results of the analyses; and

- f. The operating conditions, as specified in Condition 7.2.1. existing as specified at the time of sampling or measurement.
- 7.3.2. Record of Maintenance of Air Pollution Control Equipment. For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.
- 7.3.3. Record of Malfunctions of Air Pollution Control Equipment. For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:
 - a. The equipment involved.
 - b. Steps taken to minimize emissions during the event.
 - c. The duration of the event.
 - d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

- e. The cause of the malfunction.
 - f. Steps taken to correct the malfunction.
 - g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.
- 7.3.4. **Engine Maintenance Records:** The permittee shall keep a maintenance plan and records of all maintenance performed on each engine to demonstrate compliance with the manufacturer's emission-related specifications, which shall include engine tune-ups.
[40 CFR § 60.421(a)(1)]
- 7.3.5. The permittee shall maintain records of the following regarding deliveries of ULSD at the facility:
 - a. Vendor fuel delivery receipts or Certificates of Analysis (COA) confirming that all delivered fuel is ULSD (≤ 15 ppm S); and
 - b. Monthly records of total diesel fuel delivered to each tank (gallons).

7.4. Reporting Requirements

- 7.4.1. **RICE MACT Initial Notification:** The permittee shall submit an initial notification to the Director for each emergency generator (EU865-EU876) to satisfy initial notification requirements of Subpart ZZZZ of 40 CFR 63 within 15 calendar days after the initial startup date of each emergency generator. Such notification shall include the following information and a statement that the emergency generator 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) and in accordance with Condition 3.4.1.
[40 CFR §§63.9, §63.6590(b) and §63.6645(f)]
 - a. The name and address of permittee;

[40 CFR §63.9(2)(i)]

- b. The address (i.e., physical location) of the affected source (emergency generator);
[40 CFR 63.9(2)(ii)]
- c. An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;
[40 CFR §63.9(2)(iii)]
- d. A brief description of the nature, size, design, and method of operation of the source and an identification of the types of emission points within the affected source subject to the relevant standard and types of hazardous air pollutants emitted; and
[40 CFR §63.9(2)(iv)]
- e. A statement of whether the affected source is a major source or an area source.
[40 CFR §63.9(2)(v)]

APPENDIX A Visible Emissions Observation (example form)

Date of Observation: _____

Data Entered by: _____

Reviewed by: _____

Date Reviewed: _____

Describe the General Weather Conditions:

Emission Point ID	Emission Point Description	Time of Observation	Visible Emissions? Yes/No	Consecutive Months of Visual Emissions	Comments

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached _____, representing the period beginning _____ and ending _____, and any supporting documents appended hereto, is true, accurate, and complete.

Signature¹

(Please use blue ink)

Responsible Official or Authorized Representative

Date

Name & Title

(Please print or type)

Name

Title

Telephone No. _____

Fax No. _____

¹ This form shall be signed by a “Responsible Official.” “Responsible Official” means one of the following:

- a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such 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 and either:
 - (i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars), or
 - (ii) the delegation of authority to such representative is approved in advance by the Director.
- b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively.
- c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or
- d. The designated representative delegated with such authority and approved in advance by the Director.